Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

March 29, 2012

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

Attention: Ms. Alanna Gillis, Acting Commission Secretary

Dear Ms. Gillis:

Re: FortisBC Energy Inc. ("FEI")
Application for a Certificate of Public Convenience and Necessity ("CPCN") for Constructing and Operating a Compressed Natural Gas Refueling Station at BFI Canada Inc.

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 1.

On February 29, 2012, FEI filed the Application as referenced above. In accordance with Commission Order No. G-23-12 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If there are any questions regarding the attached, please contact Shawn Hill at 604-592-7840 or Mark Grist at 604-592-7874.

Yours very truly,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

1.0 TERMINOLOGY

Reference: Exhibit B-1, Section 2.2, p. 2; Exhibit A2-5, p.1

In a footnote on page 2 of the Application, FortisBC Energy Inc. (FEI) has indicated that going forward it has changed its terminology from Natural Gas Vehicles (NGV) to Natural Gas for Transportation (NGT) as NGT more accurately, in FEI's view, describes FEI's target markets.

1.1 Please provide the definition that FEI is using for the word "vehicles". For instance is it "motor vehicle" or the broader definition "a means of transporting or carrying something"?

Response:

This response addresses BCUC IR 1.1.2 as well.

The change in FEI's terminology from Natural Gas Vehicles (NGV) to Natural Gas for Transportation (NGT) was made to align with industry terminology. Facilitated by Natural Resources Canada, the *Natural Gas Use in the Canadian Transportation Sector Deployment Roadmap* working group has led the proposed adoption of this term.

In FEI's view, "vehicles" can refer to a broader means of transportation, which includes on-road and off-road motor vehicles as well as marine vessels. But FEI believes that these terms are interchangeable in the context of CNG/LNG refueling services to be provided by FEI. Consistent with the current industry convention, the Company's intention at this time is to primarily use NGT terminology.

The change of terminology does not change the Company's target market focus on return-to-base fleets of buses, heavy duty and vocational trucks; nor is FEI proposing any additional target markets related to this change in terminology. This target market focus is consistent with FEI's 2010 Long Term Resource Plan (at page 64) and the CNG-LNG Application (Appendix A-1, at page 8).

1.2 Please describe the NGT target market that FEI has identified that does not fall within the definition of "vehicle".

Response:

Please see our response to BCUC IR 1.1.1.

1.3 How does FEI's change in terminology align with the wording in General Terms and Conditions 12B – Vehicle Fueling Stations (GT&C 12B) which states "FortisBC Energy will provide CNG and LNG Services to vehicles in accordance with the provisions of this section"?

Response:

This response also addresses BCUC IRs 1.1.4 and 1.1.4.1.

For clarification, what FEI provides under Section 12B of the General Terms and Conditions is CNG fueling service. As stated in response to BCUC IR 1.1.1, the word "vehicle" and "transportation" are interchangeable in the context of the CNG/LNG fueling services provided by FEI, and the change of terminology does not change FEI's targeted market. Thus, FEI's change in terminology from NGV to NGT does not affect the application of Section 12B of the GT&Cs. Use of the term "NGT" continues to align with Section 12B of the GT&Cs, and all NGT customers will continue to receive CNG/LNG fueling service under GT&C Section 12B, In this case BFI has signed a contract that conforms to the terms and conditions set forth in GT&C Section 12B, and they will fuel CNG powered vehicles or waste transportation vehicles though this station.

1.4 In FEI's view, will GT&C 12B be the applicable service offering for all NGT customers?

Response:

Please see our response to BCUC IR 1.1.3.

1.4.1 If not, does FEI anticipate it will need to develop additional tariff offerings for the broader NGT market?

Response:

Please see our response to BCUC IR 1.1.3.

2.0 FEI'S CNG/LNG SERVICE OFFERING

Reference: Exhibit B-1, Section 2.2, p. 2; Exhibit A2-10, pp. 4, 18, 19

Section 2.2 of the Application describes the approved CNG compression and dispensing services to be provided by FEI, in terms of Order G-128-11 and what FEI refers to as the "NGT Application".

The Panel in the FEI Compressed Natural Gas (CNG) Service Agreement and CNG and Liquefied natural Gas (LNG) General Terms and Conditions (CNG/LNG Service) Decision found "that a CNG/LNG fuelling infrastructure has no natural monopoly characteristics and the service offerings applied for would not be subject to regulation, unless the services were being provided by an organization that is already a regulated public utility… The Commission Panel acknowledges that the Utilities Commission Act does not prohibit FEI from providing CNG/LNG service offerings but that, unlike other potential market participants, if it does so, it will be subject to regulation. FEI is subject to regulation because it is otherwise a monopoly, and the regulatory framework exists to protect the public from monopolistic behaviour and the potential associated problems... In the circumstances of this Application, the fuel dispensing service has no natural monopoly characteristics and could potentially be supplied by any number of competitors."

2.1 Please confirm that the CNG compression service, by itself, is not a regulated activity in British Columbia?

Response:

The CNG fueling service provided by FEI includes two main components: compression and dispensing, and is offered by FEI according to Section 12B of the FEI's General Terms and Conditions (approved by Order No. G-14-12), which was revised based on the NGT Decision.

FEI confirms that CNG fueling service is not a regulated activity in British Columbia, unless the entity providing the CNG refueling service is already a public utility. This is consistent with the Commission's previous decision. (See NGV Decision, pp. 18-19; see also AES Inquiry, FEU Final Submission, item 191, page 82).

2.2 Is the compression service, by itself, a regulated activity in other jurisdictions? Please discuss.

Response:

Based on FEI's research, the NGT business in North America is still developing and many jurisdictions are considering what role the state or provincial public utility commissions and public utilities should be playing in growing the NGT market. Governments in North America are encouraging the development of the NGT market to meet challenges of rising fuel prices and to fight global warming by reducing GHG emissions[1]. Jurisdictions in the United States are at a more advanced stage than those in Canada in the development of CNG/LNG Fueling Service.

FEI understands that in most states in the United States that regulate natural gas utilities, they have the option to offer a regulated or unregulated NGT Service[2]. Non-regulated providers can offer unregulated NGV Service. To grow the NGV Service, states are encouraging the involvement of utilities. For example California's "State Alternative Fuels Plan 2007" states that "the private sector, including electric and natural gas utilities, must become major new investors in electric drive and natural gas vehicle technologies"[3]. The policies regarding the NGT service offering vary from state to state.

As an example, Utah is one of the states where the NGV business is fast growing. Questar Gas owns and operates 25 NGT fueling stations in Utah[4]. Questar's NGT service, which includes compression and dispensing service, is regulated by the Public Service Commission of Utah. Questar Gas therefore offers rate based natural gas vehicle services.

As stated in the NGT Application in California PG&E operates 37 CNG stations, 24 with public access. PG&E's commercial rate (GNGV2) applies to the sale of CNG at PG&E-owned stations, and is charged every fill.[5]

Oklahoma Natural Gas operates 31 CNG stations throughout Oklahoma State and charges fleet operators a tariff for the fueling service. The rate which is designed for commercial and industrial customers is charged as a volumetric delivery fee and a nominal fixed service charge in addition to the commodity cost of gas[6].

In Canada, provincial jurisdictions have different policies related to NGT service as the energy policies and legal framework regarding the public utility services between jurisdictions are different. To FEI's knowledge, GazMetro Solutions, a subsidiary company of GazMetro provides LNG/CNG fueling service, but such service is not regulated due to its regulatory

---

[1] http://www.cngva.org/en/home/canadas-industry/natural-gas-for-transportation-deployment-roadmap.aspx and http://www.usgasvehicles.com/news_detalle.php?id=1485
[2] Discussion with official of NGVAmerica
[3] http://www.energy.ca.gov/2007publications/CEC-600-2007-011/CEC-600-2007-011-CMF.PDF
[4] http://www.questargas.com/FuelingSystems/NGV/ngv.php
[5] NGV Application Appendix A-2 page 25
[6] NGV Application Appendix A-2 page 26

framework. No other natural gas utilities are offering the fueling services. FEI thus is taking the lead among Canadian natural gas utilities in the development of natural gas as a transportation fuel by offering CNG/LNG fueling service in order to mitigate declining throughput as well as providing support for British Columbia's energy objectives. As shown in the Ministry of Energy and Mines' recent natural gas strategy document, the Provincial government is keen on promoting natural gas as a transportation fuel.[7] FEI's CNG/LNG fueling service is consistent with this strategy.

FEI is committed to provide compression and dispensing service for CNG fueling ("CNG Service"), which in British Columbia is subject to regulation when provided by a public utility. .

See the response to BCUC IR 1.2.1 for a discussion on this topic. FEI believes that the most appropriate business strategy for development of the British Columbia NGT market involves public utilities, such as FEI, providing compression and dispensing service under a regulated service offering. Section 12B of FEI's General Terms and Conditions of Service approved by Order No. G-14-12, outlines how FEI as a regulated utility will provide this service to customers. This model mitigates declining throughput and supports government policy objectives but does not prevent other providers supplying an unregulated service

2.3 Would FEI characterise NGV compression and dispensing services as an ancillary service to the gas monopoly service?

Response:

FEI would not characterize the CNG/LNG fueling service as an "ancillary service"; nor does FEI consider that CNG/LNG fueling service constitute a new class of service. Rather, FEI believes that CNG/LNG fueling service is part of FEI's existing natural gas class of service and has considered such service as part of the natural gas service dating back to the 1980s when it was first offered to customers.

As articulated in the FEU's final submissions in the AES Inquiry proceeding, three key facts support the above position (see AES Inquiry, FEU Final Submission, paragraph 192, pages 82 – 83):

- *First, NGV fleets are natural gas customers and serving them only makes use of the natural gas delivery system. Other natural gas customers will benefit directly through*

[7] http://www.gov.bc.ca/ener/popt/down/natural_gas_strategy.pdf

decreased delivery rates from the increased throughput associated providing CNG Fueling service.

- *Second, NGV customers pay the same rates for certain components of their bill (for example, the delivery charge and the commodity charge in the case of a CNG customer) as the corresponding natural gas rate classes. The NGV fleet owner will also pay an additional cost associated with compression fueling service..*
- *Third, natural gas is always delivered in usable form. Both compression and dispensing are essential to put the natural gas in a useable form for vehicles. There is no compelling rationale to treat natural gas service to NGVs any differently from natural gas delivery to other commercial customers due to the fact that it must be further compressed or liquefied to make it usable.*

The overall costs and benefits of the CNG fueling service are thus interlinked with natural gas delivery service.

FEI acknowledges that the CNG refueling service can be provided by other non-public utility service providers or the customer itself, who are not subject to the Commission's regulatory oversight; however, FEI believes that its CNG fueling service is an extension of the natural gas system. Further, if and when FEI offers this service to customers, it must offer it according to the GT&Cs that have been approved by the Commission.

Please also see the response to BCUC IR 1.2.3.

2.4 Do NGV compression and dispensing services constitute a new class of service? If not, why not?

Response:

Please see response to BCUC IR 1.2.3.

CNG fueling service, including both compression and dispensing, to provide BFI with fueling service is not a new class of service. It is a natural gas service. The product provided to the customer is natural gas and other natural gas customers will benefit directly through decreased delivery rates from the increased throughput associated providing CNG Fueling service. FEI believes CNG fueling service is an extension of the natural gas system that provides natural gas in a suitable form to meet the customer's needs, and FEI provides the service under an approved Rate Schedule 12B within the natural gas class of service, as was contemplated in the Commission's NGT Decision (Order No. G-128-11, Reasons for Decision).

3.0 CNG MARKET DEVELOPMENT

Reference: Exhibit B-1, Section 2.8, p. 6; Exhibit A2-10, pp. 9. 22; CNG/LNG Service Application, Exhibit B-1, p. 21; Exhibit A2-8, pp. 1-3; Exhibit A2-9, p. 9

FEI states on page 6: "Other policy or business-model information has been explored in other proceedings, namely the regulatory process that established Section 12B of GT&Cs."

In the CNG/LNG Service Proceeding, FEI submitted that it should build the fuelling facilities to "kick-start" the market and that it is uniquely qualified to do so. FEI argued that the market for CNG in BC has stagnated in the past ten years or so, and that it must provide CNG/LNG service as a regulated entity to revitalize the market. It also stated at the time that it "is not aware of other businesses with the expertise and technical capability that have committed to developing the B.C. fuelling station market." (Exhibit A2-10, p. 22)

FEI stated further that: "Over the longer term, TGI's involvement as a market participant promotes the efficient development of natural gas as a transportation fuel, and will help stimulate the market, which does not appear to be gaining any traction without TGI's involvement, while continuing to accommodate other companies that may wish to offer the same service." (CNG/LNG Service Application, Exhibit B-1, p. 21)

In the ongoing FortisBC Energy Utilities Alternative Energy Solutions Inquiry (AES Inquiry), Clean Energy Fuels Corp. (Clean Energy) has submitted that their recent acquisition of the BC-based IMW industries is "very significant in indicating (their) commitment to BC" and brings "their total count of BC and Canadian employees to well over 300 …. Clean Energy recently received $300 million dollars in investment to further build out our existing natural gas fueling infrastructure in North America. While a significant amount of these funds will focus on the development of the first US Natural Gas Highway system, the plans do contemplate extending this network to several Canadian provinces, and specifically along the 1-5 corridor to the Washington - BC border and then in to British Columbia. " (Exhibit A2-8, p. 1-3)

On page 3 of their Evidence in the AES Inquiry, Clean Energy states their belief "that the availability of private and competitively available capital will be sufficient to finance the construction of the needed natural gas vehicle (NGV) refueling infrastructure in North America without regulated utility participation." (Exhibit A2-8, p. 3)

A supporting paper to Clean Energy's evidence states that:

"there is no need for regulated gas utilities to build refueling stations to compete with stations owned by non-utility enterprises. …

Private non-utility enterprises have a strong business incentive to enter the NGV refueling market. The substantial price advantage of natural gas over gasoline and diesel as a transportation fuel provides the profit potential to attract private capital to develop NGVs and the necessary refueling stations….

(T)here is no reason to think that gas utilities are needed to "jumpstart" the NGV refueling market. As explained above, below-cost pricing and other factors will actually discourage the entry of non-utility enterprises into the refueling market. As a result, fewer stations are likely to be built, not more."

(Exhibit A2-8, Covington & Burling White Paper, p. 8)

In their evidence, Ferus LNG states that:

"based on the evidence of significant interest from well 3 established (and financed) industry players, the failure of CNG/LNG programs to develop traction in the past should not lead to the conclusion today that the industry is not viable without artificial aid in the nature of cross-subsidization. The emergence of plans from non-regulated industry players to develop the market is, in fact, strong evidence that the opposite is true." (Exhibit A2-9, p. 9)

Ferus LNG argues further that:

"By artificially attempting to "kick-start" a market through cross-subsidization, there is significant risk that in fact the opposite may occur and markets may actually be stifled."

(Exhibit A2-9, p. 12)

The Panel noted in Order G-128-11 (Exhibit A2-10, Appendix A, p. 9) that "Once the (NGV) market is more mature, FEI states that it may consider other rate designs and business models."

3.1 Based on the statements made in the AES Inquiry by NGV competitors, it appears that there may now be "businesses with the expertise and technical capability that have committed to developing the B.C. fuelling station." Does FEI believe that the market has achieved sufficient maturity to warrant revisiting FEI's business model and rate design at this time? Please discuss.

Response:

FEI believes there is a large difference between claims made by potential competitors and the actual experience in the market. The evidence in the BC market still holds true that FEI is the only market participant that has successfully developed NGV fueling projects in the BC market for the past 10 years. Both AES Inquiry interveners with a competitive interest in providing natural gas fueling services (Clean Energy and Ferus) provided little or no direct evidence[8] of their actual current activities to develop natural gas fueling infrastructure in BC, citing competitive concerns as their basis for non-disclosure (although providing information to the Commission on a confidential basis could have been done).

Attachment 3.1 contains excerpts from the AES Inquiry Exhibit B-12 which includes Clean Energy's Form 10-K and 10-Q filings. To the extent that this question suggests that the recent investment in IMW by Clean Energy indicates market development and maturity, it should be noted that this investment was to acquire a compression equipment manufacturer with an active base of business primarily serving international markets.

From Clean Energy's Form 10-K, at page 13:

> *"Our acquisition of IMW was driven by three desires. First, we wanted to make sure we could satisfy our internal compressor needs, since compressors are the most important piece of equipment for a CNG station. As the adoption of natural gas vehicles has increased, our CNG station construction backlog has increased and our compressor requirements have increased. We believe our compressor needs will continue to grow in the future. By acquiring IMW, we are assured of having compressors readily available to deploy at our stations. The second driver for acquiring IMW was our desire to be able to provide certain customers with a "factory direct" offering. Since some customers do not want our full suite of services and simply want a station that they can own and operate, we can now offer them a high quality and low cost solution. The third driver of the IMW acquisition was our desire to participate in the global growth of natural gas vehicle fueling. In 2010, 32.6% of IMW's sales came from outside of North America, and IMW has a very strong reputation in the global market. As the global market continues to grow, we believe IMW will benefit and participate in such growth."*

As FEI understands it, the 300 employees referenced in the question are not employed to develop the BC market but to manufacture and sell compression equipment. FEI has contributed to the success of the IMW business by awarding approximately $2 million in contracts for station equipment to IMW for projects developed by FEI (including Kelowna School District, Vedder and Waste Management projects).

---

8 In AES Inquiry Exhibit C8-7 BCUC IR 1.2.1, Ferus Inc indicated that it was pursuing, subject to receiving internal approval, the development of an LNG fueling facility in northeastern BC.

It would be very premature to conclude that the market has been "kick-started" through the addition of one project such as the BFI project or even a few projects such as Waste Management, Kelowna School District and Vedder. Even if one were to take the view that the market had been "kick-started", there is no reason to preclude a utility from providing a competitive offering or for the utility to withdraw from providing a competitive service that is desired by customers.

FEI's business model does not prevent other service providers to provide fueling service. Indeed, FEI's model provides a competitive alternative to what other competitors may offer. The customer will select the service provider of the fueling service that best suits its needs. Feedback from BFI regarding the reasons for FEI's success in the competitive process provides an example. BFI selected BFI because FEI has demonstrated ability to:

- provide a full end-to-end service delivering compressed gas into the vehicles;
- build a station within the time line required; and
- have service and support capabilities, including emergency response.

These were major considerations for BFI which is entering into its first NGT operation.

The GT&Cs for CNG/LNG fueling service established by Commission Order No. G-14-12, provide a level playing field for competition, and ensure that FEI does not cross-subsidize NGT offerings and that FEI's activities in this market do not present a barrier to entry by other competing interests.

In the CNG/LNG Service Proceeding FEI did submit that it should build fueling facilities to "kick-start" the market, but at no time did FEI suggest that such offerings would be withdrawn once other competitors entered the competitive marketplace. On the contrary, FEI suggested that the emergence of a viable BC market would likely attract competitors. So far there is evidence that there is interest in precluding the utility from providing the service but no convincing evidence that other service providers have the capabilities to convince customers to adopt NGT in BC.

3.2 If the NGV market is not yet sufficiently developed, how many stations or customers does FEI think would be sufficient to demonstrate that the market has gained "traction"?

Response:

Please refer to the response to BCUC IR 1.3.1.

3.3 Given the statements made by other competitors in the NGV market, is there any need for FEI to construct and own NGV refuelling services?

Response:

Please refer to the response to BCUC IR 1.3.1.

Beyond the response in BCUC IR 1.3.1, FEI believes that several points in the evidence provided by Dr. Ware on behalf of the FEU in the AES Inquiry, included in Attachment 3.3, that are relevant to the question of whether there is need for FEI, as a regulated entity in the field, to be providing natural gas fueling service.

For instance, with regard to a market in which there are only a small number of suppliers, which FEI submits is the case for natural gas refueling, Dr. Ware makes the following comment:

> *"One dimension that needs to more carefully assessed in any particular case, is just how competitive the "competitive" sector is, or is likely to be. With only two or three producers, for example, standard industrial organization economics would generally predict that unregulated producers would still be in possession of some market power."*[9]

A second area which Dr. Ware discusses in the context of thermal energy service, which FEI believes is relevant to the CNG/LNG fueling market being pursued by FEI, is the fact that the competition that exists is largely "competition for the market" rather than "competition in the market".

> *"Other than price competition, important dimensions of competition will be on the margins of promised performance, reliability and innovative service offerings. Much of the competition will take place at the bidding and tender stage, where suppliers of TES projects will tender competing bids (e.g., for projects in hospitals, schools, commercial and residential construction projects). Economists have described such competition as competition "for the market" rather than competition "in the market." The distinction is that in the latter, more conventional case several firms compete in real time to sell*

---

[9] AES Inquiry Exhibit B-25, page 20, Response to BCUC IR 2.12.1

> *products to a given consumer (e.g. the market for automobile purchases) whereas in the former case, the competition is at the bidding stage where firms compete for the right to construct a particular TES facility. Once the winner has been decided, customers will only be offered service by one producer, namely the firm chosen to supply that particular TES market."*[10]

FEI believes that elsewhere Dr. Ware's report supports the notion that if a regulated entity such as FEI is able, without cross-subsidization from gas ratepayers, to bring a cost effective service offering to the natural gas fueling market the participation by FEI "would exert a valuable disciplinary force on the costs of rival suppliers. Rival TES suppliers will be forced to keep their own costs down to a comparable level to FEI in order to win customer contracts."[11]

In summary, the current context in BC of having a very limited penetration of natural gas in the return-to-base fleet market and only a small number of potential natural gas fueling service providers confirms the need and benefit of regulation and having a regulated service provider such as FEI involved in the market.

3.4 Assuming the NGV land market has now gained sufficient momentum, should FEI focus their monopoly resources on demonstrating the use of natural gas in other markets, such as ferries?

Response:

As indicated in BCUC IR1.3.1, FEI does not agree with the assumption that the land market has gained sufficient momentum, nor does FEI agree with the implicit assumption that FEI should withdraw service, to the detriment of customers who desire to receive service from the utility, once a more robust market is established. FEI plays an important role in developing the NGT market, but does not believe its role is limited to acting as an early market development service for other potential suppliers of NGV fueling services. FEI service offering presents an alternative for customers, with the customer deciding whom they contract with for this service.

---

10 AES Inquiry, Exhibit B-19, Attachment B, paragraph 27
11 AES Inquiry, Exhibit B-19, Attachment B, paragraph 16

3.5 If incentives for NGV vehicles were offered, would this not be sufficient to "kickstart" the NGV market? If not, why not?

Response:

Feedback from customers including BFI indicates that they find value and comfort in the utility's ability to offer an end-to-end service model delivering fuel in a useful form to the natural gas vehicle. See also the response to BCUC IR 1.3.1.

Provision of incentives for purchasing NGT is a separate and distinct program that makes it more economically attractive for an early adopter to choose the NGT route. A customer's needs include both the vehicle purchase and a fueling service. Customers must be confident that their needs can be addressed in both areas before they will consider adopting NGT for their business needs.

As stated in the response to BCUC IR 1.10.1, if and when incentives for purchasing NGT are offered again, the incentives would be available to all regardless whether the FEI or another party will be building the fueling station. Thus, If NGT incentives are provided to fleet operators, FEI believes that additional demand for fueling station services will be generated. Having alternative suppliers of CNG fueling service will allow the customers to choose the fueling service that best meets its needs.

3.6 Once the NGV market is established, what does FEI then believe an appropriate role for the gas utility would be?

Response:

Please refer to the response to BCUC IR 1.3.1.

3.7 Once the market has achieved sufficient traction, what are FEI's plans for divestiture?

Response:

Please refer to the responses to BCUC IRs 1.3.1 and 1.3.4. FEI has no plans for divestiture.

3.8 Should GT&C 12B be made interim until the conclusion of the AES Inquiry? Please discuss.

Response:

No. Section 12B of the GT&Cs was the result of an extensive regulatory approval process that allowed input from various stakeholders as well as Commission determination of the final result. The process began on December 1, 2010 and did not finish until February 6, 2012 with the endorsement of GT&Cs 12B. Over this timeframe FEI responded to approximately 500 IR's addressing various parties concerns. FEI believes that the process led to a balanced result that provides FEI and potential customers of this service with a path to develop the NGT market to the benefit of:

- NGT customers, including economic benefits to them and their customers
- All non-bypass FEI customers (through delivery rate reductions)
- The provincial economy (through royalties and economic development)
- The environment (through reductions in GHG emissions and air contaminant reductions)

FEI believes that the established GT&C 12B allows FEI to offer the service to customers on a permanent basis.

See also the response to BCUC IR 1.28.1.

4.0 PROPOSED REGULATORY PROCESS

Reference: Exhibit B-1, Section 2.8, p. 6

FEI states that a reason an expedited process could be appropriate is:" Fourth, underlying policy issues, if any, would have been explored in FortisBC Energy Utilities' Alternative Energy Solutions Inquiry."

4.1 Does FEI believe that approval of this Application is dependent on the AES Inquiry?

Response:

No, FEI does not believe that this Application is dependent on the final decision from the AES Inquiry. As FEI explained in the response to BCSEA IR 1.2.1, in Order No. G-118-11 of the AES Inquiry, the Commission Panel made the following determination:

> *"The Panel agrees that it is not appropriate for this Inquiry to be used as a vehicle to re-open past Decisions of the Commission. With respect to ongoing processes that may have some degree of overlap with the issues being considered by this proceeding, the Panel believes that such processes will be decided on the basis of the evidence put before them. While it may be beneficial to have the outcome of this proceeding known before similar issues are dealt with in other ongoing proceedings, it would be inefficient and potentially unfair for such proceedings to be delayed. The Panel sees the outcome of this proceeding as being applied in a forward looking manner and not impinging on past or current ongoing proceedings."*

This Application is made pursuant to the Commission's previous NGT (CNG-LNG) Decision and the recently approved GT&C 12B. As the Commission Panel has made clear in the above excerpt from the Appendix A to Order No. G-118-11, the AES Inquiry is not intended to re-open or reconsider past Decisions such as the NGT Decision (approved by Order No. G-128-11) or the recent order approving GT&C 12B (Order No. G-14-12). Furthermore, the AES Inquiry is not to delay a proceeding such as this one that is concurrent with the AES Inquiry, and this Application should proceed accordingly.

5.0 GT&C 12B –MINIMUM CONTRACT DEMAND

Reference: Exhibit B-1, Section 3.1 p. 7; Exhibit B-1, Appendix A, 5.3 p. 4; 7.1 (c), p. 7; Exhibit B-1, Appendix B Comparison table

The table in Appendix B of the Application compares GT&C 12B.3 with the conditions of the BFI Canada Inc. (BFI) Agreement:

> "12B.3 Cost of Service Recovery - customers will be charged a "take-or-pay" (i.e. minimum contract demand) under the Service Agreement…"

> "Clause 7.2 The customer agrees to pay a minimum annual service charge based on minimum quantity of 60,000 GJ of CNG being dispensed from the fueling station per year."

12B.3 states in full:

> "12B.3 Cost of Service Recovery - Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the cost of service associated with provision of CNG or LNG Service over the term of the Service Agreement, as calculated pursuant to section 12B.4 <u>where the minimum contract demand stipulated in the Service Agreement is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station</u>." [emphasis added]

FEI states on page 7 of the Application that the "CNG fueling station at BFI's premises is to fuel a return-to-base fleet of 52 waste haulers initially and up to 86 vehicles eventually."

Clause 5.3 of the Fueling Station License and Use Agreement between BFI and FEI (BFI Agreement) specifies that the fueling station must be built to meet the needs of the final number of 86 vehicles.

Clause 7.1 (c) provides that:

> "if more than 5,000 GJ of CNG (the "Base Amount") is dispensed from the Fueling Station in any month, the rate payable for such CNG in excess of the Base Amount shall be the O&M Rate plus fifty percent (50%) of the Capital Rate."

5.1 Please confirm which number was used as the "forecast number of vehicles served by the vehicle fueling station", namely the initial fleet of 52 or the station capacity of 86 vehicles.

Response:

The minimum contract demand of 60,000 GJ per year was based on the initial fleet of 52 vehicles. While BFI may order additional trucks in the future, FEI understands that BFI has only purchased 52 at this time.

At BFI's request, FEI has designed a fueling station which is based on serving up to 86 trucks at a capital cost of approximately $1.9 million. This means that the rate structure of the BFI Agreement is based on the actual capital cost for 86 vehicles and on a minimum contract demand for 52 vehicles. This rate structure allows FEI to fully recover the present value of the cost of service associated with provision of CNG fueling service to BFI over the term of the Agreement.

5.2 How was the base amount of 5,000 GJ per month arrived at?

Response:

The base amount of 5,000 GJ per month, or 60,000 GJ per year, was calculated using a fuel consumption estimate provided by BFI for their fleet of 52 vehicles. Their estimate was approximately 1.5 million diesel litres per year, which divided by a conversion factor of 25.9 results in approximately 58,000 to 60,000 GJs per year.

6.0 CPCN REQUIREMENTS

Reference: Exhibit B-1, Section 3.1, p. 7

"Unlike the usual CPCN applications to build and operate energy infrastructure, the Project is at the request of a customer and will be built to serve this particular customer's need. Since BFI had decided to use CNG trucks for its waste collection services before contacting FEI5, no analysis of alternatives as requested under section 2 of the CPCN Guidelines is necessary."

6.1 Did FEI analyze the alternative of the provision of the refueling station by a non-regulated affiliate or by an independent party that constructs refueling stations such as Clean Energy? (i.e. did FEI analyze whether it was necessary for FEI to provide this service or whether there might be other parties who are capable of providing this service?)

Response:

FEI did not analyze the business models suggested in this question. As further explained in BCUC IRs 1.11.1 and 1.11.2, the customer, BFI, has the prerogative of negotiating with third parties to own, construct and/or operate a refueling station and has made a choice and decision to enter into a contractual arrangement with FEI to provide a regulated service after conducting a competitive bidding process and evaluating proposals it received. In either case – whether BFI contracts with a third party or FEI, FEI would remain the natural gas provider to the fueling station.

Further, since the Commission has approved FEI's GT&Cs for offering this service to customers, there was no need to explore offering this service in a non-regulated affiliate. In FEI's view, the NGT Decision and the resulting GT&Cs set the term and conditions under which FEI can offer this natural gas service to customers.

Please see the response to BCUC IRs 1.11.1 and 1.11.2. Please also see FEI's response to BCUC IR 1.58.1 for further discussion of this topic.

7.0 RECOMMENDED REGULATORY PROCESS AND CPCN GUIDELINES

Reference: Exhibit B-1, Section 2.8, p. 5

FEI states: "Although FEI is structuring this Application, and endeavors to provide all the relevant information, in accordance with the Commission's 2010 Certificates of Public Convenience and Necessity Application Guidelines ("CPCN Guidelines"), FEI does not believe that all requirements of the CPCN Guidelines are applicable to this Application."

7.1 Please provide a summarized list of CPCN Guidelines that FEI has met versus those for which it is applying for exemption or believes do not apply. Please describe the rationale for the categorizations.

Response:

For clarification, FEI is not applying for exemption under section 88 of the UCA from the operation of sections 45 and 46 of the UCA to this Application or to the CNG/LNG Fueling Service in general. Rather, as the statement cited in the preamble indicates, FEI does not believe that all of the requirements or items listed in the CPCN Guidelines are applicable to this Application because of the nature and size of the BFI project. This is consistent with the Commission's statements in Appendix A to Order No. G-50-10 that the Guidelines should be applied in a flexible and reasonable manner. Order No. G-50-10, Appendix A, page 1 states the following when referring to the CPCN Guidelines:

> *"They provide general guidance regarding the Commission's expectations of the information that should be included in CPCN applications while providing the flexibility for an application to reflect the specific circumstances of the applicant, the size and nature of the project, and the issues that it raises. An applicant is expected to apply the guidelines in a flexible and reasonable manner."*

The following table provides the CPCN Guidelines in the left hand column, and the right hand column contains FEI's explanation of where in the application the particular guidelines have been addressed, or if they have not been addressed the reason why.

CPCN Guidelines	Applied (with page or section reference) /Not Applicable (with supporting Rationale)
<u>Applicant</u> (i) Name, address and description of the nature of the applicant's business and all other persons having a direct interest in project ownership or management; (ii) Evidence of the financial and technical capacity of the applicant and other persons involved, if any, to undertake and operate the project; (iii) Name, title and address of the person with whom communication should be made respecting the application; (iv) Name and address of legal counsel for the applicant, if any; (v) Organizational chart of the project team, including the names of the Project Manager and Executive Sponsor for the project; and (vi) Outline of the regulatory process the applicant recommends for the Commission's review of the application, including how persons who were consulted about the project can raise outstanding application-related concerns with the Commission.	See pages 2-6 of the Application.
<u>Project Need, Alternatives and Justification</u> (i) Studies or summary statements identifying the need for the project and confirming the technical, economic and financial feasibility of the project, identifying assumptions, sources of data, and feasible alternatives	The need for, the benefits of and the feasibility of the project are provided in Section 3 of the Application and demonstrated by the terms of the BFI Agreement. The project's revenue requirements and rate impact on customers are described in section 3.3.4 and

CPCN Guidelines	Applied (with page or section reference) /Not Applicable (with supporting Rationale)
considered. The applicant should identify alternatives that it deemed to be not feasible at an early screening stage, and provide the reason(s) why it did not consider them further; (ii) A comparison of the costs, benefits and associated risks of the project and feasible alternatives, including estimates of the value of all of the costs and benefits of each option or, where these costs and benefits are not quantifiable, identification of the cost or benefit that cannot be quantified. Cost estimates used in the economic comparison should have, at a minimum, a Class 4 degree of accuracy as defined in the Advancement of Cost Engineering ("AACE International") Recommended Practice No. 10S-90, Cost Engineering Terminology (May 20, 2009); (iii) A schedule calculating the revenue requirements of the project and feasible alternatives, and the resulting impacts on customer rates; (iv) A schedule calculating the net present values of the incremental cost and benefit cash flows of the project and feasible alternatives, and justification of the length of the term and discount rate used for the calculation; (v) A schedule and supporting discussion comparing the project and feasible alternatives in terms of social and environmental factors, and the applicant's assessment regarding the overall social and environmental impact of the project relative to the overall impact of the feasible alternatives; and	section 5 of the Application. Information relating to FEI's recent long-term resource plan was provided in section 3.4 of the Application. With respect to alternatives analysis, the Project is driven by the fact that BFI was awarded an RFP for municipal waste collection services by the City of Surrey, which stipulated for the use of natural gas trucks for the waste collection services. BFI intends to purchase 52 CNG waste haulers to replace part of its fleet and satisfy the stipulation, and requires CNG fuelling infrastructure and service to meet its obligations to Surrey. As BFI explained in its letter of support filed in this proceeding, it selected FEI through a competitive process, it desires CNG fuelling service and FEI as its provider. As a result, FEI does not believe that alternatives analysis is necessary or appropriate for this application.

CPCN Guidelines	Applied (with page or section reference) /Not Applicable (with supporting Rationale)
(vi) Information relating the project to the applicant's approved long-term resource plan filed pursuant to section 44.1 of the UCA, including the extent to which the project was considered in the plan, and, if applicable, a discussion explaining how the plan provides support and justification for the need for the project.	
<u>Consultation</u> First Nations Consultation Public Consultation (specific Guideline items are omitted)	Because the refueling station is requested by BFI and will be completely built and operated on land owned by BFI, no consultation with First Nations or the public is necessary. Thus, the requirements for describing consultation activities are not applicable.
<u>Project Description</u> (i)Description of the project, its purpose and cost, including engineering design, capacity, location options and preference, safety and reliability considerations, and all ancillary or related facilities that are proposed to be constructed, owned or operated by the applicant; (ii) Outline of the anticipated construction and operation schedule, including critical dates of key events, a chart of major activities showing the critical path (e.g., GANTT2 chart), and the timing of approvals required from other agencies to ensure continued economic viability; (iii) Description of any new or expanded public works, undertakings or infrastructure that will result from or be required by the project, and an estimate of the costs and necessary completion dates;	The description of the project can be found in section 5 of the Application and further details of the refueling station, such as the capacity, location, design specifics, and maintenance and operation, are contained in the BFI Agreement. The key dates for the refueling station installation and operation are contained in section 4.1 of the Application, as is the information regarding further approvals or permits needed from other government agencies or bodies. See section 4.1 of the Application. Human capital resources required for the project are provided in section 2.5 and 4.1 of the Application. Risk analysis, including mitigating factors, is described in section 4.2 of the Application. The Guidelines requirements for a description of potentially new expanded public works and identification and preliminary assessment of potential effects of the project on the physical, biological and social environments or on potentially affected First Nations and the public

CPCN Guidelines	Applied (with page or section reference) /Not Applicable (with supporting Rationale)
(iv) Human capital resources required to undertake the project; (v) Risk analysis identifying all significant risks to successful completion of the project, including an assessment of the probability of each risk occurring, and the consequences and the cost to mitigate the risk; (vi) Identification and preliminary assessment of potential effects of the project on the physical, biological and social environments or on potentially affected 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; (vii) Identification of the customers to be served by the project and, where the project would expand the area served by the applicant, a geographical description of the expanded service area; (viii) List of all required federal, provincial and municipal approvals, permits, licenses or authorizations; and (ix) Summary of the material conditions that are anticipated in federal, provincial and municipal approvals and confirmation that the costs of complying with these conditions are included in the cost estimate in the application.	are not applicable for this Application as the project will be built and operated within the limits of BFI's premises. Similarly, the Guidelines requirement for identification and description of customers and service areas to be served by the project is not applicable in this Application. The project is to serve BFI on BFI's premises.
<u>Project Cost Estimate</u> (i) Project cost estimate, including a description of the method of estimating used, the percentage of engineering completed at the time of the estimate,	Information relating to the project cost estimate is provided in sections 5.1 and 5.2 of the Application, including the specific information expected by the Guidelines such as contingency amount,

CPCN Guidelines	Applied (with page or section reference) /Not Applicable (with supporting Rationale)
and identification and justification of all assumptions, exclusions, inflation and discount factors, and sources of benchmarks and other data; (ii) The cost estimate should be stated in nominal as well as real dollars, identify an expected accuracy range and have, at a minimum, a Class 3 degree of accuracy as defined in AACE International Recommended Practice No. 10S-90, Cost Engineering Terminology (May 20, 2009); (iii) The cost estimate should provide: (a) Any funds spent in prior years attributable to the project; (b) A list of all project direct and indirect costs using a work breakdown structure by year until completion; (c) Escalation (including inflation) amounts; (d) Contingency amount; (e) Interest during construction or allowance for funds used during construction and corporate overhead; (f) Identification and explanation of any management or other reserves; (g) Any legal, regulatory and other non-project costs, including costs associated with First Nations and public consultation and accommodation. (iv) Identification of any cost items not included in the estimate, including transportation costs, and the reason for the exclusion; and	breakdown of cost components, and AFUDC. Present value of revenue requirements for the project and the discounted cash flow analysis are provided in the supporting financial schedules. Section 5.3.3 of the Application provides information on overhead applicable to the project. .

CPCN Guidelines	Applied (with page or section reference) /Not Applicable (with supporting Rationale)
(v) If a Monte Carlo analysis was used to model and back-up the amount of project contingency included in the cost estimate, the base estimate, P50 expected value estimate, P90 estimate, histogram and cumulative curves, and tornado graphs.	
<u>Provincial Government Energy Objectives and Policy Considerations</u> (i) Discuss how the project is consistent with and will advance the government's energy objectives as set out in the UCA. If the nature of the project precludes a direct link to the energy objectives, the application should discuss how the project does not hamper other projects or initiatives undertaken by the applicant or others, from advancing these energy objectives; (ii) Discuss how the project relates to and supports the Province's electricity self-sufficiency goals as set out in 64.01 of the UCA or as set out in Special Direction No. 10 to the Commission, if applicable; and (iii) Where the applicant is BC Hydro or a prescribed public utility, discuss how the project relates to and supports the Province's clean and renewable electricity goal as set out in 64.02 of the UCA, if applicable.	Discussion of applicable provincial government energy objectives is found in section 3.2.2. The other two items are not applicable to this Application.
<u>New Service Areas</u> (i) Telephone number or other means by which customers will be able to contact the utility, particularly regarding an emergency; (ii) Description of facilities and trained personnel that will provide	As explained on page 5 of the Application, the application does not open up new service areas. It offers CNG refueling service to a customer of FEI. Thus, the items listed in the Guidelines in this regard will not be applicable to this Application. The service agreement with BFI lists the contact information/personnel for the service provided. (See page 5 of the

CPCN Guidelines	Applied (with page or section reference) /Not Applicable (with supporting Rationale)
emergency response; (iii) Tariff including terms and conditions of service, rate schedules and initial rates the applicant proposes for customers in the new service area; and (iv) Information confirming the proposed rates will be competitive with other service options that are available to customers in the new service area.	Application.) The BFI Agreement provides the terms and conditions of service, including rates to be charged. Section 5.3 provides information on the rate design, demonstrating FEI's full compliance with Commission approved section 12B of FEI's General Terms and Conditions.

FEI states that: "Thus, FEI has not included in the Application any discussion on public and First Nations consultation."

7.2 Please describe any public consultation with neighbouring businesses and the City of Coquitlam that has occurred.

Response:

There has been no consultation with neighbouring businesses, nor does FEI believe the consultation is required. BFI has an existing base of business operating garbage trucks from the Fawcett Road location. The operation of CNG powered trucks versus diesel trucks does not change significantly the impact on neighbours other than reduction of noises from the trucks.

Consultations with the City of Coquitlam have been initiated regarding construction permits for the facility. No civil permitting is required and the site is zoned to permit construction of the fueling facility.

FEI states: "Nor has FEI identified and assessed potential effects of the Project on First Nations and the general public in terms of physical, social or biological environment (see CPCN Guidelines section 4(vi))."

7.3 Is FEI of the view that CPCN Guidelines section 4 (vi) does not apply or that it has been met?

Response:

What FEI is saying in the referenced text is that section 4(vi) of the Guidelines do not apply as the fueling station will be built completely within the limits of BFI's private property. The quote, in its entire context, reads as follows:

> *"As the refueling station will be completely built and operated on BFI's premises and its installation and operation will have little potential effect on First Nations and the public, there is no need for public or First Nations consultation. Thus, FEI has not included in the Application any discussion on public and First Nations consultation. Nor has FEI identified and assessed potential effects of the Project on First Nations and the general public in terms of physical, social or biological environment (see CPCN Guidelines section 4(vi)). This is consistent with what was done for Waste Management.*[4]"

See also response to BCUC IR 1.7.1, 1.7.2 and the NGT Application, Section 7.4 at page 69.

8.0 CPCN GUIDELINES

Reference: Exhibit B-1, Section 2.8, p. 5

Section 4 of the CPCN Guidelines requires the "engineering design, capacity, location options and preference, safety and reliability considerations, and all ancillary or related facilities that are proposed to be constructed, owned or operated by the applicant".

8.1 Describe the capacity of the fueling station.

Response:

After discussions with BFI, FEI was directed to build a station with sufficient capacity to fuel 86 vehicles using a time fill fueling approach with fuel being delivered to the vehicles overnight. This is the maximum number of vehicles that can be accommodated on the existing site given other operational needs. The station will have 86 fill posts and will have three compressors. This provides capacity to service the initial fleet of 52 trucks plus additional capacity to fuel additional CNG trucks that BFI may acquire in the future.

8.2 Will FEI be providing any ancillary or related facilities for BFI besides those described in the Application?

Response:

At this point in time, FEI does not expect to be providing any ancillary or related services for BFI besides those described in the Application and agreed to in the Fueling Station Licence and Use Agreement.

9.0 CONSISTENT WITH FEI'S MOST RECENT LONG-TERM RESOURCES PLAN

Reference: Exhibit B-1, Section 3.4, pp. 11-12 and Appendix D

FEI states: "The BFI Project is consistent with the 2010 Long Term Resource Plan ("LTRP") filed by the FortisBC Energy Utilities ("FEU," which includes FEI, FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc). At page 58, the FEU described its intention to advance its NGT initiatives over the coming years:

> "The Utilities see the development of new NGV services, programs and markets as a key part of its low carbon strategy to help meet both the changing needs of our customers and the GHG reduction targets legislated by the Province.
>
> The BFI Project represents another step toward advancing its low carbon strategy."

9.1 Please provide an update on other CNG/LNG Service projects such as the Kelowna School District and the results of the most recent economic tests (CS Test).

Response:

FEI intends to file CPCN applications for an LNG fueling station for Vedder Transport and a CNG fueling station for Central Okanagan School District No. 23 ("Kelowna School District" or "KSD") in the coming months. FEI is currently drafting the CPCN Applications for both these projects. FEI does not have any updated economic tests for KSD at this time. The details on these projects, including the economic benefits and impacts, will be provided in the CPCN applications.

10.0 PROJECT NEED AND JUSTIFICATION

Reference: Exhibit B-1, Section 3.1, p. 7

"In December of 2011, BFI was awarded an RFP for municipal waste collection services by the City of Surrey, which stipulated for the use of natural gas trucks for the collection services. BFI intends to purchase 52 CNG waste haulers to replace part of its fleet and satisfy the stipulation. Future fleet additions could bring their total number of CNG trucks to around 86 at the Coquitlam facility."

10.1 Has BFI made or has FEI received an application for Energy Efficiency and Conservation (EEC) incentive funding related to this project?

Response:

This response answers BCUC IRs 1.10.1 through 1.10.6.

In accordance with Commission Order No. G-145-11, which determined that the EEC incentive funding for NGV program is not a demand-side measure within the meaning of the *Clean Energy Act* or *the Utilities Commission Act*, FEI has discontinued the use of EEC funding for its NGV program,.

Since the above mentioned decision, FEI has not solicited or received applications for EEC incentive funding from BFI or any other parties relating to this Project or the NGV program; nor has the Company committed any EEC incentive funding or other funding to BFI or any other parties for the purposes of purchasing CNG/LNG trucks or using a low-carbon fuel switching application.

10.2 What assumptions have been made related to EEC funding?

Response:

Please see our response to BCUC IR 1.10.1.

10.3 Please provide the total amount of incentive funding for low-carbon fuel switching applied for by BFI.

Response:

Please see our response to BCUC IR 1.10.1.

10.4 Has FEI made any commitments to BFI to provide EEC incentives or any other incentives for the purchase of these trucks?

Response:

Please refer to the response to BCUC IR 1.10.1.

10.5 If so, please describe the nature of the commitment including the total amount of incentive funding committed.

Response:

Please see our response to BCUC IR 1.10.1.

10.6 If EEC incentives are to be made available to BFI from FEI, would these incentives be available to BFI regardless whether FEI or another party built the refuelling station?

Response:

Please see our response to BCUC IR 1.10.1.

11.0 PROJECT NEED AND JUSTIFICATION

Reference: Exhibit A2-7, p. 6

"The RFP document required the waste collection fleet to be powered by Compressed Natural Gas (CNG) from the outset of the contract term. "

11.1 Given the City of Surrey stipulated the use of natural gas trucks for its municipal waste collection services in its Request for Proposals (RFP) on providing waste collection services, is FEI aware of any other parties that have expressed an interest in installing and operating the CNG refuelling station to either the City of Surrey, to FEI or to any of the parties that responded to the City of Surrey's RFP?

Response:

As FEI understands it, several bidders submitted proposals to the City of Surrey for the waste collection services contract. Contacted by several parties participating in the bid, FEI provided budget proposals to them to assist them in developing their proposals. This included preliminary assessment of a variety of sites to determine their suitability from a gas supply perspective as well as general advice regarding the design and budget cost of the station. FEI was not privy to any of the any of the proposals that were submitted to the City of Surrey, but believes that several bidders offered proposals that would involve the bidder arranging for construction of the fueling facility at the bidders' proposed site.

FEI is aware that Clean Energy had offered to build the fueling station for BFI through BFI's competitive bidding process.

11.2 Given the City of Surrey has stipulated the use of natural gas fuelled trucks for its municipal waste collection services, why is it necessary for FEI to install and operate the fuelling station?

Response:

FEI understands that the City of Surrey's bid document requested bidders to supply proposals under two different alternatives. One was the situation where the fueling service would be provided by the City of Surrey and the other was where the proponents arranged for their own fueling service. The City of Surrey subsequently awarded BFI with the contract where BFI would provide the fueling station for its vehicles. FEI is not aware of the exact reasons why the City of Surrey chose this alternative as FEI was not part of this selection process.

Under the scenarios described above, either the City of Surrey or the successful bidder would need to arrange for fueling service.

BFI was awarded the waste collection services. The fueling station it needs could have been installed and operated by another party or built, owned and operated by BFI itself, but BFI evaluated all proposals and decided that FEI is best qualified and capable of meeting BFI's requirements and that the business model offered by FEI was more preferable. FEI has demonstrated its ability to build a station meeting Canadian codes and standards within the project timeline. (See also the response to BCUC IR 1.3.1.) Thus, it is necessary for FEI to install and operate the fueling station as BFI made a choice to award the fueling station construction and operation to FEI.

11.2.1 Would the City of Surrey stipulation not have had the effect of ensuring a refuelling station would have been constructed regardless whether it was FEI or another party? If FEI disagrees, please explain.

Response:

As FEI understands it, the stipulation that the waste collection fleet be powered by CNG was a decision made by the City of Surrey after consultations with industry participants over the past two years. FEI participated in that consultation process by providing information regarding the economic and environmental benefits of CNG vehicles versus diesel vehicles As indicated in Exhibit A2-7, the City of Surrey decided to use CNG powered trucks to achieve several objectives.

Once the request for proposals was issued, it is probable that the bidders would have developed some form of solution for the City of Surrey without FEI's participation; however, the fact that BFI was awarded the contract, and, in turn, BFI contracted with FEI to construct the fueling station after a competitive process indicates that BFI preferred the solution FEI offered over the ones offered by other potential service providers.

Had FEI not participated in the competitive process to supply BFI with fueling services, BFI would have been limited in their options. This would likely result in higher end costs for BFI.

12.0 PROJECT NEED AND JUSTIFICATION

Reference: Exhibit B-1, Section 3.1, p. 7

"To serve its new fleet of CNG waste haulers, BFI contacted FEI, wishing to have FEI supply, install and maintain a CNG fuelling station on BFI's premises to fulfil their RFP obligation to City of Surrey."

12.1 To FEI's knowledge, did BFI contact any other party with regard to installing and maintaining a CNG fuelling station?

Response:

Yes, BFI solicited competitive bids for the fueling station. BFI awarded the fueling station to FEI after assessing other proposals.

12.2 To FEI's knowledge, did any other party approach BFI with regard to installing and maintaining the CNG fuelling station?

Response:

As stated in response to BCUC IR 1.12.1, other parties responded to BFI's solicitation for bids. But, FEI is not aware whether other parties initiated contact with regard to installing and maintaining the fueling station.

12.3 Did BFI put out any requests for competitive bids for the CNG refuelling station?

Response:

Please refer to the response to BCUC IR 1.12.1.

13.0 BENEFITS OF PROJECT

Reference: Exhibit B-1, Section 3.1, p. 8

"FEI understands that the City of Surrey required CNG trucks for its collection service as a way to reduce its collection service cost through potential savings on fuel cost."

13.1 How does the incremental capital cost of a natural gas fuelled truck versus a traditional diesel powered truck impact the cost of the collection service to City of Surrey?

Response:

The capital cost of a CNG fueled garbage truck is approximately $40k higher than the cost of a diesel truck. In addition, there may be certain other upfront costs associated with maintenance and facility upgrades for CNG vehicles. FEI is not privy to the actual cost of the vehicles or the other costs involved in order to provide the waste collection services to the City of Surrey. In general these higher initial costs are offset over time through lower operating costs, including savings on fuel costs.

FEI is not privy to how the actual cost of the vehicles and the other costs are translated to service costs to the City of Surrey in the contract between BFI and the City for Surrey for the waste collection services, and thus does not have sufficient information to estimate the net impact on the costs of collection for the City of Surrey.

While FEI cannot isolate the exact impact of the switch to CNG service on the final contract costs for the City of Surrey from other factors involved in its final agreement with BFI, FEI notes that the City of Surrey has indicated that the cost of this contract is substantially less than the previous contract which utilized diesel vehicles.

> *"The City is currently paying $12.3 million per year for waste collection services under a contract with Emterra. BFI's proposal represents a savings to the City solid waste utility of approximately $2.8 million per year for collection services."*[12]

13.1.1 Would these costs be a component of BFI's cost to provide the collection service? If not, please explain.

---

[12] See Surrey Corporate Report - Exhibit A2-7, Page 10

Response:

Although FEI assisted in providing some information in BFI's preparation for its response to the RFP of the City of Surrey, FEI was not a party to the development of BFI's bid or contract for the City of Surrey collection service. It is, however, reasonable to assume that both the higher initial costs and the lower operating costs, including lower fuel costs, would be factored into the pricing for this bid. As shown in Exhibit A2-7, BFI's annual price for service to the City of Surrey is $9,505,923, about $2 million less than the next bidder.

FEI estimates BFI's fuel cost reductions would be $1.23 million per year. If BFI's incremental capital cost for the vehicles is $40k per vehicle, this would total to $2.1 million; hence the payback of the incremental cost would be approximately 2 years.

As shown in Exhibit A2-7, the City of Surrey had several objectives, including performance of the collection service in a cost effective manner and reduction of adverse environmental impacts. By choosing BFI, the City stated that "In addition to providing the lowest price for the recommended service option, BFI also submitted the lowest price bid in comparison to the proposals from the other proponents for all of the combination of services or service-delivery options articulated in the RFP."

Given that BFI had the most competitive and winning bid, it can be reasonably assumed that the City of Surrey chose BFI because its proposal for the collection services best suits the City's financial and environmental objectives and best serves the interests of the citizens of the City of Surrey as part of the fuel cost reductions may potentially be passed on to its residents. FEI thus believes that the City's choice of BFI's project demonstrates and supports that the BFI's project will serve the interests of its citizens.

13.1.2 To what extent would the incremental capital costs of the NGV trucks offset the savings on fuel costs over the 7 year term of the BFI Agreement?

Response:

Please refer to the response to BCUC IR 1.13.1.

14.0 MONETIZATION OF CARBON CREDITS

Reference: Exhibit A2-10, p. 29; Exhibit B-1, Section 3.3.2, p. 9

"The Panel is of the view that carbon has a value and that value should be determined and recognized. **The Panel therefore directs FEI to quantify the GHG reductions and potential for carbon credits in future applications and describe any steps that have been taken by the parties to monetize those potential benefits."** (Exhibit A2-10, p. 29)

"Any potential GHG emission reduction offsets generated by the operation of these CNG trucks will flow to BFI. It is FEI's understanding that BFI is obligated to pass these benefits to the City of Surrey as part of their RFP requirement." (Exhibit B-1, p. 9)

14.1 In accordance with the CNG/LNG Service Decision, please "quantify the GHG reductions and potential for carbon credits in the Application and describe any steps that have been taken by the parties to monetize those potential benefits".

Response:

FEI has quantified the GHG reductions and has estimated that there is a reduction of 419 tonnes per year from the switch to CNG powered trucks.

FEI has taken no steps to monetize the GHG reductions as FEI believes that the reduction benefits belong to either Surrey or BFI depending on the nature of their agreements to which FEI is not party to. FEI has no basis to make a claim on the monetary value of any environmental attributes.

In circumstances where FEI provides incentives to assist operators in acquiring natural gas powered vehicles, FEI may have a different negotiating position and may in some cases make a reasonable claim to acquire ownership of environmental credits. This was not the case with respect to the BFI Agreement as no incentives were provided.

14.2 Does the determination of the fuelling charge include any financial adjustment related to the benefits of the GHG emissions reductions flowing to BFI? If so, please describe. If not, why not?

Response:

No. The City of Surrey has taken the step of mandating the switch to CNG fueled trucks. It is BFI that is investing in the vehicles and assuming the risk of converting to CNG operations. The environmental attributes are created by these actions. Thus, the associated benefit stream is not included in FEI’s Cost of Service for providing the fueling service.

15.0 GREENHOUSE GAS EMISSIONS

Reference: Exhibit B-1, Section 3.3.2, p. 8

15.1 What is the annual natural gas consumption in gigajoules (GJ) for a BFI truck travelling 23,400 km per year?

Response:

The average annual distance of 23,400 km per year estimate that was provided by BFI is based upon their requirement to service the City of Surrey contract and is derived from diesel trucks which provided a similar service.

Since the CNG trucks have not yet begun service, FEI does not have a direct conversion from GJ to km; however, FEI's best estimate is between 1,000 GJ and 1,500 GJ per truck. This conversion will depend up BFI's fuel management strategy as well as the actual natural gas engine efficiency. However, the minimum contract demand from the BFI Agreement of 60,000 GJ results in 1,153 GJs per truck.

16.0 ECONOMIC BENEFITS TO THE PROVINCE

Reference: Exhibit B-1, Section 3.3.3, p. 9

16.1 What assumptions were made regarding the market price of gas in arriving at the assumed flow through value of $0.50 per GJ to quantify the revenue benefits to the Province's royalty programs?

Response:

The royalty structure for natural gas production in BC is complex and varied. FEI has relied on feedback from Ministry of Energy staffers that $0.50/GJ is a reasonable average estimate of the royalty benefit to the Province from natural gas production in BC.

17.0 DELIVERY MARGIN BENEFITS

Reference: Exhibit B-1, Section 3.3.4, p. 11

17.1 How is the "monthly peak day" estimate of 205 GJ arrived at in Table 3?

Response:

The monthly peak day estimate in Table 3 is the same as the Daily Demand calculation in Rate Schedule 5 and 25. The Daily Demand calculation is equal to 1.25 multiplied by the greater of:

(a) the Customer's highest average daily consumption of any month during the winter period (November 1 to March 31), or

(b) one half of the Customer's highest average daily consumption of any month during the summer period (April 1 to October 31).

The calculation of Daily Demand will be based on the Customer's actual gas use during the preceding Contract Year.

Since this is a new customer, the monthly consumption was estimated. Being in the transportation sector this customer would not be a heat sensitive customer and therefore would have a very flat and consistent load profile.

	30	31	31	28	31	30	31	30	31	31	30	31	365
	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Monthly GJ's	4,932	5,096	5,096	4,603	5,096	4,932	5,096	4,932	5,096	5,096	4,932	5,096	60,000
Avg Daily GJ's	164	164	164	164	164	82	82	82	82	82	82	82	

Daily Demand of 205 GJ =164 GJ (Max Avg Daily GJ's) x 1.25

After the customer has completed a full Contract Year (November 1 to October 31), the calculation of daily demand is reviewed and adjusted every January 1st as per terms and conditions of rate schedule 5 or 25 based upon the customer's actual gas use during the preceding Contract Year.

17.2 Does BFI operate the trucks on weekends and holidays?

Response:

This response also answers BCUC IR 1.17.2.1.

FEI does not have a copy of the executed contract between BFI and City of Surrey. However based on Appendix 5 – Draft Contract of the RFP issued by the City of Surrey on June 6, 2011, FEI believes that BFI will operate Monday – Friday and perform regular collection on all holidays, expect for Christmas Day and New Year's Day. Based on this requirement, FEI believes each truck would be in operation five days a week.

17.2.1 How many days per week is each truck in operation?

Response:

Please see our response to BCUC IR 1.17.1.

17.3 What is the maximum daily fuelling capacity requirement, expressed in gigajoules, for 52 trucks?

Response:

This response also answers BCUC IR 1.17.4.

BFI has not provided FEI a maximum daily fueling capacity requirement for 52 or 86 trucks. Although FEI believes the BFI will operate its trucks approximately five days a week, BFI may also consume natural gas over the weekends due to intermittent fueling intervals or maintenance schedules.

Regardless, the customer's maximum daily fueling capacity requirement is not constrained by the monthly peak day estimate. The calculation of the monthly peak day (as explained in BCUC IR 1.17.1) is the Daily Demand calculation in Rate Schedule 5 and 25. Even though BFI's daily requirement (i.e. 60,000 / 260 days = 231 GJ/day) will likely exceed the peak day (205 GJ), the two values are independent of each other.

17.4 What is the maximum daily fuelling capacity requirement, expressed in gigajoules, for 86 trucks?

Response:

Please see our response to BCUC IR 1.17.4.

18.0 TECHNICAL CAPABILITY

Reference: Exhibit B-1, Section 2.4, p. 3

18.1 Describe the qualifications and experience of Jenmar Concepts Inc. with regard to the design and construction of natural gas refuelling stations.

Response:

Jenmar Concepts Inc. has over 20 years of experience in design engineering for CNG stations as well as H2 and HCNG stations and has a total of 6 staff members.

Jenmar has a Master Services Agreement with FortisBC which prescribes agreed charge out rates for various levels of engineering and engineering related activities. Thus, FEI does not have the need to go out for competitive bids for engineering services on a project by project basis. Jenmar’s rates are compared to rates for other engineering contractors used by FEI’s Project Management Office under Master Services Agreements and this process ensures that the rates are competitive.

Jenmar has been involved in FortisBC’s NGV projects since 2009. Projects that they have contributed to include Kelowna School District, Waste Management, Vedder, and BFI.

18.1.1 For how many years and in what capacity has FEI engaged the services of Jenmar Concepts Inc.?

Response:

Please refer to the response to BCUC IR 1.18.1.

18.1.2 Did FEI engage a competitive bid process to select Jenmar Concepts Inc. for the BFI project?

Response:

Please refer to the response to BCUC IR 1.18.1.

19.0 FUELING STATION SPECIFICATIONS

Reference: Exhibit B-1, Appendix A, Section 5.3, p. 4

"FEI shall supply a Fuelling Station of a size and with such other specifications as reasonably determined by FEI to be suitable to accommodate the servicing of up to 86 Vehicles based on information provided by the Customer, including its demand profile."

19.1 Please provide a copy of the demand profile provided by BFI.

Response:

BFI has not provided FEI with a detailed demand profile; rather, it has provided an estimate of their annual fuel consumption based on diesel trucks. This value, approximately 1.5 million diesel litres, results in approximately 60,000 GJs per year. FEI has assumed their fuel consumption will be relatively flat throughout the year, which is consistent with Waste Management's actual fuel consumption throughout 2011.

As explained in BCUC IR 1.17.1, FEI has calculated the customer's daily demand using the terms under Rate Schedule 5 and 25. After BFI has completed a full contract year, the calculation of their daily demand will be reviewed and adjusted (as per the terms and conditions of Rate Schedule 5 and 25) based on the customer's actual gas use during the preceding contract year.

The customer's fueling charge is not set using the daily demand estimate. With respect to volume, it is dependent upon the customer's fueling consumption estimate and the customer's commercially desired volume commitment.

19.2 What is the maximum daily quantity the fuelling station will be designed to dispense?

Response:

The maximum daily quantity of gas the fueling station can dispense will depend upon the suction pressure available from the gas main and compressor selected. Based on an estimate provided by Jenmar Concepts, the maximum gas that can be dispensed with the existing 2" gas main is 372,000 scf/day, which is equivalent to approximately 365 GJ per day. This could service up to 86 trucks with a 10 hour fueling period.

19.3 Will the BFI CNG trucks be in operation 7 days a week or 5 days a week to fulfill the contract with the City of Surrey? (i.e. Does BFI's contract with the City of Surrey require waste to be collected on weekends and holidays?)

Response:

Please see our response to BCUC IR 1.17.2.

FEI believes BFI will operate its trucks five days per week to fulfill the contract with the City of Surrey.

20.0 PROJECT CAPITAL COSTS

Reference: Exhibit B-1, Section 4.1, p. 13

"The CNG fueling station to be installed on BFI's premises will be capable of fueling up to 86 trucks in its current design. FEI believes that BFI will only purchase 52 trucks at this time. If BFI decides to purchase vehicles beyond 52 (up to 86) vehicles, no significant capital investments would be required"

20.1 Will the station being designed and installed for the October 1, 2012 in service date be fully capable of fuelling 86 trucks?

Response:

This response also includes answers to BCUC IRs 1.20.1.1 and 1.20.1.2.

The CNG fueling station will be fully capable of fueling up to 86 trucks when going to service on October 1, 2012. As specified in section 5.3 of the BFI Agreement, the station is designed to be suitable to accommodate the servicing up to 86 vehicles. This design provides BFI the flexibility to rotate their trucks in alternate parking stalls for operational purposes.

No additional capital requirements are required to service 86 trucks within the scope of this Project.

20.1.1 If not, what additional capital investments would be required?

Response:

Please see our response to BCUC IR 1.20.1.

20.1.2 To the extent additional capital investments are required to serve 86 trucks, what are the incremental capital costs and how will the associated incremental capital costs be recovered from BFI?

Response:

Please see the response to BCUC IR 1.20.1.

21.0 PROJECT CAPITAL COSTS

Reference: Exhibit B-1, Section 4.1, p. 13

"At this time, FEI has not purchased any equipment for this Project, but intends to conduct an RFP for the procurement of key CNG equipment components over the coming weeks. FEI anticipates the RFP would close by mid-March, with contract awards following thereafter."

21.1 To the extent FEI has received RFP submissions on key equipment, please provide an updated estimate of the capital cost for the project.

Response:

FEI's RFP for CNG equipment closes on March 30, 2012. FEI has not yet received any submissions from proponents at the time of this filing was prepared. Thus the capital cost estimate for the project has not changed from the $1.9 million detailed on page 15 of Exhibit B-1.

22.0 PROJECT CAPITAL COSTS

Reference: Exhibit B-1, Section 5.1, p. 15

22.1 Please add an additional column to "Table 4: BFI CNG Fueling Station Capital Expenditures" and populate it with the final costs for each of the equivalent components of the Waste Management of Canada Corporation (WM) refuelling station.

Response:

FEI has added the additional column as requested in the revised Table 4 below.

Item	**BFI Forecast Cost**	**WM Actual Cost**
CNG Storage and Dispensing Equipment	$ 770,531	$ 503,181
Civil, Structural Work	$ 401,440	$ 127,476
Mechanical and Field Piping	$ 210,635	$ 47,923
Electrical Work and Service	$ 93,331	$ 50,734
Equipment Shipping	$ 15,700	$ 9,275
FortisBC Engineering, Project Management, Commissioning	$ 199,875	$ 36,442
Subtotal	$ 1,691,512	$ 775,031
Contingency	10%	0%
Total with Contingency	**$ 1,860,663**	**$ 775,031**
Add AFUDC	$ 24,596	$ 13,316
Total Expenditures	**$ 1,885,259**	**$ 788,347**

The comparison between Waste Management's CNG fueling station and the proposed BFI CNG fueling station is not an equivalent one due to each customer's fuel demand requirements, customer operational practices, and the physical geography of the property.

The Waste Management station was designed to serve 20 vehicles and is currently dispensing approximately 30,000 GJ per year. BFI is designed to serve up to 86 vehicles, or approximately 100,000 GJ of load (60,000 GJ / 52 trucks = 1,153 GJ per truck).

Dividing the total capital expenditure by the fueling station's capacity provides a reasonable means to compare capital expenditures (in $ of capital per GJ) for these two projects. The table below summarizes this comparison.

Description	BFI Forecast	WM Actual	WM Forecast with capital additions
Vehicle Capacity	86	20	40
Fuel Consumption Estimate (GJ)	100,000	30,000	60,000
Total Capital Expenditures	$1,885,259	$788,347	$920,000
Capital per GJ	$18.85	$26.28	$15.33

This comparison shows that the proposed BFI fueling station, on dollars of capital per GJ/yr, is below the actual capital of the existing Waste Management station. The existing CNG compressor at the WM facility has capacity to fuel an additional 20 to 30 trucks if desired, (depending upon fuel demand) with incremental capital requirements. The third column shows this scenario with a forecast capital addition of approximately $130,000[13] to serve an additional 20 trucks at WM's facility.

Based on this analysis, the capital requirements for BFI are reasonable as they fall between the 'capital per GJ" of WM's existing fueling station and the potential cost of WM's expanded station (if desired by WM).

Other factors which are not easily quantifiable, such as property limitations or the customer's operational requirements, also affect the station design, and subsequently the overall capital expenditure. While there may be commonality with respect to some equipment components, each fueling station FEI installs and constructs will likely differ in its design and capital cost.

[13] From the CNG/LNG Application proceeding, BCUC IR 2.1.7 states $79,400 for protection posts and an inductive voltage survey will be included in future expansion at WM's facility. At this time FEI also estimates additional fueling hoses (20 @ $2,000 per, plus install) will be required. This incremental cost is a preliminary estimate only.

23.0 PROJECT CAPITAL COSTS

Reference: Exhibit B-1, Section 5.1, p. 15; Section 3.3.4, p. 11

"Using a variance range of plus or minus 2 percent for amendments to the fueling service rate is appropriate because it equates to approximately $37,000 of the total capital costs, which has a minimal impact of $0.07/GJ on the contract rate and has not impact on the delivery rates for natural gas customers.14"

23.1 Does FEI agree that $37,000 in potential cost overruns would represent a significant portion (44%) of the $84,000 of incremental delivery margin revenue benefits that FEI estimates will flow assuming BFI takes delivery of the gas under Rate Schedule 25, all else being equal?

Response:

The potential cost variance of up to $37,000 represents the maximum cost differential, positive or negative, which could occur without amendments to the BFI Agreement. Thus, the incremental delivery margin revenue benefit would be reduced by up to $37,000 if cost overruns occur, or conversely, increased by up to $37,000 if the project is completed under budget.

The comparison to delivery revenue margin should be expressed over the term of the BFI Agreement, which calculates to approximately $483,000 ($84,000 x 5.75 yrs = $483,000, please note that 5.75 years, rather than 7 years is used for the determination of the total benefit, taking into consideration the fact that the BFI delivery margin recoveries will not be included as a reduction to the delivery rates of non-bypass customers until the next revenue requirement application). Thus, FEI does not agree the $37,000 potential cost differential (positive or negative) represents a significant portion (8%) of the delivery revenue margin benefit ($37,000 / $483,000 = 8%). Whether the variance is positive or negative, the overall impact of cost variances on delivery rates for natural gas customers is minimal, and the impact of the project overall on delivery rates is favourable.

24.0 FUELING STATION LICENCE AND USE AGREEMENT – RENEWAL TERMS

Reference: Exhibit B-1, Appendix A, p. 2; Exhibit A2-6, Tariff Supplement J-1, p. 1

24.1 Please confirm that term of the BFI Agreement is renewable at the option of the customer rather than FEI and that FEI does not have the contractual right to request a renewal of the BFI Agreement.

Response:

Confirmed. The customer must request renewal of the BFI Agreement six months prior to expiry with written notice. Sections 11.1 of the Agreement sets forth the terms for payment by BFI at the end of the initial term of the contract or prior to the 20 year anniversary of the effective date of the contract.

24.2 Given that FEI has the right to renew the WM Agreement under Section 1.2, explain why the renewal options for the two CNG Service agreements are not the same.

Response:

The WM Agreement is structured somewhat differently because WM had concerns and issues somewhat different from BFI. However, in each case, the parties reached mutually agreeable terms, with each party being satisfied that the terms and conditions met their respective needs.

Because each customer's operational needs may differ, having completely identical agreements would not be practical, and would not be in the customer's or FEI's best interests. FEI's focus in BFI's negotiation and agreement was to ensure that the terms and conditions fulfilled all the requirements of GT&C 12B as approved by the Commission. FEI believes that the BFI agreement fulfills all these requirements.

25.0 FUELING STATION LICENCE AND USE AGREEMENT – PROVISION OF SERVICE TO THIRD PARTIES

Reference: Exhibit B-1, Appendix A

25.1 Is there a provision in the BFI Agreement that precludes the provision of CNG refuelling service to third parties? If so, please identify the applicable section.

Response:

No, there is no provision to exclude the possibility of extending services to third parties. Extending service to third parties would require the consent of BFI as it is on its premises. At the present time, BFI is not interested in opening up the fueling service to third parties. If this should be pursued at some point in the future a further agreement would have to be reached and that agreement would be subject to further BCUC approval.

25.2 Is there a provision in the BFI Agreement to provide public access to the CNG refueling station? If so, please identify the applicable section.

Response:

No, there is no provision in the BFI Agreement providing for extension of CNF fueling services to third parties. BFI has indicated that it is not interested in providing such services at their site at the present time.

For clarity, under the Agreement (clause 6.7), BFI is responsible for the security of the fueling station to the satisfaction of FEI.

25.3 Does FEI or BFI contemplate that the station could be made available for public use? If so, would BFI offer the service or would FEI?

Response:

Please refer to the response to BCUC IR 1.25.1.

25.4 Please confirm that FEI would seek British Columbia Utilities Commission (Commission) approval prior to offering a CNG refuelling to third parties at the BFI refuelling station.

Response:

Please refer to the response to BCUC IR 1.25.1.

26.0 FUELING STATION LICENCE AND USE AGREEMENT –

FEI EXCLUSIVE RIGHT TO PROVIDE DELIVERY SERVICE TO BFI

Reference: Exhibit B-1, Appendix A; Exhibit A2-6, Tariff Supplement J-1, p. 6; Exhibit A2-7, City of Surrey Corporate Report, p.6

26.1 Please confirm that, in contrast to the Waste Management Agreement, the BFI Agreement does not give FEI the exclusive right and obligation to provide the delivery service for natural gas dispensed at the BFI station. If FEI disagrees, please indicate the section in the BFI Agreement that provides FEI the exclusive right.

Response:

This response also answers BCUC IR 1.26.2.

Since there are no alternatives for BFI to obtain natural gas delivery other than through the FEI's natural gas delivery system, this condition was not incorporated in the BFI Agreement. Thus FEI is the exclusive provider of natural gas delivery service for the customer whether a condition is incorporated in the service agreement or not.

Clause 7 (a) (i) of the WM Agreement was included to express the customer's alternative to either purchase natural gas commodity from FEI or a natural gas marketer under an existing FEI rate schedule. This condition has not changed for BFI; as a customer under Rate Schedule 25 BFI purchases natural gas commodity from a natural gas marketer or provides the gas themselves.

"The development of an Organics Biofuel Processing Facility by the City could provide fuel for CNG-powered vehicles." (Exhibit A2-7, p. 6)

26.2 Are there any alternatives for BFI to obtain natural gas supply other than through the FEI delivery system?

Response:

Please refer to the response to BCUC IR 1.26.1.

26.3 Under the BFI Agreement does BFI have the contractual opportunity to generate biogas from organic waste collected under its contract with the City of Surrey and use this gas to supply the refuelling station?

Response:

Please refer to BCUC IR 1.26.4.

While there is no such condition in the BFI Agreement, BFI has the opportunity to purchase renewable natural gas under FEI's Biomethane program under a separate tariff.

26.4 If an Organics Biofuel Processing Facility is developed by the City of Surrey, what are the potential impacts on the BFI refuelling project, the throughput at the refuelling station and the degree to which the refuelling station costs are recovered from BFI?

Response:

The possibility of an Organics Biofuel Processing Facility has no impact on the BFI refueling agreement or the degree to which refueling station costs are recovered from BFI. Should BFI wish to utilize renewable natural gas from such a facility, this could be achieved through displacement. For example, the City of Surrey could deliver biogas as a supplier into the FEI biomethane program and BFI could purchase biomethane from this program notionally delivered at the Coquitlam site. However, such arrangement would have no impact on the take-or-pay commitments stipulated in the BFI Agreement as gas supply (conventional or renewable) is provided under separate tariffs.

27.0 FUELING STATION LICENCE AND USE AGREEMENT - TERM

Reference: Exhibit B-1, Appendix A, pp. 1, 7

“THIS AGREEMENT is made effective as of January 31, 2012 (the “Effective Date”) (Exhibit B-1, Appendix A, p. 1)

“The term of this Agreement shall commence on the Effective Date and shall expire on September 30, 2019” (Exhibit B-1, Appendix A, p. 7)

27.1 Please confirm that the Effective Date of the BFI Agreement is January 31, 2012.

Response:

Confirmed.

See also the response to BCUC IR 1.29.1, 1.29.1.1.

27.2 Given the subject BFI Agreement commences January 31, 2012, please indicate the date when the initial year that the Minimum Guarantee set out in Section 7.2 of the BFI Agreement commences. If this date is other than January 31, 2012, please identify the date the initial year commences and the section in the BFI Agreement that determines this date.

Response:

The minimum guaranteed volumes as set out in section 7.2 of the BFI Agreement begins when the station has been commissioned and is available for service. For the BFI service, this date is fixed by the City of Surrey contract which requires BFI’s to commence waste collection service on October 1, 2012 at the latest. Thus, there will be 7 full years of minimum guaranteed volume when the initial term of the Agreement expires on September 30, 2019.

28.0 FUELING STATION LICENCE AND USE AGREEMENT – ANNIVERSARY DATES

Reference: Exhibit B-1, Appendix A, Section 7.1

In Section 7.1(a) of the Agreement, the Capital Rate is "increased annually by 2% on the anniversary of the Effective Date each year of the Term".

In Section 7.1(b), the O&M Rate is "adjusted each year of the Term by the percentage increase, if any, in the Consumer Price Index (published by Statistics Canada for the City of Vancouver, all items, not seasonally adjusted) from the previous 12 month period."

28.1 What is the anniversary that the O&M Rate is adjusted on? Is it the anniversary of the Effective Date (i.e. January 31) or is it a different date? If it is a different date, please indicate the date and how it is referenced in the BFI Agreement.

Response:

Please refer to the response to BCUC IR 1.27.2 which also answers this question.

Both Capital and O&M rates are adjusted each year on October 1st, the first day of the in-service term. October 1, 2012 is the In-Service date of the Agreement and the date the fueling station will be available for service. Although the Effective Date of the agreement is January 31, 2012, the initial term of the agreement is October 1, 2012 to September 30, 2012.

29.0 FUELING STATION LICENCE AND USE AGREEMENT – DEFINITION OF YEAR

Reference: Exhibit B-1, Appendix A, Section 7.2 and Section 8.2

"7.2 **Minimum Guarantee**. The Customer acknowledges and agrees the Base Rate has been calculated by FEI having regard to, among other things, the Customer's estimated CNG demand profile and the number of vehicles served by the Fuelling Station, and accordingly, the Customer agrees to pay a minimum annual Service Charge (the "**Minimum Guarantee**") based on a minimum quantity of 60,000 GJ of CNG being dispensed from the Fuelling Station per year (the "**Minimum Quantity**") calculated by multiplying the applicable Base Rate for such year by the Minimum Quantity."

"8.2 Within 15 days of the end of the year, either separately or as part of the last monthly statement for each year, FEI shall identify the aggregate CNG consumption for such year."

29.1 Please provide the definition of "year" as referred to in Sections 7.2 and 8.2 of the BFI Agreement and indicate the section in the BFI Agreement that defines "year".

Response:

Both Sections 7.2 and 8.2 of the BFI Agreement relate to the quantity of CNG dispensed. As indicated in the response to BCUC IR 1.27.2, since the fueling service commences on October 1, 2012, each year begins on October 1. "Year" is not a defined term under the BFI Agreement.

29.1.1 Is "year", as referred to in the Agreement for the purpose of determining whether BFI has reached the Minimum Quantity each year, defined as a calendar year, a 12 month period commencing on Effective Date of the BFI Agreement , a 12 month period commencing on the in-service date of the station?

Response:

Please refer to the response to BCUC IR 1.27.2.

30.0 FUELING STATION LICENCE AND USE AGREEMENT – DEFINITION OF YEAR

Reference: Exhibit B-1, Appendix A, Schedule B

30.1 Are the "Approximate Contract Termination" dates set out in Schedule B of the BFI Agreement meant to be January 1 of the indicated year, September 30, end December 31, or some other point in the year? If some other point in the year, please indicate the date.

Response:

The approximate contract termination date is set out to be September 30th. In-service of the fueling station commences on October 1, 2012 and runs through September 30, 2013 for the full 365 days in the first contract year. The Contract Termination date is September 30, 2019.

30.1.1 If the BFI Agreement was to terminate at a point in the year other than the date to which the calculation is referenced, how would FEI determine the outstanding capital cost? Would it be prorated?

Response:

Yes, the outstanding capital cost would be prorated if the BFI Agreement were to terminate at a point in the year other than the termination date.

The depreciation expense and the net salvage provision would be prorated to arrive at the net book value of the assets at the time of the termination. The calculation would also include the cumulative excess fueling station recoveries to-date.

31.0 FUELING STATION LICENCE AND USE AGREEMENT – MINIMUM QUANTITY

Reference: Exhibit B-1, Appendix A, p.7

"7.2 **Minimum Guarantee**. The Customer acknowledges and agrees the Base Rate has been calculated by FEI having regard to, among other things, the Customer's estimated CNG demand profile and the number of vehicles served by the Fuelling Station, and accordingly, the Customer agrees to pay a minimum annual Service Charge (the "**Minimum Guarantee**") based on a minimum quantity of 60,000 GJ of CNG being dispensed from the Fuelling Station per year (the "**Minimum Quantity**") calculated by multiplying the applicable Base Rate for such year by the Minimum Quantity."

31.1 Is the Base Rate and the Minimum Quantity of 60,000 GJ per year calculated on the basis that 52 vehicles will be served or on the basis that 86 vehicles will be served?

Response:

Please see our response to BCUC IR 1.5.1.

The Base Rate and Minimum Quantity of 60,000 GJ per year are based on serving 52 vehicles. The rate structure of the BFI Agreement is based on the actual capital cost for 86 vehicles and on a minimum contract demand for 52 vehicles. This rate structure allows FEI to fully recover the present value of the cost of service associated with provision of CNG fueling service to BFI over the term of the Agreement. It is the Minimum Quantity, not the number of vehicles, which impacts the rate structure.

32.0 ALLOCATION OF OVERHEAD AND MARKETING COSTS

Reference: Exhibit B-1, p.19, Exhibit A2-6, Section 7(b) (iv), p.6

"Spread over FEI's expected CNG/LNG sales volume estimate of 163,489 GJ in 2012[25] …"

"FEI's expected volume used to calculate the overhead component of the fueling charge does not include incremental NGT customers or fuel consumption beyond existing customers' minimum volume commitments."

"[25]Forecast for 2012 includes WM (30,000 GJ), KSD (5,000 GJ), BFI (15,000 GJ), Vedder Temporary (49,320 GJ) and Vedder Permanent (64,169 GJ)."

"The Base Price of $5.37 per GJ assumes a volume of 19,000 per year." (Exhibit A2-6, Section 7(b)(iv))

32.1 Please confirm that the minimum volume commitment for Waste Management is 1,583 GJ per month.

Response:

This response also answers BCUC IRs 1.32.2 and 1.32.3.

FEI would like to clarify the statement on page 19 of Exhibit B-1. It reads as follows:

> *"FEI's expected volume used to calculate the overhead component of the fueling charge does not include incremental NGT customer or fuel consumption beyond existing customers' minimum volume commitments."*

This wording "*or fuel consumption beyond existing customers' minimum volume commitments*" was inadvertently included in the statement, and should be removed. FEI apologizes for this error. The removal of this sentence does not change any of the overhead calculation.

FEI confirms the minimum volume commitment for Waste Management is 1,583 GJ per month or 19,000 GJ per year as set out in the Waste Management Agreement. The volume estimate of 30,000 GJ is beyond the customer's existing minimum volume commitment.

For the purposes of allocating overhead and marketing costs, FEI is forecasting Waste Management volumes for 2012 to be 157% of the minimum contract demand of 19,000 GJ (157% of 19,000GJ = 30,000GJ). Waste Management's actual consumption for the 12 month period from March 2011 to February 2012 was 29,846 GJs. Therefore, FEI believes it is reasonable to assume this consumption rate will continue throughout 2012.

The WM Agreement was approved by Commission Order No. G-128-11 on July 19, 2011. In Order No. G-128-11, the Commission also established the Overhead and Marketing Charge requirement for Section 12B of the GT&Cs, and the approved Section 12B was revised to comply with the requirement. Since the WM Agreement was approved prior to this requirement, the WM Base Price did not incorporate an allocation for Overhead and Marketing and did not consider volumes in excess of minimum contract quantity to the extent of 157%.

32.2 Please confirm that, for the purposes of allocating overhead and marketing costs in this Application, FEI is forecasting Waste Management volumes for 2012 to be 157% of the minimum contract quantity set out in the WM Agreement.

Response:

Please refer to the response BCUC IR 1.32.1.

32.3 Did the allocation of O&M used to determine the WM Base Price contemplate that the volumes would be in excess of the minimum contract quantity to this extent?

Response:

Please see response to BCUC IR 1.32.1.

32.4 Is it reasonable to assume that the BFI volumes used for the purpose of allocating overhead and marketing costs will be limited to the minimum contract quantity given the current FEI forecast for Waste Management?

Response:

For the purpose of allocating overhead and marketing costs, FEI believes it is reasonable to assume BFI volumes are limited to the minimum contract volume.

As discussed in response to BCUC IR 1.32.1, Waste Management has proven its CNG trucks consume volumes nearly 157% greater than its minimum contract volume based on the past 12 months of operation. FEI has no indication at this time that BFI will perform or operate its CNG trucks in a similar manner. Therefore, FEI's best estimate is based on BFI's minimum contract volume.

32.5 Recalculate the Overhead and Marketing Charge in Table 7 of the Application assuming BFI volumes are 150% of the minimum contact quantity.

Response:

Assuming BFI volumes are 150% of the minimum contract quantity for 2012 (150% x 15,000 GJ = 22,500GJ), the overhead and marketing charge is as follows:

Department or Activity (a)	FTE (b)	2012 Cost Estimate ($) (c)	Allocated Cost Estimate ($) (d)	CNG/LNG Sales Volume Estimate (GJ) (e)	Overhead & Marketing Charge ($/GJ) (f)
NGT Sales Manager	0.25	131,762	32,941 (d)=(b)x(c)	170,989	0.19 (f)=(d)/(e)

Where column (e) =

CNG/LNG Project	GJ
BFI	22,500
KSD	5,000
WM	30,000
Vedder Temporary	49,320
Vedder Permanent	64,169
Total	**170,989**

Under this assumption the net impact to the overhead and marketing charge is a decrease of $0.01 per GJ.

32.6 Recalculate the Overhead and Marketing Charge in Table 7 assuming volumes equal to the minimum volume commitments each of the CNG /LNG projects.

Response:

Assuming volumes are equal to the 2012 minimum volume commitments for each CNG/LNG project, the following is the overhead & marketing charge:

Department or Activity (a)	FTE (b)	2012 Cost (c)	Allocated Cost (d)	2012 CNG/LNG Sales (e)	Overhead & Marketing (f)
NGT Sales Manager	0.25	131,762	32,941 (d)=(b)x(c)	152,489	0.22 (f)=(d)/(e)

The following are the 2012 minimum volume commitments for each project (column e), please note that the BFI minimum volume reflects the three months of operation in 2012 (5,000 GJ per month x 3):

CNG/LNG Project	GJ
BFI	15,000
KSD	5,000
WM	19,000
Vedder Temporary	49,320
Vedder Permanent	64,169
Total	**152,489**

Under this assumption the net impact to the overhead and marketing charge is an increase of $0.02 per GJ.

33.0 IMPACT ON FEI'S RATEPAYERS

Reference: Exhibit B-1, Section 3.3.4, pp. 9-10

FEI states that: "the Commission cautioned that 'FEI's ratepayers must be insulated, to the greatest extent possible, from the costs and risks of the program.'"

33.1 Does FEI believe that it has "to the greatest extent possible" insulated FEI's natural gas ratepayers for the costs and risks of the CNG and LNG Service program and this Application?

Response:

FEI believes the rate structure in the BFI Agreement conforms to the Commission-endorsed Section 12B of the GT&Cs, which includes the following conditions to insulate FEI's natural gas ratepayers:

- Actual capital investment in the fueling station;
- Customer will be charged a take or pay fueling charge (of $4.66 per GJ, minimum contract demand of 60,000 GJ);
- All operating and maintenance expenses, with no adjustment for capitalized overhead, necessary to serve the Customer, escalated annually by British Columbia CPI;
- An allowance for overhead and marketing costs of $0.20 per GJ relating to developing NGV Fueling Station Agreements to be recovered from the Customer; and
- Agreement to pay FEI the un-depreciated capital cost of the fueling station if the contract is terminated after the initial term of seven years.

Any further service agreement that FEI will negotiate with potential CNG/LNG customers not only must adhere to these 12B of the GT&Cs, but also must be practical in its rate structure and commercial terms.

33.1.1 In what ways, and for what risks associated with this Application, are there still risks to the FEI natural gas ratepayer that have not been insulated?

Response:

FEI believes that FEI's fueling service offered under the current GT&C's achieves the Commission's intent in the NGT Decision that to the extent possible the cost of the fueling service is recovered from the customer and that the natural gas ratepayers bear minimum risks in the service offering. While bearing minimum risks, the natural gas ratepayers benefit from the delivery margin brought by the CNG fueling services. Without the fueling service, this benefit cannot be realized. That is, if this or future CNG/LNG CPCNs are not approved, FEI may lose out on the opportunity to earn revenue benefits and achieve further reductions to existing delivery rates. FEI natural gas ratepayers have the potential to benefit from additional delivery margin revenues generated under FEI's Rate Schedules from NGT customers.

The minimum risks that FEI natural gas ratepayers may assume is the cost forecast to operate and maintain CNG or LNG fueling stations. This is discussed further in the response to BCUC IR 1.33.2.

As discussed in the Application at page 13, FEI acknowledges timing of construction risk and operational risks associated with the Project. FEI believes that these risk factors have been addressed by the mitigating factors identified.

Similar to other natural gas customers, there is a risk of customer bankruptcy or default associated with investing capital (i.e. service lines, main extensions) in a commercial or industrial customer. FEI performed an internal credit assessment and deemed BFI to be approved for service with no security requirements. This credit assessment is common practice with other traditional natural gas customers. Furthermore, BFI is already a commercial customer under Rate Schedule 2.

33.2 Will the FEI natural gas ratepayer assume any of the risk that a CNG or LNG fueling facility may cost more than forecast to construct or to operate and maintain? If yes, please explain in detail how this could occur.

Response:

FEI has divided this response into two parts: the forecast risk to construct and the forecast risk to operate and maintain.

First, FEI natural gas ratepayers assume the risk associated with the forecast to construct however FEI believes it to be minimal due to various mitigating factors.

Like any capital project, there will be variances between the forecast and the actual. In the BFI Agreement, this variance risk is addressed by having a provision to allow the parties to amend the service charge if the variance is greater or less than 2 percent. This provision has also been used in Vedder's Permanent Refueling Agreement (in a forthcoming CPCN Application submission) and may be adopted in future CNG/LNG fueling service agreements. This, in FEI's view, will allow FEI to recover the actual capital cost of the project. Using a variance range of plus or minus 2 percent for amendments to the fueling service charge is appropriate because it avoids costs from contract amendments and equates to a minimal portion of the total capital costs. Any variances (positive or negative) within this 2 percent range will be offset by delivery margin revenue benefits generated by the Rate Schedule for each NGT customer. These potential benefits, when compared over the term of each NGT service agreement, are substantially greater than a one-time potential forecast cost variance of up to 2 percent.

Therefore, FEI does not believe the 2 percent variance represents a significant risk to ratepayers. Please see BCUC IRs 1.33.4 and 1.33.5 for additional discussion on the 2 percent variance.

Second, FEI natural gas ratepayers assume the risk associated with the cost forecast to operate and maintain CNG or LNG fueling stations. NGT customers seek cost certainty with respect to their fueling costs. This is why FEI has included an inclining rate structure to its capital portion of the fueling charge. It is not practical or salable for FEI and the customer to review the actual O&M cost at the conclusion of each contract year, amend based on actual costs, and then renegotiate the service agreement. Any cost variances associated with O&M cost estimates for NGT customers will also be offset by delivery margin revenue benefits generated from each NGT service agreement.

33.3 Please discuss how the risks to FEI (as opposed to FEI's natural gas ratepayers) have been mitigated in this Application and future CNG and LNG Service applications.

Response:

FEI believes there is minimal risk to FEI (as opposed to FEI's natural gas ratepayers) as a result of this Application. FEI shareholders bear some risks because FEI did not forecast the costs or recoveries related to the BFI fueling station in the FEU's 2012-2013 RRA. As a result, any revenue surplus or deficiency pertaining to the BFI fueling station (excluding recoveries in excess of minimum contract demand) falls to the shareholder for the two year period. This potential two year revenue variance is expected to be minimal as demonstrated in the response to BCUC IR 1.36.1.

In terms of further CNG/LNG Services, FEI will comply with the approved Section 12B of the General Terms and Conditions, which will result in minimal risks to FEI and its ratepayers.

FEI states that one way FEI has minimized the risks to FEI's natural gas ratepayers is: "There is a requirement to amend the fueling charge if the actual capital cost for the Project results in a variance of greater or less than 2 percent;"

33.4 Does an allowance to change the fuelling charge only if actual capital costs for the project are greater than 2 per cent, rather than use actual capital costs with no allowance for variance, not <u>increase</u> the risk to FEI's natural gas ratepayers and reduce FEI's risk?

<u>Response:</u>

FEI does not agree that including this condition increases the risk to FEI's natural gas ratepayers.

FEI included the 2 percent variance condition in the BFI Agreement as a materiality test to avoid subsequent amendments to the agreement if capital costs variances were minimal. If the BFI project is completed outside the 2 percent range, then FEI will amend the agreement to reflect the actual capital costs of the project, which poses minimal risk to FEI natural gas ratepayers. . FEI acknowledges there is a minimal risk if the project is completed above the forecast cost, at less than a 2 percent variance. However the incremental delivery margin benefits generated over the term of the service agreement more than offsets a one-time, potential 2 percent cost variance to FEI's natural gas ratepayers. (An illustration of this calculation for the BFI Agreement is shown in the response to BCUC IR 1.23.1). FEI natural gas ratepayers will also benefit if the project is completed below the forecast cost, at less than a 2 percent variance.

Whether the variance is positive or negative, the overall impact of cost variances on delivery rates for natural gas customers is minimal, and the impact of the project overall on delivery rates for natural gas customers is favourable.

33.5 Please confirm that the financial "at risk" portion to FEI is $37,000.

Response:

Confirmed. However, FEI does not believe a one-time, potential maximum cost of $37,000 poses a significant risk to FEI ratepayers due to the delivery margin revenue benefit of approximately $483,000 over the contract term, which is expected to be generated.

See also the response to BCUC IR 1.23.1.

34.0 FUELING STATION LICENSE AND USE AGREEMENT

Reference: Exhibit B-1, Appendix A

34.1 Please confirm that FEI has assessed the current and future credit-worthiness of BFI and found it to be satisfactory.

Response:

FEI confirms it has assessed the current and future credit-worthiness of BFI and has approved the customer with no security requirements (i.e. irrevocable letter of credit, cash deposit).

35.0 UNRECOVERED CAPITAL

Reference: Exhibit B-1, Appendix A, Clause 11.1; Exhibit B-1, Appendix B, Section 12B.5; Exhibit B-1, Section 3.3.4, p. 9

Order G-128-11 states "Accordingly, the Commission Panel has determined that to be approved, the General Terms and Conditions must include a provision requiring the customer to pay any unrecovered capital in those cases where the initial contract is not renewed, or a similar provision that provides equivalent protection."

35.1 Does FEI believe that the contract with BFI fulfills this provision?

Response:

Yes, FEI believes that Clause 11.1 of the BFI Agreement fulfills this provision. Please see our response to BCUC IR 1.27.2 for clarification regarding the commencement date for fueling service.

From Exhibit B-1, Appendix A:

11.1 Expiry of Term. The Customer acknowledges the Base Rate and Minimum Quantity have been calculated by FEI by applying, among other things, a 20 year term despite the Term of this Agreement (without renewal) being seven (7) years. As a result, the Customer acknowledges and agrees that in the event this Agreement is terminated without cause at any time prior to the 20th anniversary of the Effective Date, the Customer will pay FEI, within 30 days of invoice, the following amounts depending on the length of Term:

(a) For expiry prior to or at the end of the Initial Term, the sum of:

(i) the unrecovered un-depreciated capital cost of the Fueling Station, as calculated in accordance with section 11.8; and

(ii) an amount equal to earnings forgone by FEI as calculated in accordance with section 11.7.

(b) For expiry after the Initial Term but prior to the 20th anniversary of the Effective Date, the sum of:

(i) the unrecovered un-depreciated capital cost of the Fueling Station as calculated in accordance with section 11.8;

plus, FEI's costs for removing the Fueling Station (including equipment removal and restoration of the Lands) in accordance with section 11.5, if the Customer requires removal.

35.2 Under what conditions would BFI not be required to pay the unrecovered capital?

Response:

FEI does not foresee any condition where BFI would not be required to pay the unrecovered capital. As stated in response to BCUC IR 1.35.1, Clause 11.1 satisfies the Commission's requirement stated in Order G-128-11.

In addition, the following provisions ensure that BFI pays the unrecovered capital:

- Termination by the Customer for Cause (Clause 11.3);
- Termination by FEI for Cause (Clause 11.4); and,
- Transfer of the Fueling Station (Clause 11.6).

36.0 DEFERRAL ACCOUNTS

Reference: Exhibit A2-3, p. 3

"a) Reductions to the capital, O&M and other revenue forecasts to reflect fueling station facilities additions of zero in both 2012 and 2013."

36.1 Will FEI need to establish deferral accounts to capture the cost of applications, O&M costs, the cost of service and incremental CNG recoveries related to fueling station facilities additions not forecasted in the FortisBC Energy Utilities Revenue Requirements Application (2012-2013 FEU RRA)? Please explain why, or why not. If deferral accounts are required, please provide the type of account and amortization period for each account.

Response:

No, FEI will not require the establishment of deferral accounts to capture the cost of applications, O&M costs, the cost of service and incremental CNG recoveries relating to fueling station facilities additions not forecast in the 2012-2013 FEU RRA.

Please refer to the response to BCUC IR 1.46.1 and 1.46.2 for a discussion on application costs. A new deferral for application costs is not required; however, FEI will add application costs not attributable to BFI to the existing NGV for Transportation Application deferral account.

The O&M and other cost of service items are captured in the fueling station rate(s). The fueling station rate(s) are based on a take or pay contract where the recoveries will offset the costs throughout the term of the agreement. Thus, generally speaking, FEI does not expect a material variance between the costs and recoveries to occur during 2012 and 2013 and as a result does not require a deferral account.

For example, the expected net variance between BFI fueling station costs and revenue in 2012 and 2013 is very minimal and is forecast at $3 thousand, as shown in the table below.

	2012	2013	Reference
Cost of Service	$307,000	$261,000	Schedule 1, Line 21
Less : Fueling Station Revenues	$280,000	$285,000	Schedule 12, Line 2
Annual Revenue Deficiency (Surplus)	$27,000	($24,000)	

A variance exists because the capital charge (one of the components of the fueling station rate) has an escalating rate structure which results in annual revenue deficiencies in the early years of the contract and annual revenue surpluses in the later years of the contract. For the two year period, the variance between the fueling station cost of service and recoveries (excluding recoveries associated with volume in excess of minimum contract demand) will be the responsibility of the shareholder because the BFI agreement was not included in the FEU's 2012 and 2013 RRA. However, as a part of future Revenue Requirement Applications, these annual timing differences will be captured in the forecast costs and recoveries and reflected in the delivery rates of non-bypass customers. In the case of BFI, these annual timing differences are expected to result in annual revenue surpluses as shown on Schedule 11, Line 15 for the years 2014-2018.

To clarify, FEI will continue the use of the Commission approved CNG and LNG Recoveries deferral account. Throughout the term of the BFI contract, any excess fueling station recoveries received from volumes in excess of the minimum contract demand will be captured in the CNG & LNG Recoveries deferral account to the benefit of natural gas ratepayers, and amortized over one year period through the delivery rates of non-bypass customers.

37.0 CAPITAL COST – PROJECT MANAGEMENT

Reference: Exhibit B-1, Section 5.1, p. 15

"**Table 4: BFI CNG Fueling Station Capital Expenditures**
FortisBC Engineering, Project Management, Commissioning $ 199,875"

37.1 Please explain how FEI will account for the FortisBC Engineering, Project Management, Commissioning revenues of $199,875 included in the BFI CNG Fueling Station Capital Expenditures?

Response:

FEI accounts for these activities as it would for any other business activities for a capital project. The costs for FortisBC Engineering, Project Management, and Commissioning are tracked to a capital order, which recovers these costs, amongst others, from BFI.

37.2 Given that these revenues and costs associated with the FortisBC Engineering, Project Management, and Commissioning of the BFI CNG Fueling Station were not forecasted in the 2012-2013 FEU RRA, should a deferral account be established to capture these costs revenues? Please explain why, or why not. If deferral accounts are required, please provide the type of account and amortization period for each account.

Response:

Please refer to the response to BCUC IR 1.36.1 where FEI explains why no deferral account is required.

38.0 SYSTEM EXPANSION REQUIREMENTS

Reference: Exhibit A2-6, Tariff Supplement J-1, p. 1

As per Tariff Supplement J-1 of the FEI tariff, the Waste Management of Canada Ltd. (WM) refueling station, which commenced service in 2011 and has a minimum take-or-pay commitment of 1583 GJ per month, is located at 2330 United Boulevard in Coquitlam.

38.1 Please confirm that the WM refueling station and the BFI refuelling station are in close proximity on the FEI distribution system.

Response:

Confirmed. The two stations are within one kilometre of each other on FEI's distribution system.

38.2 Please confirm that the combined incremental annual load for the two refuelling stations is 78,996 GJ per year, at the minimum contractual take-or-pay quantities, for these two CNG Service customers.

Response:

Confirmed.

38.3 Was any system expansion required to accommodate the WM refueling station load? If so, please describe the nature of the system expansion and the cost.

Response:

No system expansion was required for the WM fueling station. FEI provided a service line connection and meter set as would be the case for any new customer.

38.4 Will the additional load from the BFI CNG refueling station result in a new service line, a service line upgrade, a main extension or a main extension upgrade? For each item explain why, or why not. If upgrades are required, please provide the economic tests.

Response:

This response relates to BCUC IRs 1.38.4 and 1.38.5.

FEI estimates that BFI's 60,000 GJ per year load can be accommodated without system upgrades (including system improvements and reinforcements). All that is required for providing service to BFI is a service line and meter set. The reason that no main extension or main extension upgrade is required is that the existing system has sufficient capacity to service the 60,000 GJ/year load.

38.5 Will the additional load from the BFI CNG refueling station result in a system improvement or reinforcement? Please explain why, or why not. If a system improvement or reinforcement is required, please provide the economic test.

Response:

Please refer to BCUC IR 1.38.4.

39.0 RATE - CHARGE FOR VOLUMES IN EXCESS OF BASE AMOUNT

Reference: Exhibit B-1, Section 5.2, p. 16; Appendix A, p. 7

"Revenues in excess of the minimum take-or-pay demand are calculated using a rate set at 50% of BFI's total fueling service rate of $4.66/GJ, or $2.33/GJ (Clause 7.1 (c)).15" (Exhibit B-1, p. 16)

"7(c) if more than 5,000 GJ of CNG (the "Base Amount") is dispensed from the Fueling Station in any month, the rate payable for such CNG in excess of the Base Amount shall be the O&M Rate plus fifty percent (50%) of the Capital Rate." (Exhibit B-1, Appendix A, p. 7)

39.1 There appears to be an inconsistency in the calculation of the rate to be charged for volumes in excess of the Base Amount. Is the correct rate $2.33/GJ or $2.848/GJ ($1.033/GJ plus 50 percent of $3.629)?

Response:

The rate of $2.33/GJ was incorrectly calculated and shown in the Application on page 16. The correct rate for volumes in excess of the Base Amount is $2.848/GJ ($1.033/GJ O&M rate plus $1.815/GJ (50 percent of $3.629/GJ)), as described in the Fueling Station License and Use Agreement.

40.0 VARIATIONS IN THE TERMS OF SERVICE

Reference: Exhibit A2-10, p. 23; Exhibit B-1, Appendix A; Exhibit A2-6

"Section 59(2)(b) of the UCA states: *A public utility must not extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description*. However, FEI argues that it needs considerable flexibility to negotiate terms of individual agreements that could extend beyond the proposed General Terms and Conditions. The Panel is concerned that this potential for significant variations in the terms of each custom service agreement could constitute a discriminatory extension of a privilege to a customer." Underlined for emphasis (Exhibit A2-10, Order G-128-11, p. 23)

40.1 Is the proposed CNG service to BFI "substantially similar" to the CNG service to WM? Please explain why, or why not.

Response:

The proposed CNG service is similar to the service provided for Waste Management in that both agreements provide for construction and maintenance of a fueling station on a host customer's site. Both involve compression and delivery of fuel to a fleet of trucks through time fill fueling posts and are designed to deliver 3,600 PSI fuel to the vehicle.

While the fueling services provided are similar, there are substantial differences in the scope and scale of the operation and in the resulting cost of service. For example, the WM Agreement rate was based on providing fuel for 20 trucks, while the BFI Agreement is based on 52 trucks. WM required two compressors while BFI requires three. The WM trucks operate six days a week while the BFI trucks are expected to operate five days per week.

The BFI Agreement is developed in accordance with GT&C 12B, which was revised based on the NGT Decision and the WM Agreement. But both service agreements (BFI and WM) are similar in that the rates developed in the agreements are based on a take-or-pay commitment from the customer and on the cost of service model. The agreements provide for different rates because the inputs into the model are different. The most important variables are the committed volumes, the capital investment, and the estimated operating and maintenance costs. The BFI Agreement complies with all the provisions from the GT&C 12B.

The process of negotiating a fair agreement with each party resulted in agreements that are tailored to each party's needs. In each case the terms and conditions reflect the level of cost incurred in providing the service and the level of customer commitment in terms of take-or-pay guaranteed volumes. In each case the conformance with Commission-endorsed GT&C's will ensure that rates are set without discrimination.

40.2 Please complete the table below comparing the BFI Agreement to the WM Agreement (Exhibit A2-6, TGI Tariff Supplement No. J-1).

Comparison of BFI and WM Agreements

BFI Agreement Reference	**BFI Agreement**	**WM Agreement Reference**	**How BFI Agreement Compares to WM Agreement**
1.2 Term			
1.2 Renewal			
5.6 Corporate Branding			
6.2 Vandalism			
6.5 Training			
7.1 Fuelling Charges (a) Capital Rate (b) O&M Rate (c) Rate for In excess of Base Amount			
7.2 Minimum Guarantee			
7.3 Projected Capital Expenditure			
11.7 Calculation of Earnings			
11.8 Calculation of Cost of Fuelling Station			
12.1 Insurance			
		7(a) Supply of Natural Gas	

<u>Response:</u>

Comparison of BFI and WM agreements.

BFI Agreement Reference	BFI Agreement	WM Agreement Reference	How BFI Agreement Compares to WM Agreement
1.2 Term	7 Years	Section 1 - Term of Agreement	WM term is 10 years, BFI is 7 years. Despite the different term there is no risk of stranded assets to rate payers because each agreement requires a capital buyout if the station is not used for 20 years. The 7 year term for BFI is derived from the customer's contractual term with the City of Surrey, whereas WM has no similar commitment.
1.2 Renewal	3 years	Section 1 -Term of Agreement and 9.c Termination at the Completion of the Initial Term	Both agreements provide for subsequent extensions. Both agreements require the customer to pay out remaining capital if agreements are not extended. Term of agreements and extensions are different as each customer has different business circumstances. Both agreements protect rate payers from stranded asset risk.
5.6 Corporate Branding	Fortis has rights to put signage on vehicles indicating vehicles powered by natural gas	None	Similar clause to BFI Agreement was included in the Contribution Agreement for incentive funding in the WM case. Net effect is same. Vehicles will have branding indicating they are powered by natural gas.
6.2 Vandalism	BFI responsible for costs associated with vandalism of equipment	Section 4 (b) (iv) – Maintenance of the Fueling Station and 4 (f) - Security	Under 4 (f) WM is responsible for security of the site. Under 4 (b)(iv), WM is responsible for "any and all damage to the Fueling Station arising directly or indirectly from the acts or omissions of WM or its agents or other persons for whom at law WM is responsible." FEI's position is that most acts of vandalism would fall into the case where WM would be responsible for costs.

BFI Agreement Reference	BFI Agreement	WM Agreement Reference	How BFI Agreement Compares to WM Agreement
6.5 Training	FortisBC provides initial training, then customer assumes ongoing responsibility, with refresher training provided by Fortis	Section 4 (g) (ii) - Safety	Fortis provides safety training to WM with respect to fueling vehicles at the Fueling Station and shall provide such additional training as reasonably required by WM. No significant difference.
7.1 Fueling Charges **(a) Capital** **(b) O&M Rate** **(c) Excess Throughput Rate**	 $3.629/GJ $1.033/GJ $2.848/GJ	Section 7 – Supply of Natural Gas and Fueling Charges	(a) $5.31/GJ (Capital and O&M) (b) N/A (Included in Base) (c) $1.33/GJ The base rate for the WM Agreement included the O&M charge. For the BFI Agreement the O&M was split out separately in order to comply with the GT&C's approved in Commission Order No. G-14-12. The rates under each agreement are different, but they have each been determined using the Cost of Service methodology. The rate variations reflect the different minimum contract volumes, the different capital costs and the different operating costs for each installation.
7.2 Minimum Guarantee	60,000 GJ	Section 7 (c) – Supply of Natural Gas	Minimum quantity of CNG is 1,583 GJ per month, or 19,000 GJ per year. BFI will have 52 trucks while WM has only 20.

BFI Agreement Reference	BFI Agreement	WM Agreement Reference	How BFI Agreement Compares to WM Agreement
7.3 Projected Capital Expenditure	$1.861 million	Capital cost not specified in the agreement, but was embedded in the rates established.	The BFI agreement has the capital specified in order to conform with the requirements of Commission Order No. G-14-12, Section 12B of the GT&C's.
11.7 Calculation of Earnings	This provision allows FEI to recover its lost earnings in the event of an occurrence such as early termination of the agreement. It also relates to Section 11.4 Termination by FEI for Cause.	Section 9 (b) (ii) – Termination by Terasen for Cause	Similar treatment where FEI is allowed to recover lost earnings in the event of termination by FEI for cause.
11.8 Calculation of Cost of Fueling Station	A schedule is set out defining the undepreciated capital buyout amounts at various periods.	No reference	In In the WM agreement the amounts have not been calculated in advance. However, in terms of calculating undepreciated capital at termination, there is no net difference in how the two agreements would work. However if the buyout clause is triggered in the BFI Agreement, any revenues in excess of the take or pay minimum will offset the undepreciated capital cost of the fueling station.

BFI Agreement Reference	BFI Agreement	WM Agreement Reference	How BFI Agreement Compares to WM Agreement
12.1 Insurance	Reciprocal Requirement for $5 million in CGL and $5 million in Automobile insurance.	Section 16 - Insurance Requirements of Terasen and Section 17 – Insurance Requirements of WM	WM agreement stipulates CGL of $2 million and pollution liability of $5 million for FEI. WM required to have CGL of $5 million and Automobile Coverage of $5 million. FEI's assessment is that the net insurance requirements under each agreement are reasonable and do not present substantially different risk profiles. The pollution liability insurance coverage presents no significant risk as there is no potential for fuel spills from a CNG station. This was a corporate requirement for WM with respect to fueling stations that generally deal with diesel fuel.
None	None	Section 7 (a) - Supply of Natural Gas	The WM agreement describes gas supply options available to the customer. For the BFI agreement it was decided this was not necessary as gas supply is dealt with under its own tariff and has no impact on the fueling station agreement.

40.3 Do the differences between the proposed BFI Agreement and the WM Agreement constitute a discriminatory extension of a privilege to a customer? Please explain why, or why not.

Response:

No. The reasons are as follows.

First, the comparison between the two agreements is not helpful. The Waste Management Agreement was developed based on a previously proposed General Terms and Conditions. Although the Commission rejected the previously proposed general terms and conditions, it approved the WM Agreement, reflecting the fact that the WM Agreement was the first of its kind (at least in recent years), and as the Commission noted it was a "unique" agreement and it was approved "on an exception basis only". The BFI Agreement was based on the GT&Cs that have revised to the satisfaction of the Commission. There is nothing inappropriate about the FEI now applying for approval of a contract (and future contracts) based on the Commission approved revised GT&Cs that came out of that original NGT Decision. This approach simply reflects FEI's adherence to the Commission's directions in the NGT Decision.

Second, in the NGT Decision, when rejecting the previously proposed GT&Cs, the Commission reasoned that it favored a "more structured approach to the General Terms and Conditions, which will result in a more standard form, leaving less to negotiate and consequently reducing the likelihood that an agreement will be discriminatory within the meaning of section." Based on the commission's directives, section 12B was revised and subsequently approved. All of FEI's contracts going forward, including the BFI Agreement, will be required to adhere to these revised GT&Cs, which as the Commission noted in the NGT Decision should address the requirement found in section 59(2)(b) of the UCA.

Third, as recognized under section 59, there is no undue discrimination if the public utility offering a service made it available to all similarly situated persons. Both Waste Management and BFI received the CNG service offered by FEI. The service received by Waste Management and BFI are substantially similar in that rates established in both service agreements are based on a cost of service model. Under both agreements, the rates to be charged, along with other key terms, allow FEI to recover the present value of the cost of service associated with provision of the CNG service to Waste Management and BFI respectively during the contractual term.

Fourth, the extent of differences in these service agreements do not constitute undue discrimination as they reflect the different circumstances in the operational reality of two different customers, such as the customer's fuel demand requirements, customer operational practices, the physical geography of the property, and other commercial requirements for the operation. Specifically, the rate variations reflect the different minimum contract volumes, the different capital costs and the different operating costs for each installation. Section 59(1) of the UCA states that "A public utility must not make, demand or receive (a) an unjust, unreasonable, *unduly discriminatory or unduly preferential* rate for a service provided by it in British Columbia." [Emphasis added.] Reading section 59(2) together with 59(1) of UCA makes clear what the UCA prohibits is "undue" discrimination. Some rate discrimination, such as a large volume, high load factor industrial customer receiving lower rates than a low volume, low load factor residential customer, or the commercial class paying more than its allocated costs while the residential class is paying less than allocated costs have been accepted. The rate variances in the two agreements here are similarly not undue discrimination.

41.0 VARIATIONS IN THE TERMS OF SERVICE – FEI GT&C, SECTION 12B.4

Reference: Exhibit A2-5, Section 12B.4

41.1 If the differences between the proposed BFI Agreement and the WM Agreement constitute a discriminatory extension of a privilege to a customer, should FEI GT&C, Section 12B.4 be declared interim pending the establishment of standard terms and conditions for customers receiving CNG service? Please explain why, or why not.

Response:

Please refer to the response to BCUC IR 1.40.3. The differences between the proposed BFI agreement and the WM agreement do not constitute a discriminatory extension of a privilege to a customer; hence the GT&C's should not be declared interim.

42.0 VARIATIONS IN THE TERMS OF SERVICE – VOLUMES IN EXCESS OF BASE AMOUNT

Reference: Exhibit B-1, Section 5.2, p. 16; Exhibit A2-10, Order G-128-11

"Through the course of contractual negotiations with BFI, FEI agreed to contribute any contract revenues in excess of the minimum take-or-pay toward the payment required by BFI for the undepreciated capital cost in the event that the buyout is triggered (Clause 11.8 and Schedule B). Revenues in excess of the minimum take-or-pay demand are calculated using a rate set at 50% of BFI's total fueling service rate of \$4.66/GJ, or \$2.33/GJ (Clause 7.1 (c)).15 " (Exhibit B-1, p. 16)

42.1 Please explain how contract revenues in excess of the minimum take-or-pay are treated in the event that the buyout is not triggered.

Response:

Fueling station recoveries in excess of the minimum take or pay will be captured under the CNG & LNG Recoveries deferral account and amortized over a one year period through delivery rates flowing to non-bypass natural gas customers.

42.2 In the BFI Agreement, are there any benefits to the non-bypass customers from contract revenues in excess of the minimum take-or-pay amount, similar to the WM Agreement?

Response:

This response also addresses BCUC IR 1.42.4.

Both agreements contain similar treatment of revenues in excess of the take-or-pay volume. In both circumstances, the excess recoveries will be captured under the CNG & LNG Recoveries deferral account and amortized over a one year period through the delivery rates of non-bypass natural gas customers. Thus, the benefits to the non-bypass customers are similar.

With respect to the calculation of the excess rate, in the WM Agreement FEI negotiated an excess rate at 25% of the customer's base price (Section 7 (b) (iii)), whereas in the BFI Agreement FEI negotiated an excess rate at 50% of the customer's base price (Section 7.1 (c)). Therefore, the BFI Agreement provides the potential for a greater percentage of revenue benefits to all non-bypass customers.

Additionally, FEI expects BFI will receive gas service under Rate Schedule 25, which will generate delivery margin benefits of approximately $480,000 over the initial term of the seven year service agreement.

"8(c) An ongoing rate base deferral account to capture incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one year period, commencing the following year, to be effective as of January 1, 2012 pursuant to sections 59 to 61 of the Act." (Exhibit A2-10, Order G-128-11)

42.3 Please provide reasons for the difference in the treatment of actual volumes purchased in excess of minimum contract take or pay commitments between the proposed BFI Agreement and the approval in Order G-128-11.

Response:

Please refer to the response to BCUC IR 1.42.1 and 1.42.2.

There is no difference in the treatment of actual volumes purchased in excess of minimum contractual take-or-pay commitments with BFI as contemplated in Commission Order No. G-128-11. Excess fueling station recoveries will flow to natural gas customers throughout the term of the Agreement by way of the Commission approved CNG and LNG Costs and Recoveries deferral account.

42.4 Does FEI consider the treatment of contract revenues in excess of the minimum take-or-pay amount substantially different between the proposed BFI Agreement and the approved WM Agreement? Please explain why, or why not.

Response:

Please refer to the response to BCUC IR 1.42.2.

43.0 VARIATIONS IN THE TERMS OF SERVICE - UNDEPRECIATED CAPITAL COST

Reference: Exhibit B-1, Section 5.2, p. 16 and Appendix A, Schedule B

"7.1(c) if more than 5,000 GJ of CNG (the "Base Amount") is dispensed from the Fueling Station in any month, the rate payable for such CNG in excess of the Base Amount shall be the O&M Rate plus fifty percent (50%) of the Capital Rate. " (Exhibit B-1, Appendix A, p. 7, Section 7.1 (c))

43.1 Please complete the table below to show the reduction of the undepreciated capital cost if the monthly CNG dispensed in excess of the Base Amount. For example if BFI used 100 GJ/Month in excess of the Base Amount for 7.0 years, the calculation would be the following:

100 GJ/Month x 12 months / year x 7.0 years x (O&M Rate + 50 percent of Capital Rate)

Reduction of Undepreciated Capital Cost Due to Volumes in Excess of Base Amount

Excess GJ/Month	Undepreciated Capital Cost Reduction –Excess for Volumes for 7.0 Years	Undepreciated Capital Cost Reduction – Excess Volumes for 3.5 Years
100 GJ/month		
500 GJ/Month		
1,000 GJ/Month		
1,500 GJ/Month		
2,000 GJ/Month		
3,000 GJ/Month		

Response:

Please find the completed table below.

The charge applied to calculate the excess recoveries includes two components: the Capital component which is inflated by 2.00% each year and the O&M component which is inflated by BC CPI each year.

Reduction of Undepreciated Capital Cost Due to Volumes in Excess of Base Amount

Excess GJ/Month	Undepreciated Capital Cost Reduction – Excess for Volumes for 7.0 Years	Undepreciated Capital Cost Reduction – Excess Volumes for 3.5 Years
100 GJ/month	$24,939	$12,179
500 GJ/Month	$124,694	$60,896
1,000 GJ/Month	$249,388	$121,792
1,500 GJ/Month	$374,081	$182,688
2,000 GJ/Month	$498,775	$243,584
3,000 GJ/Month	$748,163	$365,377

43.2 Using the data from the Reduction of Undepreciated Capital Cost Due to Volumes in Excess of Base Amount Table, calculate the 2019 Undepreciated Capital Costs for the various excess volumes for 3.5 years.

Sensitivity of 2019 Undepreciated Capital Cost to Volumes in Excess of Base Amount for 3.5 Years

Excess GJ/Month	2019 Undepreciated Capital Cost –Excess for Volumes for 3.5 Years
100 GJ/month	
500 GJ/Month	
1,000 GJ/Month	
1,500 GJ/Month	
2,000 GJ/Month	
3,000 GJ/Month	

Response:

Please find the completed table below:

Sensitivity of 2019 Undepreciated Capital Cost to Volumes in Excess of Base Amount for 3.5 Years

Excess GJ/Month	2019 Undepreciated Capital Cost – Excess for Volumes for 3.5 Years
100 GJ/month	$1,114,718
500 GJ/Month	$1,066,001
1,000 GJ/Month	$1,005,105
1,500 GJ/Month	$944,209
2,000 GJ/Month	$883,313
3,000 GJ/Month	$761,520

43.3 Using the data from the Reduction of Undepreciated Capital Cost Due to Volumes in Excess of Base Amount Table, calculate the 2019 Undepreciated Capital Costs for the various excess volumes for 7.0 years.

Sensitivity of 2019 Undepreciated Capital Cost to Volumes in Excess of Base Amount for 7.0 Years

Excess GJ/Month	2019 Undepreciated Capital Cost –Excess for Volumes for 7.0 Years
100 GJ/month	
500 GJ/Month	
1,000 GJ/Month	
1,500 GJ/Month	
2,000 GJ/Month	
3,000 GJ/Month	

Response:

Please find the completed table below:

Sensitivity of 2019 Undepreciated Capital Cost to Volumes in Excess of Base Amount for 7.0 Years

Excess GJ/Month	2019 Undepreciated Capital Cost –Excess for Volumes for 7.0 Years
100 GJ/month	$1,101,958
500 GJ/Month	$1,002,203
1,000 GJ/Month	$877,509
1,500 GJ/Month	$752,816
2,000 GJ/Month	$628,122
3,000 GJ/Month	$378,734

44.0 PROJECT COST ESTIMATE AND FUELING SERVICE CHARGE PROPOSAL

Reference: Exhibit B-1, Section 5.1, pp. 15, 16

FEI states that: "This cost estimate has an accuracy range that is consistent with an Association for the Advancement of Cost Engineering ("AACE") degree of accuracy of Class 3."

44.1 Please describe and quantify the accuracy range of AACE Class 3.

Response:

According to AACE Cost Engineering terminology, Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. The typical level of project definition required to qualify as a Class 3 estimate is 10 to 40% of full project definition.

According to Jenmar Concepts, the Class 3 estimate for the BFI Project is largely based on unit cost line items obtained either from actual quotes or past experience on similar projects. Each line item corresponds to the layout defined in the preliminary site plan which contains a level of detail typical of the budget estimates Jenmar Concepts formulates. As such, the expected accuracy range for the Class 3 estimate for the BFI Project is between -10% and +20%.

44.2 Please provide 3 alternatives of Table 5 using 0%; 25%; and 50%; calculation rate for the revenues in excess of the minimum take-or-pay demand rate.

Response:

FEI interprets this question to mean a 0%, 25% and 50% increase in the volume as compared to minimum contract demand of 60,000 GJs per year. FEI assumes the 0%, 25% and 50% increase in volume is applied in each year, from 2012 to 2031. Please see Attachment 44.2 for the revised Table 5 for each scenario.

44.3 Please recalculate the termination fee based on 86 trucks being in service over the 7 and 10 year life of the contract.

Response:

Please refer to responses to BCUC IR 1.20.1.1 and 1.20.1.2 regarding the capital additions of the 86 trucks. No additional capital is required to service 86 trucks within the scope of this Project.

Table 5 below illustrates the termination fee over the 7 and 10 year life of the contract, assuming 86 trucks are in service from 2012 to 2019 (the 2018 column shows the 7 year term, and the 2021 column shows the 10 year term). Excess fueling station recoveries are assumed to be 40,000GJ per year (100,000GJ less minimum contract demand volumes of 60,000GJ) at the excess demand rate of $2.848/GJ (Exhibit B-1, Appendix A, p.7) for year 2012, inflated thereafter for the remaining years (O&M component by BC CPI inflation rate and Capital component by 2.00%).

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Approximate Contract Termination Fee
Table 5- 100 TJ per year demand
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Total Gross Plant in Service, Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
2	Accumulated Depreciation, Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)
3	Net Salvage, Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)
4	Deferral Account Repayment	Schedule 9, Line 37	39	30	27	25	22	14	-	-	-	-
5	Add: Removal Costs[1]											
6	Less: Excess Fueling Station Recoveries[2]		(114)	(230)	(349)	(470)	(593)	(719)	(847)	(971)	(1,094)	(1,217)
7	Total	Sum of Line 1 to Line 6	1,716	1,495	1,279	1,061	840	612	374	156	(62)	(280)
8	**Net Termination Payment[3]**		**1,716**	**1,495**	**1,279**	**1,061**	**840**	**612**	**374**	**156**	**-**	**-**
9												
10												
11		O&M Rate	1.033	1.054	1.076	1.098	1.12	1.143	1.166	1.189	1.214	1.238
12		Capital Rate	1.815	1.851	1.888	1.926	1.964	2.003	2.044	1.900	1.872	1.834
13		Total Charge	**2.848**	**2.905**	**2.964**	**3.024**	**3.084**	**3.146**	**3.210**	**3.089**	**3.086**	**3.072**
14												
15	Volume in Excess of Minimum Contract Demand		40	40	40	40	40	40	40	40	40	40
16												
17	1- Actual removal costs to be determined at time of contract termination and will be less the net salvage collected to date											
18	2- Cumulative fueling station recoveries received from volumes in excess of minimum contract demand											
19	3- Excess fueling station recoveries will be credited to a maximum amount of the net book value of the assets. That is, the net termination payment cannot be negative.											

44.3.1 Please describe the implications of a credit balance being built up in the termination fee and who those amounts would be credited to at the termination of the contract.

Response:

In the event there is a credit balance in the net termination payment, BFI would not pay a termination fee and the credit balance would remain as a benefit to the rate payers. Please see note 3 in the table in the response to BCUC IR 1.44.3.

In reference to BCUC IR 1.44.3, calculation of the termination fee based on 86 trucks in service over 10 years below shows a zero payment balance from BFI in years 2020 to 2021 as the excess fueling station recoveries more than offset the capital costs. That is, in this scenario if the contract was terminated in years 2020 and 2021, the credit balance in those years (Line 7 of the table in the response to BCUC IR 1.44.3) would remain for the benefit of rate payers.

The termination fee in each year reflects excess fueling station recoveries cumulative balance. It is only in the event that the buyout is triggered that the excess revenues will be used to offset the undepreciated capital cost of the fueling station.

44.4 Please describe the cost implications and risks to BFI, FEI, and FEI's natural gas ratepayers if volume drops to zero in the first five, ten, or fifteen years respectively.

Response:

Should the volumes drop in the first five years to zero, there will be minimum risk to FEI's natural gas ratepayers. Since this 7 year contract is based on a minimum take or pay, the costs will always be recovered. The only impact it will have on ratepayers is that they will receive no incremental benefit from the contract over the minimum take or pay volume..

Should the volumes drop in the first ten or fifteen years, FEI believes the contract will not be renewed between BFI and FEI after the initial 7 years of the contract as it will not be deemed beneficial. In accordance with Clause 11.1 of the BFI Agreement, the undepreciated capital cost of the fueling station will be recovered if the contract is terminated at the end of the first seven-year or after the initial term of seven years but prior to the 20th anniversary of the effective date.

45.0 COST OF SERVICE - O&M CHARGE

Reference: Exhibit B-1, Section 5.3.2, p. 18 and Appendix D

45.1 What safeguards, if any, are there that the $50,000 per year O&M estimate is sufficient to cover actual O&M costs for the fueling stations.

Response:

Section 12B of the GT&Cs does not require the recovery of the "actual O&M costs" per year. As the Commission recognized in the NGT Decision (at page 27), although recovery of "actual" O&M costs may be "ideal," the terms and conditions will ensure recovery "as close as possible" to the actual. FEI believes that indeed it is inefficient and impractical for FEI to adjust its fueling charge and amend service agreements with each customer after every contract year to account for actual O&M costs.

FEI believes the O&M cost estimate should be viewed similarly under the established cost of service ratemaking principles that apply to natural gas customers. This means rates are determined by taking the forecast delivery costs and dividing them by the forecast throughput volume. FEI has designed its O&M cost estimate as a forecast based on previous experience and a recommendation from its manufacturer (please see BCUC IRs 1.45.1.2 and 1.45.1.3). FEI believes that the BFI Agreement conforms to Section 12B of GT&Cs.

45.1.1 What requirements does Measurement Canada have that would be covered in this O&M estimate?

Response:

Requirements from Measurement Canada are limited to the calibration of the dispenser hoses. This activity needs to be conducted approximately every three years and is included in the O&M cost estimate of $50,000.

45.1.2 Please provide a breakdown of the $50,000 estimate of O&M costs based on "FEI's previous experience maintaining fueling stations."

Response:

FEI has used a cost assumption of $0.032 per diesel litre equivalent (DLE) to develop its O&M estimate based on its previous experience and a recommendation from a compressor manufacturer. This cost estimate includes:

- regular maintenance labor
- emergency call out labor
- regular preventative maintenance parts and general repair parts
- major overhauls
- recertification of relief valves – bi-annual typical
- regulatory inspections and permits
- communications lines (phone and internet)
- external contractors (control systems changes and electrical)
- emergency call for service operations
- waste oil and dryer water disposal

This cost assumption, multiplied by 1.5 million diesel litres (60,000 GJ) per year, results in an O&M charge of approximately $48,000, which has been increased to $50,000 per year in BFI's cost of service model.

As explained in BCUC IR 1.21.1, FEI has not concluded its RFP process, therefore the exact breakdown of this cost is not known. This will ultimately depend upon which compressor manufacturer is selected and their recommended monthly maintenance schedule. For the purposes of developing an O&M cost estimate for BFI, FEI has assumed the use of an IMW Industries compressor since FEI has experience with this equipment at the Waste Management fueling station.

45.1.3 Please provide the historical actual costs of maintaining Terasen Gas Inc.'s natural gas vehicle assets from 1995 to 2010.

Response:

FEI does not believe comparing CNG stations designed for heavy duty commercial vehicles to CNG stations designed for light duty vehicles is a reasonable comparison. The relative fuel capacity on these stations does not provide a close comparable (i.e. 2,000 GJs per year for a public light duty station versus 20,000 - 60,000 GJ per year for a heavy duty station).

Furthermore, the NGV assets during the period of 1995 to 2010 are not representative of the current generation of fueling station technology.

A more appropriate measure is the O&M costs incurred from the Waste Management station to date. For period from March 2011 to February 2012, Waste Management has incurred the following costs:

Activity	**Actual O&M Cost**
Call out soft start, install one excess flow valve, program mod with IMW, etc.	$2,609.60
Monthly maintenance	$567.84
Relocate fill post to center K-rail	$1,262.63
Call out no fill pressure, call out motor fault, monthly maintenance	$956.48
Monthly maintenance, call out for hose pull off, maintenance meeting call out fill valve	$1,255.55
Monthly maintenance, call out power lines, call out reset ESD	$1,165.92
Check and label fill valves & nozzles, Monthly maintenance	$1,333.84
Monthly maintenance, high suction shut down, high discharge shut down	$887.04
Monthly maintenance, change nozzle check modem	$1,087.52
Regenerate dryer, replace breakaway o-ring, maintenance change oil unit#2	$1,534.40
Oil change	$458.42
Total (Mar 2011 to Feb 2012)	**$13,119.24**

While this cost is not wholly indicative of costs at all future CNG fueling stations for heavy duty vehicles, it is a recent data reference point for FEI to assess its fueling station O&M charge. The total of $13,000 per year, divided by WM's fueling consumption from the past year of approximately 735,000 diesel litres, results in an estimate of $0.018 per DLE. This is significantly below the $0.032 per DLE used to calculate BFI's O&M cost estimate, primarily due to the fact the station is in its first year of operation.

Appendix D, page 2 lists $50,000 in "Contractor Costs" under the O&M cost heading.

45.2 Please confirm the allocation of FEI employee labour and contracted labour for this station.

Response:

During the initial years of operation, FEI expects the allocation will be 100% contracted labour for this station. As FEI adds additional CNG fueling stations and continues to gain experience, the Company plans to service these stations in-house, which may result in lower overall O&M costs. However, at this time FEI intends to use contracted labour to service its fueling stations, just as it has to maintain the Waste Management fueling station.

45.3 Please describe what Government or municipality charges give rise to the General School and Other and 1% in lieu of property taxes amounts?

Response:

Property tax expense is a function of revenues earned on gas consumed within municipal boundaries, property assessment values and property tax rates set by the various taxation authorities. Due to the movable nature of the CNG compression equipment, only assets that from the foundation or platform will be subject to assessment and any applicable municipal general, school and other mill rates. To determine the BFI fueling station charges, an average mill rate of 3.91% has been applied to the foundation gross plant in service value of $442 thousand resulting in forecast general, school and other taxes of approximately $17 thousand in the first year. To account for potential changes in mill rates, FEI has inflated this amount by 2 percent per year. Further, the revenue component of property taxes is expected to be applicable and is calculated by multiplying the second preceding year's revenues by one percent (i.e. 2014 expense = 2012 revenue x 1%), resulting in further property tax expense of approximately $2 thousand per year.

45.4 Given BFI pays property and other taxes, and the capital installation is on privately held lands, is a charge for property and other taxes included in the cost of service calculation appropriate?

Response:

Yes, it is appropriate to include property and other taxes in the determination of the cost of service because FEI will be assessed general, school and other taxes as well as the 1% in lieu associated with the fueling service provided to BFI. Although the capital installation is on privately held lands, FEI maintains ownership of the fueling station and thus will be assessed the applicable taxes.

BFI will review their annual assessments to ensure they are not assessed for the installation of the fueling station.

45.5 Has FEI contracted or hired (or plan to hire) any incremental additional staff as a result of the increased NGT activities?

Response:

FEI has not contracted or hired incremental staff as a result of providing CNG/LNG services and continues to operate under the O&M budgets set out in the 2012-2013 RRA.

46.0 COST OF SERVICE – APPLICATION COSTS

Reference: Exhibit A2-10, p. 28; Exhibit A2-4

"As discussed throughout these Reasons for Decision, the Commission Panel requires that to be approved, any General Terms and Conditions must include a cost of service calculation which reflects the actual full cost of service, including the cost of establishing, maintaining and promoting the program, as closely as possible. **The Commission Panel therefore directs that any revised General Terms and Conditions contain a provision whereby FEI will estimate the overhead and marketing expenses which relate to the CNG/LNG program and the expected CNG/LNG sales volume and allocate those costs in a reasonable manner among CNG/LNG customers going forward."** (Exhibit A2-10, p. 28)

"The non-rate base deferral account requested in Section 8.4, 1(b) of the Application is intended to capture the costs associated with the CNG and LNG Service Application. These costs consist of legal fees, intervener and participant funding costs, Commission costs, public notification costs and miscellaneous facilities, stationary and supplies costs. The amortization periods for deferral accounts that capture application costs range from 2 to 5 years and are largely dependent on the forecast costs of the application. TGI anticipates that the costs associated with this application will be in the range of $150,000 to $200,000 and therefore a three year amortization period is reasonable." (Exhibit A2-4)

46.1 Please provide the costs associated with this Application.

Response:

As discussed in the response to BCUC IR 1.46.2, FEI did not include Application costs in the determination of the BFI fueling station rates. In light of the volume of information requests pertaining to this contract and the registration of three interveners, FEI now expects the costs of the application to be approximately $75 thousand.

46.2 Have the cost of the Application been included in the cost of service calculation? Please explain why, or why not.

Response:

No, FEI did not include the cost of the Application in the cost of service calculation. FEI did not include Application costs because FEI did not expect the regulatory process that it is going through with respect to this application. The BFI Agreement was based on the approved Section 12B. Section 12B of the General Terms and Conditions was revised based on the Commission's NGT Decision and was approved for FEI's provision of fueling service to natural gas transportation. The regulatory costs and efforts that led to the NGT Decision and to establish the final approved GT&Cs were significant as many of the broader context issues and questions were raised and addressed in that process. Thus, FEI did not anticipate some of the same issues to be raised in this process.

Please also see the response to BCUC IR 1.47.2.

47.0 COST OF SERVICE – PROJECT TEAM

Reference: Exhibit B-1, Section 2.5, pp. 3- 4

FEI states that: "FEI's Project team consists of the following:

- FEI VP, Energy Solutions & External Relations – executive sponsor for the Project;
- FEI Project Manager – responsible for managing overall project milestones and budget from implementation to commissioning;
- NGT Sales Manager – responsible for customer relationship activities such as the delivery of FEI's service offering and contract negotiations;
- FEI Operations - responsible for asset management and performing ongoing maintenance of the fueling station."

47.1 Please provide an estimate of the amount of time each of the project team would have spent on this project thus far and the amount anticipated over the next year.

Response:

FEI does not track hours specifically spent on a project by project basis for the positions listed in the question. In addition, it is not possible to separate the hours spent on development of the project from the perspective of adding a new Rate Schedule 25 gas delivery account, from the hours spent on adding a new fueling station account. FEI's market development efforts take a holistic view of providing the customer with an end to end service package that meets the NGT customer's needs and provides benefits to FEI's overall system and to all its customers. The positions listed are all positions that exist as part of FEI's existing O&M budget and no incremental expenditures have been made to add staff to bring on NGT fueling station projects.

As a very rough estimate, time spent can be determined from the timeline of discussions with BFI. The City of Surrey announced its decision to award BFI the contract on December 14, 2011. A meeting was set up with BFI for January 6 to present FEI's approach to providing an end to end CNG fueling service to BFI. On January 9, a proposal was submitted to BFI. Discussions regarding the scope and negotiation of the agreement continued through the month of January and the agreement was executed on January 31, 2012. During this time period the hours spent on the project for each position are roughly estimated below:

Position	Time Spent To Contract (hours)	Time expected for balance of year (hours)	Percent related to fueling station component	Additional Comments
VP Energy Solutions and External Relations	5	5	50%	Part of existing FEI O&M
FEI Project Manager	20	100	75%	Costs are Charged to project and recovered in rate
NGT Sales Manager	20	10	50%	Part of existing FEI O&M. 25% of the NGT sales manager's cost is also allocated out again to the fueling station service rate through the $0.20/GJ marketing overhead charge.
FEI Operations	1	10	50%	Covered by existing FEI O&M. Project specific costs recovered through O&M rate.

In summary, costs associated with the personnel listed are either charged to the project or covered under existing O&M budgets. FEI's existing O&M budgets include positions such as these that are responsible for developing NGT markets to the benefit of all FEI natural gas ratepayers. Development of NGT load is an activity that falls within this core responsibility regardless of whether there is a fueling station provided in the overall package or not. Incremental overhead costs associated solely to the fueling station agreements are minor in the context of the benefits generated to all ratepayers. As shown in the Application, the addition of 60,000 GJ of load to FEI's system through the BFI Agreement provides delivery margin benefits of approximately $84,000/year. In addition, the $0.20/GJ overhead charge contributes $12,000 per year (escalated by BC CPI per year) towards such costs for the life of the project, which is expected to be 20 years.

47.2 Should FEI's project team also include those individuals involved in the regulatory process such as preparing the Application, responding to IRs, preparing tariff schedules? Why or why not?

Response:

FEI has not included in the project team listed the personnel involved with the regulatory process, and believes that these individuals should not be included for the following reasons.

First, the BFI Agreement and other service agreements for CNG/LNG fueling services are and will be based on the approved GT&Cs 12B, revised following the Commission's NGT Decision. The regulatory review, in FEI's view, in the ordinary course, should be relatively straightforward.

Second, this Application has been complicated by other requirements such as the zero dollar CPCN threshold recently established in the AES Inquiry for this and all NGT projects. This is a departure from the previous $5 million CPCN threshold. It would be unfair to the customer to burden this Project with costs involved in this atypical process, while in the future this type of atypical cost may not be involved.

Third, FEI's existing O&M budgets include provision for the costs associated with personnel involved in the regulatory process. Obtaining regulatory approval in order to further market development is an activity that is included in the core O&M activities and will benefit all natural gas customers by ensuring that the utility adds new loads and finds new ways to use natural gas.. No additional personnel have been added to the organization in order to prepare the regulatory applications for NGT, so there are no incremental costs to recover above what is included in existing O&M budgets.

47.3 Please estimate the one-time project team costs, regulatory costs, and any other one-time costs.

Response:

FEI does not track hours spent on a project by project basis for its Project team with respect to responding to the regulatory process, therefore there are no specific one-time Project team costs. Please refer to BCUC IR 1.47.1 for additional discussion.

Regulatory costs as discussed in the response to BCUC IRs1.46.1 and 1.46.2 include one-time application costs of approximately $75,000. Due to the unexpected nature of the regulatory process, FEI believes that only two thirds or $50,000 of said costs can be attributed to the BFI Agreement. FEI estimates there are no other one-time costs generated by this Application.

47.3.1 Please indicate whether these costs have been included in the Application.

Response:

For the treatment of costs associated with the project team, please see the responses to BCUC IRs 1.47.1 and 1.47.2. For the treatment of regulatory application costs see the response to BCUC IR 1.46.2. FEI is not aware of other "one time" costs that are relevant to this project.

48.0 COST OF SERVICE – ASSET MANAGEMENT

Reference: 2012-2013 FEU RRA, pp. 161, 174

"Although Asset Management focuses largely on management of existing gas system assets, in the future it will increasingly need to manage new assets that are required to support such services as those offered through the natural gas vehicle ("NGV") and biomethane programs." (2012-2013 FEU RRA, p. 161)

The Asset Management group requires an analyst and assistant in 2012 ($160 thousand). Two assistants are required in 2013 ($140 thousand). These roles will support O&M, capital, sustainment planning and the NGV and biomethane programs. The existing and new assets require maintenance planning and administration to ensure ongoing safety, reliability and cost effectiveness. Asset Management must be adequately staffed with skilled personnel in order to manage the increased workload (new NGV and biomethane assets, internal reporting and data management to improve asset management) and meet customer and regulatory requirements. (2012-2013 FEU RRA, p. 174)

48.1 Please provide the Asset Management group O&M costs to support the management of new BFI CNG assets for 2012-2019 by year.

Response:

FEI wishes to clarify the second reference in the question preamble which is an excerpt from the original filing of page 174 of the 2012-2013 FEU RRA. On September 28th, 2011, FEI submitted Exhibit B-1-3 which amended page 174 of the 2012-2013 FEU RRA to exclude the references to NGT in the description of Asset Management costs, and Exhibit B-21 which reduced the capital, O&M, volume and revenue forecasts pertaining to CNG and LNG fueling stations, as a result of the NGT Incentives Decision.

Please also refer to the response to BCUC IR 1.45.2. The activities that would be performed by FEI's Asset Management group are included in the O&M costs described in that response, which are expected to be contracted out for the first few years of the agreement. After that time, the majority of these O&M activities will be carried out by FEI employees and are expected to remain at approximately $50 thousand per year (escalating by BC CPI each year), $1.5 thousand of which will pertain to Asset Management O&M costs per year for the BFI assets.

48.2 Have the cost of the Asset Management group O&M costs to support the management of new BFI CNG assets been included in the cost of service calculation? Please explain why, or why not.

Response:

Please see response to BCUC IR 1.48.1.

Yes, asset management costs are included in the $50,000 of O&M costs (escalated by BC CPI each year) that are embedded in the cost of service calculation. For the first few years of the agreement these asset management costs are contracted out but are expected to be incurred by the Asset Management group in future years.

49.0 COST OF SERVICE – CUSTOMER TRAINING

Reference: Exhibit B-1, Appendix A, p. 5

"6.5 Training.

(a) FEI shall provide operational and CNG safety training to the Customer, its employees, contractors and agents at Intervals to be determined by the parties, it being the intention that following Initial training by FEI upon installation of the Fuelling Station, the Customer will undertake the training Internally with FEI conducting remedial or refresher training from time to time."

49.1 Please provide the cost of giving operational and CNG safety training to BFI and its employees by year for 2012-2019 by year.

Response:

FEI's cost of providing CNG safety training to BFI will be incurred in 2012 during the commissioning phase of the CNG fueling station and is included in the capital cost of the fueling station. This training will be provided to BFI's CNG truck drivers regarding the safe handling and fueling of natural gas. The training falls into the category of Training and Documentation and includes development of operating procedures and training, development of emergency response plan, station O&M manuals, and field commissioning and training trip. The total cost of $7,200 (60 hours @ $120/hr) is embedded in the $1.9 million capital cost.

As stated in the BFI Agreement, the customer will undertake internal training after 2012. If BFI requires refresher training, FEI will conduct short one or two hour sessions for the customer and allocate to general O&M as NGT market development activities.

49.2 Have the cost of the CNG safety training been included in the cost of service calculation? Please explain why, or why not.

Response:

Please refer to the response to BCUC IR 1.49.1.

50.0 COST OF SERVICE – CORPORATE BRANDING

Reference: Exhibit B-1, Appendix A, p. 4; Retail Markets Downstream of the Utility Meter (RMDM) Guidelines, p. 8

"5.6 Corporate Branding. In addition to any signage or notices installed pursuant to section 5.5, FEI shall be entitled to affix Its corporate logo and other branding and/or marketing elements to the exterior of the Fueling Station and decals to the exterior of Vehicles Identifying the Vehicles as powered by Natural Gas by FEI, all of reasonable size and prominence, but In no event any larger than 60 cm long by 15 cm high."

"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" (RMDM Guidelines, p. 8)

50.1 Please provide the cost of affixing the corporate logo and other branding and/or marketing elements to the exterior of the Fueling Station and decals to the exterior of the 52 Vehicles. Please separately identify each cost.

Response:

The cost of affixing a decal to the fueling station is estimated at $265 based on the experience with Waste Management. Costs for the decals to be placed on all 52 trucks is estimated at $2,500 based on experience with the Vedder project. These costs are covered in FEI's general communications budget. FEI would wish to raise awareness of the use of natural gas in these vehicles regardless of whether FEI was providing the fueling service or not. The load building benefits of adding BFI's NG trucks is estimated at $84,000 per year which will benefit all natural gas customers. Making other customers aware of the use of natural gas in heavy duty transportation could lead to interest from other trucking fleets and potentially additional throughput and revenue benefits for all customers. Therefore, these investments are viewed as being reasonable and should be recovered from all customers.

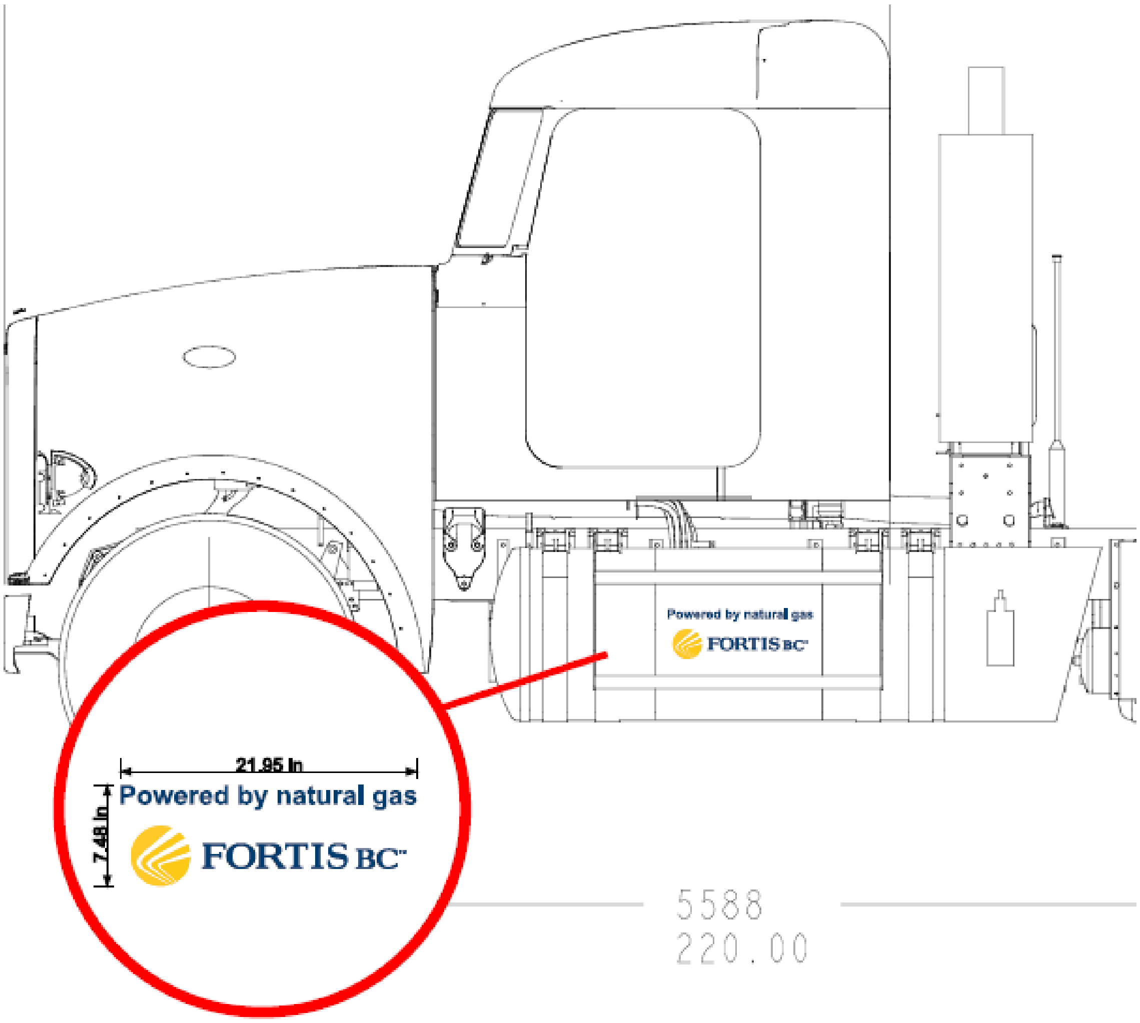
50.2 Please provide examples of the corporate logo and other branding and/or marketing elements.

<u>Response:</u>

As FEI owns the fueling assets, it is appropriate to have the assets identified as FEI property. This is important with respect to emergency response. It is also important to protect the legal title interests of FEI when attaching assets to a third party's property.

Decaling for the fueling station is shown below:

Decaling for the trucks will be comparable to the decals placed on the Vedder trucks as shown below:



50.3 Are the cost of the corporate logo and other branding and/or marketing elements recovered from NGV customers, all FEI customers, or the shareholder? Please explain.

Response:

The costs associated with the decals on the fueling station and trucks are part of FEI's general O&M budget which is recovered in delivery rates charged to all customers. FEI believes that this cost treatment is appropriate as these activities are part of FEI's general activities to communicate and support the use of natural gas as a transportation fuel, which will bring benefits to all ratepayers. They are not specific to FEI providing a CNG fueling station service.

50.4 Given that ratepayers do not own a public utility's corporate name and the corporate name is goodwill which is owned by the company, should corporate branding be a shareholder cost? Please explain why, or why not.

Response:

No, corporate branding should not be a shareholder cost. A utility's goodwill is the intangible value of its ongoing business, associated with or resulting from its performance and reputation with its customers. Ownership of the corporate name and goodwill, similar to ownership of other assets, is not determinative as to who should pay for costs associated with benefits or values received from the asset. A public utility's corporate name and goodwill provide benefits to all ratepayers.

50.5 Have the cost of affixing the corporate logo and other branding and/or marketing elements to the exterior of the Fueling Station and decals to the exterior of the 52 Vehicles been included in the cost of service calculation? Please explain why, or why not.

Response:

The cost of the decals has not been included in the Cost of Service calculation for the fueling station. The costs are not material in the context of the $1.86 million capital budget. In addition, the only cost that is relevant to the fueling station element on its own is the $265 cost for the decal on the station. The other decals relate to the use of natural gas in the vehicle, not directly to FEI's provision of CNG fueling service, hence they are more appropriately covered under FEI's general communications budget.

See also the response to BCUC IR 1.50.1.

51.0 COST OF SERVICE - MARKETING COST ALLOCATION

Reference: Exhibit A2-10, p. 28; Exhibit B-1, Section 5.3.3, pp. 19-20; Exhibit A2-1, p. 15

"As discussed throughout these Reasons for Decision, the Commission Panel requires that to be approved, any General Terms and Conditions must include a cost of service calculation which reflects the actual full cost of service, including the cost of establishing, maintaining and promoting the program, as closely as possible. **The Commission Panel therefore directs that any revised General Terms and Conditions contain a provision whereby FEI will estimate the overhead and marketing expenses which relate to the CNG/LNG program and the expected CNG/LNG sales volume and allocate those costs in a reasonable manner among CNG/LNG customers going forward.**" (Exhibit A2-10, p. 28) Underlined for emphasis.

"FEI believes a reasonable cost allocation for overhead and marketing recovered under Section 12B of FEI's GT&Cs should be limited to the cost associated with adding a new CNG/LNG fueling service customer.23

FEI estimates that its NGT Sales Manager24 dedicates 25 percent (or 0.25 FTE) of their time signing up new CNG/LNG customers.

... Under the BFI Agreement, the total overhead and marketing charge ($0.20 per GJ x 60,000 GJ) is $12,000 per year, or $84,000 over the 7 year contract term. FEI believes this is a reasonable allocation given BFI is already a commercial gas customer under FEI's Rate Schedule 2 – Small Commercial." (Exhibit B-1, pp. 19-20)

51.1 Please provide the latest NGV/NTG marketing plan.

Response:

Please refer to Attachment 51.1. It is part of FEI's existing communication plan.

51.2 Please identify where (Schedule and line number) the $12,000/year of overhead and marketing cost are included in Appendix D – Financial Schedules.

Response:

The $12,000/year recovery of overhead and marketing is included as a component of the annual forecast revenue in Appendix D, Schedule 11, Line 29 since it is included in the rate (see Line 27).

The $0.20/GJ charge for overhead and marketing expenses as described in Section 5.3.3 is similar to a rate rider. To further clarify, the Capital and O&M components of the fueling charge are determined by the cost of service model (i.e. like the delivery charge for natural gas customers) and the charge for overhead and marketing is calculated separately (i.e. similar to the determination of the RSAM Rate Rider for natural gas customers).

51.3 Please explain how the 25 percent allocation of NGT Sales Manager cost was determined to be a reasonable cost allocation for overhead and marketing related to the CNG/LNG program.

Response:

The overhead and marketing costs allocated to CNG and LNG fueling station customers should reflect the overhead and marketing costs associated with providing fueling station service. FEI believes that using a portion of the NGT Sales Manager's cost is a reasonable allocation for overhead and marketing pertaining to the CNG/LNG fueling station program because it isolates the approximate costs associated with adding new and supporting existing fueling station customers. The NGT Sales Manager position was formerly titled the Commercial and Industrial ("C&I") Sales Manager. The C&I Sales Manager position has existed within FEI for a number of years and has been included in general O&M. The NGT Sales Manager's role is primarily about building awareness and NGT load on the system and would exist regardless of whether or not FEI was involved in providing fueling station service. Thus, FEI does not believe that it is fair or appropriate to allocate 100 percent of the costs associated with the NGT Sales Manager to FEI fueling station customers.

To determine an appropriate allocation, the activities of the role were reviewed and identified as:

- Promoting interest and market awareness of natural gas as a transportation fuel;
- Participating in industry groups such as the Canadian Natural Gas Vehicle Alliance;
- Supporting sales of natural gas for transportation applications under Rate Schedules 6, 23, 25 and 16;

- Promoting FEIs service offering with respect to fueling stations; and,
- Resolving ongoing service and support issues with respect to FEIs overall NGT services.

While FEI does not track time spent on each of the above elements, the NGT Sales Manager estimates that approximately 25 percent of his time is spent dealing with the fueling station sales component of the job.

Table I-11: O&M Cost Estimate for 2010 and 2011

Department or Activity	2010		2011	
	FTE	Cost Estimate	FTE	Cost Estimate
Business Development Managers	1.3	$148,836	1.3	$156,241
Energy Products and Service Manager, Commercial & Industrial Sales, Project Manager	2.7	$331,439	2.7	$345,396
Customer Education	N/A	-	N/A	$50,000
Total:	4.0	$480,275	4.0	$551,637

(Exhibit A2-1, p. 15)

51.4 Please provide the job descriptions for each of the employees listed in the table above.

Response:

Please refer to Attachment 51.4.

51.5 Please add columns to Table I-11 to show the 2012 and 2013 O&M costs and FTEs.

Response:

FEI has submitted this response confidentially as the 2012 and 2013 cost estimate for labour is derived from the FEU's 2012-2013 RRA, Confidential version at page 147. FEI's Customer Education cost is detailed in our response to BCUC IR 1.51.1.

51.5.1 Please provide a breakdown of the 2012-2013 NGV Department between adding a new CNG/LNG fueling service customers and maintaining the existing customer base by year. Also explain how the breakdown was determined.

Response:

FEI does not have an "NGV" Department. The positions described above are roles associated with the general FEI business and which are covered under FEI's existing O&M budgets as submitted under the FEU's 2012-2013 Revenue Requirement Application.

Regarding allocation of costs to activities, provision of fueling service is just one link in the chain required to develop NGT markets. Other links in the chain are supply of commodity and supply of natural gas delivery services. Expenditures FEI is making to develop the NGT market, such as the NGT Sales Manager's costs and the Business Development costs should not all be attributed to the fuelling station cost of service but are more appropriately covered by the overall FEI budgets for these areas.

FEI has had NGT Sales and Business Development costs such as those listed in Table I-11 in its regular O&M budgets for many years and this is regular business for the utility in support of Rate Schedules 6, 23, 25, and 16. FEI would make such expenditures regardless of whether we are building fuelling stations.

By expanding its services to provide the missing element in the NGT market development chain (the fueling service) FEI is increasing the effectiveness of its overall NGT market development efforts. The resulting increase in business is now providing significant returns on the investment for the benefit of all customers. The BFI contract alone will contribute $84,000 per year in delivery margin benefits for all customers.

With respect to the cost of maintaining existing customers versus adding new NGT customers, the costs shown in the revised Table I-11 (see response to BCUC IR 1.51.5) will be incurred by FEI whether additional NGT <u>fueling station</u> customers are added or not. As stated in FEU's September 12, 2011 Evidentiary Update to the 2012-2013 RRA, FEI did not anticipate adding additional NGT customers in 2012 and 2013[14] due to Commission Order No. G-145-11 which determined EEC incentives for purchasing NGT were no longer available. Therefore the revised Table I-11 reflects the expected breakdown for 2012-2013 at this time. FEI does not expect that the addition of incremental NGT fueling station customers in 2012 and 2013 will significantly change the costs shown in Table I-11. To the extent that there are additional incremental costs associated with the fueling station agreements, such costs will be recovered from NGT fueling station customers through the $0.20/GJ additional Overhead and Marketing Charge that is built into the O&M rate for NGT fueling station customers.

51.6 Please complete the table below.

FEI NGV Customers and Volumes

Year	2010	2011	2012	2013
Number of Rate 6 NGV Customers				
Number of Tariff Supplement NGV Customers				
Total NGV Customers				
Rate 6 NGV Volumes (GJ)				
Tariff Supplement NGV Volumes (GJ)				
Total NGV Volumes (GJ)				

Response:

Please find the completed table below:

[14] This volume includes a permanent LNG refueling station at Vedder and CNG fueling station at Kelowna School District. FEI expects to file CPCNs for both these projects in the coming months.

FEI NGV Customers and Volumes

Year	**2010**	**2011**	**2012**	**2013**
Number of Rate 6 NGV Customers	21	19	21	21
Number of Tariff Supplement NGV Customers	0	1	4	4
Total NGV Customers	21	20	25	25
Rate 6 NGV Volumes (GJ)	66,048	64,102	56,400	56,400
Tariff Supplement NGV Volumes (GJ)	0	24,572	163,489	267,000
Total NGV Volumes (GJ)	66,048	88,674	219,889	323,400

In completing this table FEI has used the following assumptions:

- 2010 and 2011 Rate 6 NGV Volumes and number of customers are actuals which include Inland and Lower Mainland customers.
- 2012 and 2013 Rate 6 NGV Volumes and number of customers are based upon FEU's 2012-2013 RRA September 12, 2011 Evidentiary Update, Schedule 14 line 14 and Schedule 16 line 14 respectively.)
- 2011 Tariff Supplement NGV Volumes reflect Waste Management's actual CNG fueling station.
- 2012 Tariff Supplement NGV Volumes are explained in Exhibit B-1 at page 19.
- 2013 Tariff Supplement NGV Volumes includes Waste Management (30,000 GJ), Kelowna School District (5,000 GJ), BFI (60,000 GJ) and Vedder Transport (172,000 GJ) for a total of 267,000 GJ.

As stated in FEU's September 12, 2011 Evidentiary Update to the 2012-2013 RRA, these forecasts were premised on no availability of incentive funding for vehicles. The forecast in the table above does not include potential volume sales to approved third parties who could fuel at FEI's existing CNG/LNG fueling stations (Tariff Supplement customers) if approved by the host fleet and the Commission.

51.7 Please complete the table below using data from the previous table. Calculate Rate 6 and Tariff Supplement NGV customers and volumes as a percentage of the total NGV Customers and Volumes.

FEI NGV Customers and Volumes - Percentage Breakdown

Description	2010	2011	2012	2013
Number of Rate 6 NGV Customers				
Number of Tariff Supplement NGV Customers				
Total NGV Customers	100%	100%	100%	100%
Rate 6 NGV Volumes				
Tariff Supplement NGV Volumes				
Total NGV Volumes	100%	100%	100%	100%

Response:

Please find the completed table below:

FEI NGT Customers and Volumes - Percentage Breakdown

Description	2010	2011	2012	2013
Number of Rate 6 NGT Customers	100%	95%	84%	84%
Number of Tariff Supplement NGT Customers	0%	5%	16%	16%
Total NGT Customers	100%	100%	100%	100%
Rate 6 NGT Volumes	100%	72%	26%	17%
Tariff Supplement NGT Volumes	0%	28%	74%	83%
Total NGT Volumes	100%	100%	100%	100%

The percentage breakdown of Rate Schedule 6 NGT Volumes (17% in 2013) to Tariff Supplement NGT Volumes (83% in 2013) in this revised table does not reflect the overall impact to FEI's natural gas ratepayers with respect to cost allocation. The sales volumes in 2012 and 2013 are generated from FEI's four NGT customers (WM, BFI, KSD, Vedder) which require minimal incremental O&M expenditures to maintain (outside of fueling station O&M costs which are recovered from the customer through their fueling rate). The delivery margin revenue benefits generated from 267,000 GJ of NGT load creates delivery margin benefit exceeding

$400,000 in 2013[15], based on minimum take or pay volume commitments. FEI's natural gas ratepayers will receive these benefits with minimal additional risk as FEI has service agreements with these four customers. FEI estimates these sales volumes (and delivery margin revenue benefits) will increase substantially with availability of vehicle incentives for NGT. FEI has forecast this scenario in the response to CEC IR 1.5.1.

51.8 Please complete the table below allocating the NGV O&M costs based on percentage of Total NGV Customers.

NGV O&M Cost Allocated Based on the Percentage of Total NGV Customers

	2010	2011	2012	2013
Rate 6 NGV Customers				
Number of Tariff Supplement NGV Customers				
	$480,275	$551,637		

Response:

Please see the completed table below:

NGV O&M Cost Allocated Based on the Percentage of Total NGV Customers

	2010	2011	2012	2013
Rate 6 NGV Customers	$480,275	$524,055	$478,293	$504,940
Number of Tariff Supplement NGV Customers	$0	$27,582	$91,103	$96,179
	$480,275	$551,637	$569,396	$601,119

15 High level calculations include WM $38,000, BFI $84,000, KSD $12,000 and Vedder $277,000. Please note that 2013 delivery rates for natural gas customers have been offset by CNG & LNG delivery margin recoveries of $593 thousand. Please refer to Table 5.5-8 (revised September 28th) of the 2012-2013 FEU RRA

51.9 Please complete the table below allocating the NGV O&M costs based on the percentage of Total NGV Volumes.

NGV O&M Cost Allocated Based on the Percentage of Total NGV Volumes

	2010	**2011**	**2012**	**2013**
Rate 6 NGV Volumes				
Tariff Supplement NGV Volumes				
Total	$480,275	$551,637		

Response:

Please find the completed table below:

NGV O&M Cost Allocated Based on the Percentage of Total NGV Volumes

	2010	**2011**	**2012**	**2013**
Rate 6 NGV Volumes	$480,275	$398,776	$146,046	$104,833
Tariff Supplement NGV Volumes	$0	$152,861	$423,350	$496,286
Total	$480,275	$551,637	$569,396	$601,119

52.0 COST OF SERVICE - MARKETING COST ALLOCATION

Reference: Exhibit B-1, Section 5.3.3, p. 19; Exhibit A2-2, p. 208

"[23]NGT activities such as customer education and long term business development are not directly related to the cost of adding incremental CNG/LNG customers such as BFI." (Exhibit B-1, Section 5.3.3, p. 19)

"The Market Development group identifies and develops new energy service products and initiatives such as FEI's biomethane and NGV fueling service initiatives." (Exhibit A2-2, p. 208)

52.1 Given that the Market Development group identifies and develops new energy service products such as FEI's NGV fueling service initiatives, please explain why business development costs are not related to adding incremental CNG/LNG customers such as BFI.

Response:

FEI maintains a business development group to ensure that the utility can and will adapt to changing market environments. It is crucial that the utility is able to develop the products and services that will be needed by our customer base. If this is not done, it is likely that customer loads will decline, forcing increases in delivery rate and impairing the long term viability of the utility. This scenario can be labeled a "death spiral" and has the potential to result in major economic hardship for FEI's customers. FEI has already seen declines in use per customer that are not being fully offset by new customer additions and believes that investment in business development is crucial for the benefit of all natural gas ratepayers.

The business development group is responsible for assessing potential development segments with a view towards identifying which areas/segments offer the best potential for development. At present one of the greatest opportunities appears to be in the NGT market, so resources are being used to develop this market, which will bring benefits to all natural gas customers.

As with any emerging market, market development costs can be high. If the benefits to the overall business are ignored and all costs are allocated onto the emerging market, the cost allocation will kill off the emerging market opportunity before it has a chance to develop into a sizeable contributor to the business. This would clearly be counter to natural gas ratepayers' interest. As initial market development costs benefit all customers, the costs should also be allocated to all customers. As FEI explained at page 41 of FEU's Final Submission in the AES Inquiry:

> *"The allocation of cost is a function of rate design, and the fundamental test employed in any rate design and mandated by the UCA is that public utility rates must not be unduly*

discriminatory or unduly preferential. There are also a variety of widely accepted rate design principles subsumed within this test that can assist the Commission in determining when rates are unduly preferential or discriminatory. An example is the principle of "cost causality", which provides that costs should be recovered from those who cause them to be incurred and benefit from them."

In the case of CNG/LNG fueling service, an appropriate cost allocation has been undertaken as the approved GT&C 12B followed from various determinations made in the NGT Decision to ensure that FEI's CNG service recovers, to the extent possible, the full cost of service from the customer.

Even if FEI were to make a decision to allocate all business development costs solely to the NGT segment, it is crucial to realize that provision of fueling stations is just one link in the chain required to develop NGT markets. Other links in the chain are supply of commodity and supply of natural gas delivery services. Expenditures FEI is making to develop the NGT market should <u>not</u> all allocate to the station cost of service.

FEI has had NGV market development expenditures in our regular O&M budgets for many years and this is regular business for the utility in support of Rate Schedules 6, 23, 25, and 16. FEI would make such expenditures regardless of whether we are building stations. For example costs incurred for the following activities would continue to be incurred even if FEI had not built fueling stations:

- membership in the Canadian Natural Gas Vehicle Alliance
- NGV marketing communications programs
- NGV sales costs
- NGV related Business Development staff costs

It is not fair or appropriate to now allocate all these costs to the fueling station link and ignore the fact that they are incurred for the overall chain of services being provided. To do so would unfairly burden the rates charged to the fueling station customer.

By providing a crucial link in the NGT market development chain (the fueling service), FEI is increasing the effectiveness of its overall market development efforts. The resulting increase in business is now providing significant returns on the market development investment for the benefit of all natural gas customers. The BFI contract alone will contribute $84,000 per year in delivery margin benefits for all customers.

53.0 COST OF SERVICE - PAYMENTS AND INVOICING

Reference: Exhibit B-1, Appendix A, Section 8, p. 7

53.1 Has FEI incurred any costs to modify the existing billing system to accommodate the billing of NGT customers? Has additional training or staffing been required?

Response:

FEI has not incurred costs to modify the billing system to accommodate NGT customers; nor has additional training or staffing been required in this area. There has been no need to adjust the billing system to accommodate NGT customers.

54.0 PROJECT COST ESTIMATE AND FUELING SERVICE CHARGE PROPOSAL

Reference: Exhibit B-1, Section 5.3.1, pp. 17, 18

54.1 Under what conditions would the Capital component of the fueling charge increase?

Response:

The BFI Agreement stipulates that the capital component of the fueling charge will increase if the actual fueling station construction costs are greater than 2 percent from the forecast of $1.885 million. That is, if actual construction costs are greater than $1.923 million, the capital component of the fueling charge will increase.

54.1.1 Would the Capital component of the fueling charge increase/decrease if the earned return went up or down or the capital structure of FEI changed?

Response:

Consistent with the WM Agreement (and addressed in response to the FEI CNG-LNG BCUC Confidential IR1, BCUC IR 1.12.7), the BFI fueling charge will not be adjusted to reflect changes in the approved return on equity, debt rates or capital structure during the term of the BFI Agreement. Thus, the capital component of the fueling station charge will neither increase nor decrease if the earned return goes up or down or the capital structure of FEI changes.

54.2 Please provide a sensitivity analysis of 50 basis point fluctuations in the earned return estimate and the subsequent impact on the fueling charge and calculations in Appendix D.

Response:

FEI interprets "50 basis point fluctuations in the earned return" in the question preamble to mean a 50 basis point fluctuation in the return on equity of 9.50%.

Per response to BCUC IR 1.54.1.1, fluctuations in the earned return would not impact the fueling charge as set out in the BFI Agreement. However, for the purpose of demonstrating the impact on the fueling charge of a 50 basis point fluctuation in the return on equity, we provide the following:

- A 50 basis point change in the return on equity used to determine the fueling station charge results in an approximate change to the levelized cost of service of $1.2 million over the term of the agreement (approximately $200 thousand per year) or a change of approximately $0.07/GJ to the capital component of the fueling charge.
- A 50 basis point increase (i.e. 10.0% return on equity) results in an increase to the fueling charge of $0.07/GJ from $3.63/GJ to $3.70/GJ and a 50 basis points decrease (i.e. 9.0% return on equity) results in a decrease to the fueling charge of $0.07/GJ from $3.63/GJ to $3.56/GJ.

The fueling charge in the Agreement was set using the current FEI approved ROE of 9.50%. There are no provisions in the Agreement to adjust for any changes in the ROE.

55.0 COST OF SERVICE – SENSITIVITY ANALYSIS

Reference: Exhibit B-1, Appendix D

55.1 Please update the Financial Schedules in Appendix D to reflect the following scenarios:

a. The initial number of trucks is 86 instead of 52
b. The number of trucks increases from 52 to 86 in Year 2
c. The number of trucks increases from 52 to 86 in Year 4
d. The number of trucks increases from 52 to 86 in Year 6

Also include electronic copies of the updated Financial Schedules.

Response:

As discussed in the responses to BCUC IR 1.20.1.1 and IR 1.20.1.2, the additional capital and O&M requirements associated with 86 trucks as compared to 52 is zero. As a result, none of the requested scenarios result in a change to the cost of service.

For Scenario A, FEI has assumed that the minimum contract demand would be set to reflect 86 trucks per year or 100 TJs per year. This increase in minimum contract demand results in a revised total fueling station charge of $2.88/GJ, or a decrease of $1.78/GJ as compared to the rate as filed. Please refer to Attachment 55.1(a) for the financial schedules and fully functioning excel spreadsheet.

With respect to Scenarios B through D, the changes contemplated in the scenarios do not result in any modifications to the fueling station charges because the contract does not contain a provision to revise the minimum contract demand during the contract term. That is, in each of these scenarios both the numerator (the costs) and denominator (the volume) used to determine the fueling station charges do not change from the version as filed. However, each scenario would result in recoveries in excess of minimum contract demand and as such the approximate contract termination fee (line 35 of Schedule 11 of Appendix D) is impacted. Please refer to Attachment 55.1(b), Attachment 55.1(c) and Attachment 55.1(d) for the financial schedules and fully functioning excel spreadsheets.

Please note that for additional clarity and purposes of this response, FEI has expanded the Contract Termination component of Schedule 11 as well as Termination Fee worksheet. Please also note that FEI assumes that in each scenario the number of trucks increased in any given year carries throughout the remaining years (i.e. Scenario (b) 86 trucks in Year 2 through to Year 20).

55.2 Please update the Financial Schedules in Appendix D to include following costs in the cost of service:

- The cost of the Application
- The cost of the Project Team
- The cost of NGV Asset Management O&M
- The cost of Customer Training
- The cost of Corporate Branding
- The cost of Payments and Invoicing

Also include an electronic copy of the updated Financial Schedule.

Response:

The following costs are included in Attachment 55.2 (Financial Schedules from Appendix D), unless otherwise stated:

- The cost of the Application: Please refer to BCUC IR 1.46.1. The cost of the Application is now expected to be approximately $75,000. For purposes of responding to this IR FEI has included two thirds of the forecast application costs identified in the response to BCUC IR 1.46.1, or $50 thousand. FEI believes that this would be an appropriate amount to include in the Financial Schedules (Schedule 9) considering the unexpected regulatory process for this Application. FEI has shown these costs as a deferral account amortized over the 7 year contract term.

- The cost of the Project Team: Please refer to BCUC IR 1.47.1. No changes required as these costs exist as part of FEI's existing O&M budget and no incremental expenditures have been made to add staff to bring on NGT fueling station projects.

- The cost of NGV Asset Management O&M: Please refer to BCUC IR 1.48.2. No changes required as these costs are embedded in the $50,000 Contractor O&M costs (Schedule 2, Line 9).

- The cost of Customer Training: Please refer to BCUC IR 1.49.1. No changes required as these costs are embedded in the Capital costs of $1.9 million (Schedule 6, line 2).

- The cost of Corporate Branding: Please refer to BCUC IR 1.50.1. No changes required as these costs are covered in FEI's general O&M budget.

- The cost of Payments and Invoicing: Please refer to BCUC IR 1.53.1. No changes required as no additional costs were incurred for this Application.

As a result of including the cost of the Application of $50,000, to be recovered over the life of the contract of 7 years, the Fueling Station charge is $4.744/GJ, an increase of approximately $0.08/GJ as compared to the rate of $4.663/GJ as filed, all else being equal.

Please refer to Attachment 55.2 for the financial schedules and fully functioning excel spreadsheet pertaining to this response.

56.0 COST MONITORING

Reference: Exhibit A2-10, pp. 30-31

"The Commission Panel is also concerned that the twenty year time horizon for the CNG assets is a lengthy time and FEI's proposed business model is therefore subject to the considerable uncertainty inherent in predictions of market forces a long time out. **Accordingly, the Panel directs FEI to keep the costs and revenues associated with the Waste Management Agreement and any other offerings separate and distinct and to monitor such offerings during a two year test period and provide a report by March 31, 2013. The scope of the report should include the topics listed in Appendix 2**."

56.1 Please explain how FEI is keeping the costs and revenues from the WM, BFI and other NGV offerings separate and distinct from other FEI costs and revenues.

Response:

FEI accounts for the costs and revenues pertaining to all NGT customers through the use of internal orders and work breakdown structure ("WBS") elements, thus maintaining a separation and distinction of NGT costs and revenues from all other FEI costs and revenues. Specifically,

- The capitalized costs for individual NGT customers are tracked using various service orders captured under a unique WBS element;
- The O&M costs are tracked separately per customer using internal orders; and
- Revenues are also tracked separately per customer using internal orders.

57.0 FEI GT&C SECTION 12B.4

Reference: Exhibit A2-10, p. 28; Exhibit A2-5, Section 12B.4

"As discussed throughout these Reasons for Decision, the Commission Panel requires that to be approved, any General Terms and Conditions must include a cost of service calculation which reflects the actual full cost of service, including the cost of establishing, maintaining and promoting the program, as closely as possible. **The Commission Panel therefore directs that any revised General Terms and Conditions contain a provision whereby FEI will estimate the overhead and marketing expenses which relate to the CNG/LNG program and the expected CNG/LNG sales volume and allocate those costs in a reasonable manner among CNG/LNG customers going forward.**" (WM and GT&C for CNG and LNG Decision, p. 28) Underlined for emphasis.

57.1 The FEI GT&C, Section 12B.4 does not specifically mention that the cost of service calculation should include the actual full cost of service, including the cost of establishing, maintaining and promoting the program, as closely as possible. In the interests of clarity, should FEI GT&C, Section 12B.4 be amended to comply with the WM and GT&C for CNG and LNG Decision? Please explain why, or why not.

Response:

No, the FEI GT&C, Section 12B.4 does not need to be amended as the GT&Cs resulted from a full regulatory proceeding and complies with the CNG and LNG Decision. Specifically, GT&C 12B addresses six specific items raised by the Commission in the CNG and LNG Decision (at page 30), in addition to the "take or pay" commitment. The GT&Cs 12B was approved on February 7, 2012 by Order G-14-12 and endorsed by Commission on March 2, 2012. Prior to the approval in February, FEI had discussions with, and worked with, Commission staff to have a proposed GT&C 12B that both parties agreed to be in compliance with the CNG and LNG Decision.

For clarity, Section 12.B3 specifies that "Customers will be charged a 'take-or-pay' rate (i.e. Minimum contract demand) under the Service Agreement that recovers the present value of the cost of service associated with provision of CNG or LNG Service over the term of the Service Agreement, as calculated pursuant to Section 12B.4". As the Commission stated in the CNG and LNG Decision (at page 25), the general terms and conditions are to assure that "the total actual cost of the refueling facility will be recovered from the CNG/LNG customer to the extent possible."

Further, Sections 12.B4, items (a) through (c) clearly identify the inclusion of the actual capital, O&M and other components of the cost of service which are embedded in the determination of the fueling station charges.

Finally, Section 12.B (d) addresses the requirement to include the cost of establishing, maintaining and promoting the fueling station program.

Thus, FEI believes that the recently approved existing GT&C, Section 12B appropriately allows recovery, to the extent possible, of the total actual cost of FEI's fueling service, including the cost of establishing, maintaining and promoting the program.

As discussed in the response to BCUC IR 1.52.1, the provision of the Fueling Station service is just one component of the overall NGT service chain. It is an important element but it is not the sole element. FEI has historically supported the NGT market application and incurred costs in doing so regardless of whether FEI is providing fueling stations.

Loading the COS calculation with all costs associated with "establishing maintaining and promoting" the overall NGT market (i.e. not just the costs associated with establishing, maintaining and promoting the fueling stations) will serve only to unfairly burden the NGT station offering and is inconsistent with the cost causation principle (e.g., all components of the NGT service chain should be allocated a portion of the total costs to establish, maintain and promote natural gas transportation / vehicle offerings). If all costs are included in the Fueling Station offering, it will result in making the service offering less competitive and will likely reduce the rate of market adoption. In this circumstance, FEI would not avoid costs and would also not receive the delivery margin benefits generated by the new business (BFI delivery margin benefits are calculated to be $84,000/year).

FEI believes it is reasonable to allocate any incremental costs that are related to "establishing, maintaining and promoting" the NGV stations to the NGV Station cost of service, but FEI believes there are no significant costs that are solely related to the addition of this service offering beyond those that are already captured in the $0.20/GJ rate element (i.e. Section 12B.4(d) of the GT&C) that is already built into the BFI agreement.

57.2 Should FEI GT&C, Section 12B.4 be declared interim pending the amendment to comply with the WM and GT&C for CNG and LNG Decision?

Response:

Please refer to the response to BCUC IR 1.57.1.

No, the FEI GT&Cs should not be declared interim because FEI believes that the existing Section 12B that was approved by Order G-14-12 is in compliance with the NGT Decision.

58.0 COST RECOVERY

References: Exhibit A2-10, pp. 17, 24, 28, 29; Exhibit A2-9, p. 12; AES Inquiry, Exhibit C17-4, BCUC 1.6.2, p. 4

The Panel on the CNG/LNG Service Proceeding found that " while the benefits of GHG emission reduction provides a justification for FEI's proposed NGV program, FEI's ratepayers must be insulated, to the greatest extent possible, from the <u>costs and risks</u> of the program." (Exhibit A2-10, p. 17, emphasis added)

The Reasons for Decision contained a number of concerns regarding adequate cost-recovery, including "the effect of unbudgeted costs, cost overruns and other factors that could require ratepayer subsidization... Any General Terms and Conditions must therefore include additional assurance that the total actual cost of the refuelling facility will be recovered from the CNG/LNG customer to the extent possible." (Exhibit A2-10, p. 24)

The cost of service calculation was to reflect "the actual full cost of service, including the cost of establishing, maintaining and promoting the program, as closely as possible; The Commission Panel therefore directs that any revised General Terms and Conditions contain a provision whereby FEI will estimate the overhead and marketing expenses which relate to the CNG/LNG program and the expected CNG/LNG sales volume and allocate those costs in a reasonable manner among CNG/LNG customers going forward." (Exhibit A2-10, p. 28)

Page 29 of the Reasons for Decision continued:

> "Given that FEI may be in competition with other non-regulated businesses, the Commission Panel is concerned about the potential for cross subsidization by FEI's existing ratepayers. The Panel considers that the public interest would not be served by effectively providing FEI with a competitive advantage over other potential participants in the industry by allowing FEI to subsidize the costs of what would otherwise be an unregulated service, with existing ratepayer money. This again supports the Panel's determination that, to the extent possible, the full cost of CNG and LNG service is to be recovered from the CNG and LNG customers, respectively."

Ferus LNG states in their evidence in the AES Inquiry that:

> "In order to avoid cross-subsidization of costs and risks, the regulation of Natural Unregulated Services should be conducted on a stand-alone basis ("Stand Alone Regulation") where existing ratepayers are fully insulated from the costs and

risks of the Natural Unregulated Services. Such an approach will allow the Commission to regulate where required to do so but in a manner that will preserve competition and the ability for markets to develop in sectors that are not natural monopolies." (Exhibit A2-9, p. 12)

In a response to a BCUC IR in the AES Inquiry, Clean Energy indicated that it "would prove very difficult for a utility to (price in the full cost of risk in setting a rate), particularly when cross-subsidies that are very hard to regulate come into play. In fact, it would prove very onerous for the Commission as it would require significant and continuous regulatory oversight and, as stated in our responses to 5.1 and 6.1 above, Clean Energy does not believe that there is any justification for any natural monopoly utility in any jurisdiction to re-enter (in the case of the FEU) and/or operate in what should be a fully transparent, un-regulated and non utility territory specific, competitive NGV market place." (AES Inquiry, Exhibit C17-4, BCUC 1.6.2, p. 4)

58.1 Given the potential difficulty of factoring in risk, avoiding unbudgeted costs, including the costs of establishing, maintaining and promoting the NGV program, and the presence of active competition in the NGV market, would it be more appropriate for NGV services to be offered by a regulated affiliate of FEI? Please discuss.

Response:

Before responding the information request, FEI would state that the "presence of active competition" is not borne out by the facts as there has not been a fueling station built in the Vancouver area in the last 10 years that was not an FEI station. In effect, the market has been dormant and has only come to life with FEI's participation.

No, FEI does not believe that it would not be more appropriate for NGV services to be offered to BFI by a regulated affiliate of FEI for the following reasons.

First, pursuant to the NGT Decision and Order G-14-12 that approved GT&C 12B, the Commission has determined that FEI can provide CNG service. The recently approved general terms and conditions are revised terms and conditions that followed from various determinations made in the NGT Decision to ensure that FEI's CNG service recovers, to the extent possible, the full cost of service from the customer.

Second, the CNG/LNG Fueling service is a natural gas service and therefore should not be considered any different than the existing natural gas class of service within FEI. Since natural gas is delivered in usable form, there is no compelling reason to treat this service differently than other commercial customers. Having NGV in a separate regulated affiliate would be similar to having each customer class in a separate corporate structure as a regulated affiliate.

Third, risk, budgeted costs as well as maintaining and promoting the NGV program are all cost elements that have been reflected in NGV customer rates and the apportionment of costs are based on the same concepts as the allocation of costs to customer classes such as residential, commercial and industrial. Creating a regulated affiliate simply adds an additional layer of costs but offers no additional tangible benefit to the customer being served or protection to non-bypass customers.

Fourth, in the AES Inquiry, the FEU have submitted that the Commission's ability to consider the presence of competition is circumscribed by the UCA. But in any event, the NGT Decision expressly referenced the presence of competition in the NGV market, and the Panel required modifications to the GT&Cs in recognition of competition.

The issues raised in the question are the subject matter of the AES Inquiry. Please see the response to BCUC IR 1.4.1 for further discussion of why the Commission should give effect to past decisions pending the outcome of the AES Inquiry.

However, it should be pointed out that FEI has a number of natural gas vehicle related tariffs that the Commission has recognized and approved over a number of years as follows:

<u>Rate 6</u> - Natural gas vehicle service rate for companies that retail natural gas to customers with natural gas vehicles or fleet customers that use natural gas for their own fleet

<u>Rate 6A</u> - Natural gas vehicle service rate for transportation use only to provide on-site vehicle fuelling services

<u>Rate 6P</u> - Compressed Natural Gas (CNG) fuelling service available to the general public at the FortisBC Energy Inc. Surrey Operations Centre.

<u>Rate 23</u> - Large commercial transportation rate for customers purchasing gas directly from a licensed marketer with consumption of greater than 2,000 GJ annually

<u>Rate 25</u> - General firm transportation service rate for large volume commercial, institutional, multi-family and other accounts purchasing gas directly from a licensed marketer with consumption of approximately 5,000 GJ or more annually.

<u>Section 12B (Vehicle Fueling Stations) of the General Terms and Conditions of Service</u> - allowing FEI to install, maintain and own a CNG/LNG compression, dispensing for compressed natural gas (CNG) fueling and fuel storage and Dispensing Service for Liquified Natural Gas feuling. FEI is allowed to charge a rate (cost of service recovery) based on a cost of service model calculated under the terms identified in the tariff.

Attachment 3.1

Clean Energy®

CLEAN ENERGY FUELS CORP.

2010 Summary Annual Report
and Form 10-K

CLEAN ENERGY is the largest provider of natural gas fuel for transportation in North America and a global leader in the expanding natural gas vehicle market. We have operations in CNG and LNG vehicle fueling, construction and operation of CNG and LNG fueling stations, compressor equipment and technology, biomethane production and vehicle conversions.

We fuel over 21,200 vehicles daily at 224 strategic locations across the United States and Canada with a broad customer base in the refuse, transit, trucking, shuttle, taxi, airport and municipal fleet markets.

Clean Energy del Peru, a joint venture, fuels vehicles at two stations and provides CNG to commercial customers in Peru.

We own (70%) and operate a landfill gas facility in Dallas, Texas, that produces renewable natural gas, or biomethane, for delivery in the nation's natural gas pipeline network. We are building a second facility in Michigan. We own and operate LNG production plants in Willis, Texas and Boron, Calif. with combined capacity of 260,000 LNG gallons per day and that are designed to expand to 340,000 LNG gallons per day as demand increases.

Northstar, a wholly owned subsidiary, is the recognized leader in LNG/LCNG (liquefied to compressed natural gas) fueling system technologies and equipment, station construction and operations. Northstar has built 70% of the LNG fueling stations in the United States.

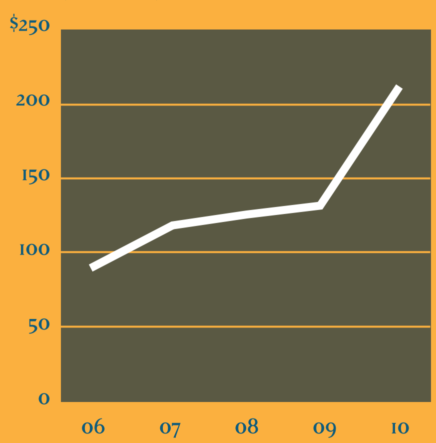
BAF Technologies, Inc., a wholly owned subsidiary, is a major provider of natural gas vehicle systems and conversions for taxis, vans, pick-up trucks and shuttle buses.

IMW Industries, Ltd., a wholly owned subsidiary based in Canada, is a global supplier of compressed natural gas equipment for vehicle fueling and industrial applications with more than 1,200 installations in 24 countries.

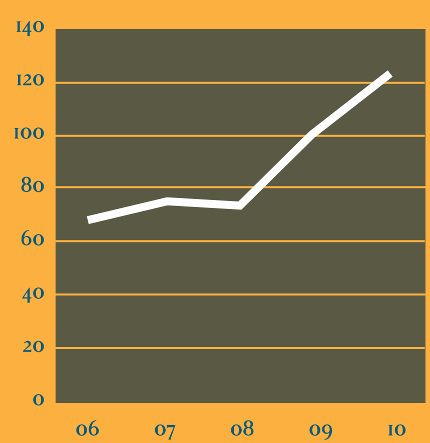
Natural gas is cleaner, cheaper and an abundant All-American resource, making it the compelling alternative to gasoline and diesel for transportation.

Nasdaq: CLNE
www.cleanenergyfuels.com

REVENUE
(MILLIONS)

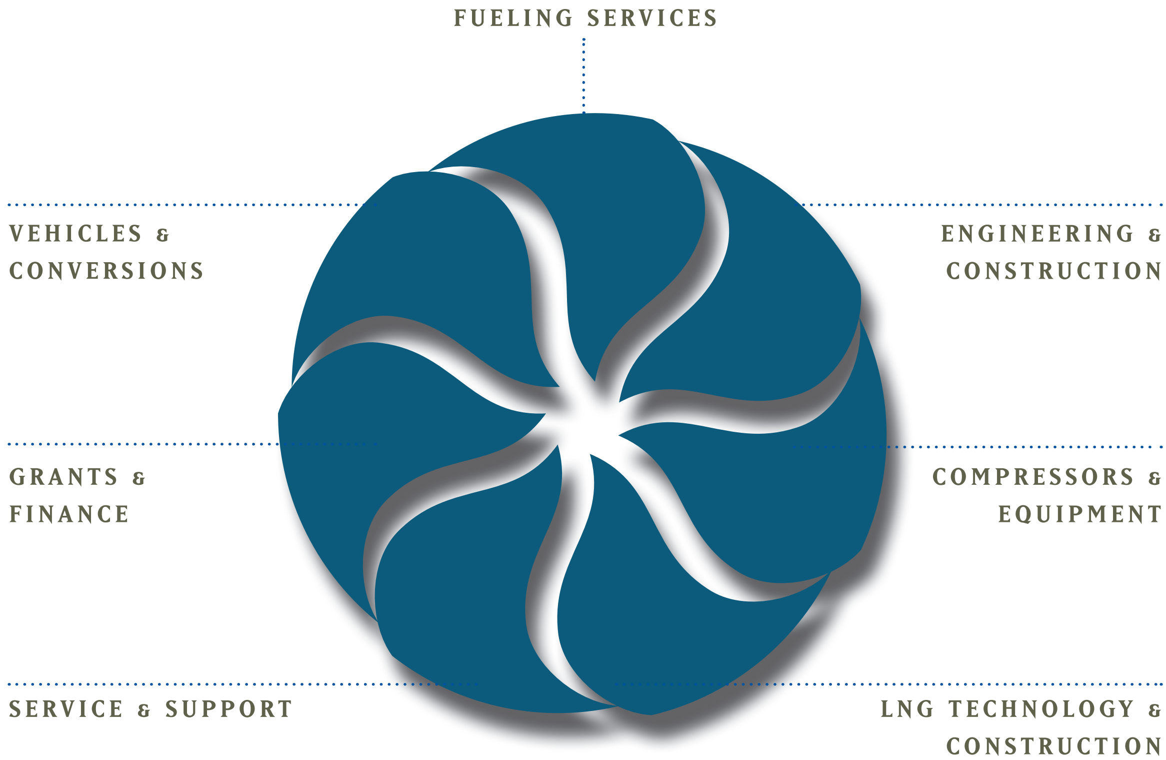


VOLUME OF GAS DELIVERED — CNG & LNG (MILLIONS OF GALLONS)



Please review the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission for information on the Company's results of operations and financial position.

CUSTOMER SOLUTIONS MATRIX



CLEAN ENERGY IS THE CONNECTION TO NATURAL GAS FUELING

We began our business in 1997 by offering our customers complete fueling services with long-term fuel contracts. As the industry has developed, there is greater understanding of natural gas fueling and diversity in implementation. ••• Today, our Clean Energy Customer Solutions Matrix enables any fleet customer to connect to natural gas fueling through Clean Energy and succeed no matter what services they seek — from turnkey solutions to equipment-only alternatives. ••• The Clean Energy Solution, our comprehensive package, provides integrated fueling services: turnkey station engineering/construction, compressors/equipment, service/support and grants/finance with fueling contracts. ••• Our individual customer solutions provide specific support. Some fleets may want to buy equipment only, or do their own operations and maintenance or monitoring. No matter. Clean Energy is there to help them convert to and succeed with natural gas fueling quickly, easily and affordably. ••• What has not changed is the reason to team with Clean Energy for natural gas fueling — because it's the best decision owners and operators can make to ensure that their vehicle fleets are fueled and roll out every day on time. In a word — reliability.

TO OUR SHAREHOLDERS

OUR 61% REVENUE GROWTH IN 2010 only begins to tell the story for the year. We expanded our business scope significantly, both in our domestic fueling services market and in the rapidly expanding international market with the addition of a leading provider of compressor equipment and technology. We also acquired the leader in LNG/LCNG technology, equipment and station design and construction.

In the United States, natural gas fuel is finally becoming acknowledged as clean, abundant, domestic and affordable — and more and more fleets are adopting it.

REVENUE FOR 2010 exceeded $210 million and total assets grew to $583.5 million, with $41.7 million in long-term debt at fiscal yearend. Combined CNG, LNG and biomethane volume increased 21% to more than 122 million gallons. At yearend, we were fueling 480 fleet customers and more than 21,000 vehicles at 224 strategic locations in North America. We completed 45 new stations or station upgrades. Please review our 2010 10-K in the following pages for detailed financial information.

TWO ACQUISITIONS AND A MASTER INFRASTRUCTURE AGREEMENT led the year's strategic activity. In September, we acquired IMW Industries, a leading international supplier of CNG compressors and other station equipment. Based in British Columbia, Canada, IMW has a second manufacturing facility in Shanghai, China, and 12 sales and service offices. It is one of the best known, most respected equipment suppliers with over 1,200 units installed in 24 countries. This positions Clean Energy soundly in the international market. It also provides us factory-direct sourcing and pricing for our station construction program in North America, enabling top-quality projects at competitive prices.

In October, we announced a master agreement with Pilot Flying J, the nation's largest operator of truck stops with 550 locations, to build and operate LNG fueling facilities on those stations where demand warrants. Access to this nationwide system provides Clean Energy with the ability to expand our truck fueling infrastructure rapidly along major goods movement corridors.

In December, we acquired Northstar, the pre-eminent company for LNG/LCNG technology and equipment, as well as station design, construction and maintenance. It has built 70% of the LNG fueling

THE CLEAN ENERGY SOLUTION

Integrated fueling services: Turnkey station engineering/construction, compressors/equipment, service/support, grants/finance with fueling contracts

FUELING SERVICES

With more than 14 years' experience, Clean Energy offers CNG, LNG and Biomethane under short- or long-term fueling contracts.

ENGINEERING & CONSTRUCTION

With numerous diverse stations built nationwide, Clean Energy provides best-practice approaches to each station project.

stations in the United States. Northstar will help build out our heavy-duty vehicle LNG fueling infrastructure in the Pilot Flying J network and at other locations.

CLEAN ENERGY BECAME A STRONGER COMPANY with these additions. We now are integrated and provide a comprehensive fueling service to our fleet customers — from station design, construction and equipment to fuel sales and maintenance and support services. We also have unbundled our natural gas fueling solution, as detailed on these pages, for those customers who seek to take a portion of the responsibility themselves.

This means that we are now positioned to respond to every business opportunity. If a prospective customer does not want the full Clean Energy Solution, then we can provide best-in-class services for the components they need.

- Fueling contracts
- CNG station engineering and construction
- CNG compressors and equipment
- LNG station construction and equipment
- Monitoring, service and support, 24/7
- Grant and financing assistance
- CNG vehicle conversions

CLEAN ENERGY IS THE CONNECTION FOR NATURAL GAS FUELING. Here's why. In the Transit sector, we now fuel over 5,500 buses daily. In the Refuse sector, we have more than 60 contracts with solid waste haulers in 16 states. In heavy-duty trucking, which is just ramping up, we fuel over 70% of the LNG-powered trucks currently on the road. We have operations at 23 airports serving a variety of fleets (taxis, shuttles, airport buses and service vehicles). We converted over 2,700 vehicles to natural gas in 2010, including fleets of vans for AT&T and Verizon. We have more than 400 service and support personnel in the field.

MOVING FORWARD, we were disappointed in 2010 when the Nat Gas Act, which was structured to help promote natural gas vehicle deployment in the United States, failed to move through Congress. There are many supporters in the House of Representatives and US Senate and it may come back in 2011. The legislation would be good to have since it would accelerate the deployment of vehicles, but our business is not dependent on it and we continue to move forward without it.

COMPRESSORS & EQUIPMENT

IMW

With more than 1,200 units in 24 countries, IMW is a global leader in CNG compressor and equipment design, manufacturing and installation.

LNG TECHNOLOGY & CONSTRUCTION

NORTHSTAR

Having installed 70% of the LNG fueling stations in North America, Northstar is the acknowledged leader in LNG/LCNG technology and construction.

SERVICE & SUPPORT

With more than 200 fueling stations monitored nationwide, Clean Energy Sentinel™ Service provides 24/7 monitoring and response.

Already, the refuse industry is converting to natural gas trucks across the country. The economics are clear. Large refuse fleet owners get payback for the incremental cost of the vehicles in less than a year due to the savings between the cost of natural gas fuel and diesel. After that, they should realize savings of up to $10,000 or more per year for the life of the truck, often up to 10 or more years. Likewise, large shippers and national fleets are beginning to appreciate the economics and, with more vehicle and engine types available, are beginning to switch from diesel to natural gas fuel for their fleets.

EXPANDING OUR COMMITMENT to biomethane, we formalized our operations in a new subsidiary called Clean Energy Renewable Fuels, which will manage our operations at the McCommas landfill site in Dallas, Texas, along with future biomethane production facilities that we start up or acquire. Our second biomethane production facility was initiated during 2010 as we signed a 30-year agreement with major solid waste operator Republic Services to purchase and sell renewable landfill gas recovered from Republic's 160-acre Sauk Trail Hills Landfill site in Canton, Michigan. While natural gas is 23% cleaner in carbon emissions than diesel in heavy-duty vehicles — and far cleaner in NOX and PM emissions — biomethane enables an 88% reduction in carbon emissions when displacing diesel.

IN SUMMARY, since the end of 2009, we grew from 229 employees and 10 sales offices across the United States to a total of 710 employees at the end of 2010 with operations and sales in 24 countries around the world.

Our business is well-diversified, but clearly focused on natural gas fueling for vehicles, and we are now structured to meet any customer's needs.

We credit our management team and staff at all levels for Clean Energy's strong performance and even stronger potential, and particularly recognize our outstanding Board of Directors for their insight and support of our goals.

ANDREW J. LITTLEFAIR
President and CEO

GRANTS & FINANCE

With more than $250 million secured, Clean Energy obtains valuable public/private financing for stations and fleets.

VEHICLES & CONVERSIONS

BAF

With more than 12,000 vehicles on the road, technology leader BAF provides qualified and certified conversions in all states.

THE CLEAN ENERGY SOLUTION

Integrated fueling services: Turnkey station engineering/construction, compressors/equipment, service/support, grants/finance with fueling contracts

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: December 31, 2010

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number: 001-33480

CLEAN ENERGY FUELS CORP.
(Exact name of registrant as specified in its charter)

Delaware	**33-0968580**
(State or other jurisdiction of incorporation)	(IRS Employer Identification No.)

3020 Old Ranch Parkway, Suite 400, Seal Beach CA 90740
(Address of principal executive offices, including zip code)

(562) 493-2804
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.0001 per share	The NASDAQ Global Market

Securities registered pursuant to section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐	Accelerated filer ☒	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the voting stock held by non-affiliates of the registrant as of June 30, 2010, the last business day of the registrant's second fiscal quarter, was approximately $600,161,508 (based on the closing price reported on such date by The NASDAQ Global Market of the registrant's common stock). Shares of common stock held by officers and directors and holders of 10% or more of the outstanding common stock have been excluded from the calculation of this amount because such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of March 7, 2011, the number of outstanding shares of the registrant's common stock was 70,253,554.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for the 2011 Annual Meeting of Stockholders are incorporated herein by reference in Part III of this annual report on Form 10-K to the extent stated herein.

CAUTIONARY NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements in this annual report on Form 10-K may constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based upon our current assumptions, expectations and beliefs concerning future developments and their potential effect on our business. In some cases, you can identify forward-looking statements by the following words: "may," "will," "could," "would," "should," "expect," "intend," "plan," "anticipate," "believe," "approximately," "estimate," "predict," "project," "potential," "continue," "ongoing," or the negative of these terms or other comparable terminology, although the absence of these words does not necessarily mean that a statement is not forward-looking. We believe that the statements in this annual report on Form 10-K that we make regarding the following subject matters are forward-looking by their nature:

- our ability to capture a substantial share of the significant anticipated growth in the market for natural gas as a vehicle fuel and to enhance our leadership position as that market expands;
- passage of government legislation and regulation providing incentives, including vehicle and fuel credits, for natural gas vehicle production and purchases and fuel use;
- plans to expand our station network and business with existing customers and to win business with new customers;
- potential acquisitions of natural gas reserves, including those found in shale reserves that are produced from hydrofracking, rights to natural gas production, and complementary businesses in the natural gas and biomethane fueling infrastructure, services and production industries;
- the success of our business of manufacturing and selling natural gas vehicle fuel compression equipment;
- our ability to sell biomethane we produce at prices that are at a premium to conventional natural gas prices;
- the success and expansion of our business of producing and selling biomethane derived from landfill gas;
- the success of our business of selling converted natural gas vehicles;
- our ability to successfully manage and integrate the operations of, and to implement effective controls and procedures over financial reporting at our recently acquired, wholly owned subsidiaries;
- estimated payments to former shareholders of recently acquired wholly owned subsidiaries in future years pursuant to the terms of the respective purchase agreements;
- anticipated revenue from continued sales by BAF to AT&T;
- expanding our sales in the regional trucking, ports, public transit, refuse hauling and airport markets;
- expanding our business into international markets;
- plans to expand our sales and marketing team and to hire sales experts to focus on targeted metropolitan areas and markets;
- our ability to capitalize on the cost advantages of natural gas as a vehicle fuel;
- plans to build additional natural gas fueling stations both under and not under contract;
- plans to participate in state and federal grant programs;
- plans to seek long-term LNG and CNG station construction, maintenance and fuel sales contracts with governmental bodies;

- growth in demand for LNG in the regional trucking and other fleet markets;
- expansion of our California LNG plant;
- anticipated production of biomethane at our DCE facility in 2011;
- developments and trends and opportunities for growth in the natural gas and fleet vehicle markets, including increased transition from diesel and gasoline powered vehicles to natural gas vehicles;
- impact of a significant increase in use of natural gas as a vehicle fuel on overall demand for natural gas supplies;
- more stringent emissions requirements continuing to make natural gas vehicles an attractive alternative to traditional gasoline and diesel powered vehicles;
- impact of more stringent ozone standards on the number of nonattainment areas in the U.S.;
- availability and performance of natural gas vehicles in our principal markets;
- anticipated federal and state certification of additional natural gas vehicles;
- expanded use of natural gas vehicles and sales of our fuel to trucks operating at the Los Angeles and Long Beach seaports and plans to model LNG truck deployment programs at other ports based on experiences at these seaports;
- future supply, demand, use and prices of crude oil and natural gas and fossil and alternative fuels, including gasoline, diesel, natural gas, biodiesel, ethanol, electricity, and hydrogen;
- prices for gasoline and diesel continuing to be higher than the price of natural gas as a vehicle fuel;
- estimated incremental costs, annual fuel usage, fuel costs, and annual fuel cost savings for vehicles using natural gas instead of gasoline or diesel;
- impact of environmental regulations and pressures on oil supply on the cost of crude oil, gasoline, diesel and diesel engines;
- impact of environmental regulations on the use of natural gas as a vehicle fuel;
- impact of general economic trends and budget deficits faced by many government entities on our business;
- the availability of tax incentives and grant programs that provide incentives for using natural gas as a vehicle fuel or purchasing natural gas vehicles;
- projected capital expenditures, project development costs and related funding requirements;
- plans to retain all future earnings to finance future growth and general corporate purposes;
- future margins on fuel sales;
- estimated costs to cover the increased price of natural gas above the inherent prices embedded in our customers' fixed price and price cap contracts;
- the development and introduction of additional natural gas engine platforms;
- plans to purchase futures contracts and to continue offering fixed price sales requirement contracts as appropriate and consistent with our revised natural gas hedging policy;
- ability to qualify all futures contracts as cash flow hedges;
- our LNG liquefaction plant in California enabling us to supply our operations in California, Arizona and other western U.S. markets more economically;

- costs associated with remaining in compliance with government regulations and laws;
- our ability to obtain waivers for breach of loan covenants;
- future asset retirement costs;
- future impairments of goodwill and other intangible asset balances;
- access to equity capital and debt financing options, including, but not limited to, equipment financing, sale of convertible promissory notes or commercial bank financing;
- the impact of federal tax credits on our business and stock price;
- our ability to appeal the IRS' disallowance of $5.1 million in certain excise tax credit claims and its impact on our business;
- the potential for a reduction in government incentives related to alternative fuels and vehicles and its impact on our revenue;
- the effect of volatility of natural gas prices on our business;
- our expectations regarding geopolitical risks and other risks commonly faced by companies with a global business model;
- our expectations regarding the importance of natural gas being widely accepted as a vehicle fuel;
- the impact of advancements in other alternative vehicle fuels and technologies and existing technologies on our business;
- the impact of take-or-pay supply agreements on our business;
- our ability to efficiently obtain CNG and LNG and its impact on our business;
- the potential for oil companies and natural gas utilities to enter the natural gas fuel market and impact our revenues;
- the potential for safety and environmental risks to impact our financial performance;
- the potential for a single large shareholder to exert significant influence over our corporate decisions; and
- our expectations regarding the relationship between natural gas futures contracts, our margin account and our cash balances.

The preceding list is not intended to be an exhaustive list of all of our forward-looking statements. Although the forward-looking statements in this annual report on Form 10-K reflect our good faith judgment, based on currently available information, they involve known and unknown risks, uncertainties and other factors that may cause our actual results or our industry's actual results, levels of activity, performance, or achievements to be materially different from any future results, levels of activity, performance, or achievements expressed or implied by these forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, those discussed in the "Risk Factors" contained in this annual report on Form 10-K. As a result of these factors, we cannot assure you that the forward-looking statements in this annual report on Form 10-K will prove to be accurate. Except as required by law, we undertake no obligation to update publicly any forward-looking statements for any reason after the date we file this annual Report on Form 10-K with the Securities and Exchange Commission, or to conform these statements to actual results or to changes in our expectations. You should, however, review the factors and risks we describe in the reports we will file from time to time with the Securities and Exchange Commission after the date we file this annual report on Form 10-K.

PART I

Item 1. Business.

Overview

We are the leading provider of natural gas as an alternative fuel for vehicle fleets in the United States and Canada, based on the number of stations operated and the amount of gasoline gallon equivalents of compressed natural gas ("CNG") and liquefied natural gas ("LNG") delivered. We offer a comprehensive solution to enable our customers to run their fleets on natural gas, often with limited upfront expense to the customer. We design, build, finance and operate fueling stations and supply our customers with CNG and LNG. We also sell non-lubricated natural gas compressors and related equipment used in CNG and LNG stations, convert light duty vehicles to run on natural gas, and produce renewable biomethane, which can be used as vehicle fuel or sold for other purposes. In addition, we help our customers acquire and finance natural gas vehicles and obtain local, state and federal clean air rebates and incentives. CNG and LNG are cheaper than gasoline and diesel vehicle fuel, and are well suited for use by vehicle fleets that consume high volumes of fuel, refuel at centralized locations, and are increasingly required to reduce emissions. According to the U.S. Department of Energy's Energy Information Administration (EIA), the amount of natural gas consumed in the United States for vehicle use more than doubled between 2000 and 2010. We believe we are positioned to capture a substantial share of the growth in the use of natural gas as a vehicle fuel in the United States given our leading market share and the comprehensive solutions we offer.

We sell natural gas vehicle fuels in the form of both CNG and LNG. CNG is generally used in automobiles, light to medium-duty vehicles, refuse trucks and transit buses as an alternative to gasoline and diesel. CNG is produced from natural gas that is supplied by local utilities to CNG vehicle fueling stations, where it is compressed and dispensed into vehicles in gaseous form. We are also beginning to provide CNG at some of our LNG stations by vaporizing the LNG and then compressing it to make liquefied to compressed natural gas ("LCNG"). LNG is generally used in trucks and other medium to heavy duty vehicles as an alternative to diesel, typically where a vehicle must carry a greater volume of fuel. LNG is natural gas that is super cooled at a liquefaction facility to −162 degrees Celsius (−260 degrees Fahrenheit) until it condenses into a liquid, which takes up about 1/600th of its original volume as a gas. We deliver LNG to fueling stations via our fleet of 58 tanker trailers. At the stations, LNG is typically stored in above ground containers until dispensed into vehicles in liquid form.

We serve fleet vehicle operators in a variety of markets, including public transit, refuse hauling, airports, taxis, seaports, and regional trucking. We believe these fleet markets will continue to present a high growth opportunity for natural gas vehicle fuels. We generate revenues primarily by delivering CNG and LNG to our customers, and to a lesser extent by building CNG and LNG fueling stations, selling renewable biomethane produced by our landfill gas joint venture, converting natural gas vehicles, selling natural gas vehicle fuel compression equipment, and financing vehicle acquisitions by our customers. We serve approximately 480 fleet customers operating over 21,270 natural gas vehicles. We own, operate or supply 224 natural gas fueling stations in Arizona, California, Colorado, District of Columbia, Florida, Georgia, Idaho, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Rhode Island, Texas, Virginia, Washington, and Wyoming, within the United States, and in British Columbia and Ontario within Canada.

In April 2008, we opened our first compressed natural gas station in Lima, Peru through our joint venture, Clean Energy del Peru. In August 2008, we acquired 70% of the outstanding membership interests of Dallas Clean Energy, LLC ("DCE"). DCE owns a facility that collects, processes and sells renewable biomethane collected from a landfill in Dallas, Texas. On October 1, 2009, we acquired 100% of BAF Technologies, Inc. ("BAF"), a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles. On September 7, 2010, we acquired the advanced, non-lubricated natural gas fueling compressor and related equipment manufacturing and servicing business of I.M.W. Industries Ltd., a British Columbia corporation ("IMW"). On December 15, 2010, we acquired 100% of the equity interests of Wyoming Northstar Incorporated, Southstar LLC, and M&S Rental LLC (collectively "Northstar"), which is a leading provider of design, engineering, construction and maintenance services for LNG and LCNG fueling stations.

We own and operate an LNG liquefaction plant near Houston, Texas, which we call the Pickens Plant, that is capable of producing up to 35 million gallons of LNG per year. We also own an LNG liquefaction plant in Boron, California, that is capable of producing 60 million gallons of LNG per year, with the ability to expand production up to 90 million gallons of LNG per year.

The Market for Vehicle Fuels

According to the EIA's Annual Energy Outlook 2011 Early Release (December 16, 2010), the United States consumed an estimated 176 billion gallons of gasoline and diesel in 2010, and demand is expected to grow at an annual rate of 0.4% to 194.1 billion gallons by 2035. These projections are lower than previously reported, but reflect the future impact of new federal regulations regarding fuel economy for vehicles. Gasoline and diesel comprise the vast majority of vehicle fuel consumed in the United States, while CNG, LNG and other alternative fuels represent less than 3% of this consumption, according to the EIA. Alternative fuels, as defined by the U.S. Department of Energy ("DOE"), include natural gas, ethanol, propane, hydrogen, biodiesel, electricity and methanol.

Through the summer of 2008, domestic prices for gasoline and diesel fuel increased significantly, largely as a result of higher crude oil prices in the global market and limited refining capacity. Crude oil prices were affected by increased demand from developing economies, such as China, India and the Middle East, global political issues, weather related supply disruptions and other factors. However, the global recession in 2008 through 2009 brought about a decline of world oil prices. As world economic growth has resumed and political instability has swept the Middle East, oil, gasoline, and diesel prices have again increased, with prices for a barrel of crude topping $100 a barrel in February 2011.

Higher oil, gasoline and diesel prices improve the magnitude of the immediate market opportunity for alternative fuels. Increasingly stringent federal, state and local air quality regulations, a desire to lower greenhouse gas emissions, and regulations mandating low carbon fuels continue to develop, and the need for fuel diversity further represents an opportunity for alternative fuels in the United States and Canada. Natural gas as an alternative fuel has been more widely used for many years in other parts of the world such as in Europe and Latin America, based on the number of natural gas vehicles in operation in those regions. The February 2011 edition of the Gas Vehicles Report estimates that there are more than 110,000 natural gas vehicles in the United States compared to approximately 13.8 million worldwide.

Natural Gas as an Alternative Fuel for Vehicles

We believe that natural gas is an attractive alternative to gasoline and diesel for vehicle fuel in the United States and Canada because it is cheaper and cleaner than gasoline or diesel. In addition, almost all natural gas consumed in the United States and Canada is produced from U.S. and Canadian sources. According to the EIA, in 2010 there were approximately 300 million gasoline gallon equivalents of natural gas consumed in the United States for vehicle use, which is more than double the amount consumed in 2000. The Clean Vehicle Education Foundation estimates that there are over 1,100 natural gas fueling stations in the United States.

Natural gas vehicles use internal combustion engines similar to those used in gasoline or diesel powered vehicles. A natural gas vehicle uses airtight storage cylinders to hold CNG or LNG, specially designed fuel lines to deliver natural gas to the engine, and an engine tuned to run on natural gas. Natural gas fuels have higher octane content than gasoline or diesel, and the acceleration and other performance characteristics of natural gas vehicles are similar to those of gasoline or diesel powered vehicles of the same weight and engine class. Natural gas vehicles, whether they run on CNG or LNG, are refueled using a hose and nozzle that makes an airtight seal with the vehicle's gas tank. For heavy duty vehicles, spark ignited natural gas vehicles operate more quietly than diesel powered vehicles. Several municipalities are encouraging the use of natural gas trucks because of their quieter operation in urban settings.

Almost any make or model passenger car, truck, bus or other vehicle is capable of being manufactured or modified to run on natural gas. In other countries, numerous makes and models of vehicles are produced from the factory to run on natural gas. However, in North America, only a limited number of models of natural gas vehicles are available. Only Honda offers a factory built natural gas passenger vehicle for sale in North America, a version of its Civic 4-door Sedan called the GX. However, Chrysler's parent Fiat announced its plan in December 2010 to bring CNG vehicle products to the United States market as the company views natural gas to be suitable for the country given the fuel's abundance in North America. A limited number of other passenger vehicles, vans and light duty trucks are available through small volume manufacturers, such as our wholly owned subsidiary, BAF. These small volume manufacturers offer model vehicles made by major automobile manufacturers that they have modified to use natural gas and have been certified to meet federal and state emissions and safety standards. Several General Motors Company ("GM") and Ford Motor Company ("Ford") models are now certified, including the Ford Crown Victoria, Ford E Series vehicles, Ford F Series trucks, and GM vehicles that include pickups, vans, cargo vans, and trucks. We anticipate additional models will be certified in 2011. Modifications involve removing the gasoline fuel system and replacing it with a compressed natural gas fuel storage system and an associated computer controlled fuel management system for the engine.

Heavy duty natural gas vehicles are manufactured by traditional original equipment manufacturers. These manufacturers offer some of their standard model vehicles with natural gas engines and components, which they make or purchase from engine manufacturers. Cummins Westport Inc., a joint venture of Cummins Inc. and Westport Innovations Inc., Westport Innovations Inc. (on its own), and Navistar International Corporation manufacture natural gas engines for medium and heavy duty fleet applications, including transit buses, class 8 trucks, refuse trucks, delivery trucks and street sweepers.

In 2010, several engine manufacturers initiated new engine development programs that may eventually lead to a greater selection of natural gas engines for wider applications in the future.

Natural Gas Medium and Heavy Duty Vehicle Manufacturers

Medium and heavy duty natural gas vehicle manufacturers include:

Trucks: Altec, Autocar, American LaFrance, Crane Carrier Company, Freightliner, Kenworth, Peterbilt, and Volvo.

Shuttles and Buses: BAF (vans and shuttles), Thomas Built Buses (school buses), Blue Bird (school buses), Complete Coach Works (shuttles), El Dorado National (shuttles and transit buses), New Flyer (transit buses), North American Bus Industries, Inc. (transit buses), and Orion Bus Industries (transit buses).

Specialty: Allianz Madvac (street sweepers and specialty sweepers and vacuums), Capacity (yard hostler trucks for port drayage), Elgin (street sweepers), and Tymco (street sweepers).

Benefits of Natural Gas Fuel

Less Expensive. Based on EIA data, since 2004, CNG and LNG have been significantly less expensive than gasoline and diesel. For example, in 2010, the average retail CNG price we charged in California, our most significant market, was $0.58 less per gasoline gallon equivalent than the average

California regular unleaded gasoline price of $3.09 per gallon. For fleet customers, (i.e. high volume users), the savings per gasoline gallon equivalent can be greater. In addition, CNG and LNG are also currently cheaper than the three other most widely available alternative fuels, propane, ethanol blends and biodiesel, as reported by the DOE on an energy equivalent basis.

Tax incentives have historically enhanced the cost-effectiveness of CNG and LNG. The U.S. federal excise tax credit of $0.50 per gasoline gallon equivalent of CNG and $0.50 per liquid gallon of LNG sold for vehicle use available to sellers of the fuel was made retroactive to January 1, 2010 during the year, and extended through December 31, 2011. However, a U.S. federal income tax credit that offset 50% to 80% of the incremental cost of purchasing a new or converted natural gas vehicles expired December 31, 2010. We believe that legislation may be re-introduced in Congress during 2011 that would extend the fuel tax credit beyond 2011 or reinstate, extend and increase the natural gas vehicle credit in addition to other incentives for the purchase of natural gas vehicles. Members of Congress have indicated support for such legislation; however, the legislative process is inherently uncertain and we do not know if or when any of the legislation providing for reinstatement, extension or new incentives for natural gas fuel or vehicles will be passed.

We believe that diesel fuel will become more expensive over the next several years due to a combination of rising crude oil prices and refiners being required to meet additional federal standards regarding the content of sulfur in diesel. In some areas of the country, refineries may be required to purchase carbon credits from low carbon fuel providers, such as we are, to comply with regional Low Carbon Fuel Standards taking effect in California, Oregon, and potentially eleven other states located in the Mid-Atlantic and Northeastern parts of the country. Additionally, all diesel engine manufacturers will have to comply with the more stringent EPA and NHTSA standards this year that will require improved fuel economy targets, which could increase the cost of diesel engines.

The chart below shows our average pump prices in California for CNG relative to California retail regular gasoline and diesel prices on a gasoline gallon equivalent basis for the periods indicated. CNG and LNG powered vehicles produce roughly the same miles per gallon as compared to gasoline or diesel powered vehicles.

Average California Retail Prices

(per gasoline gallon equivalent)(1)

	Year Ended December 31,		
	2008	2009	2010
California retail gasoline(2)	$ 3.51	$ 2.68	$ 3.09
California retail diesel(2)(3)	3.53	2.34	2.84
California CNG—Clean Energy	2.67	2.14	2.51
CNG discount to gasoline	(0.84)	(0.54)	(0.58)
CNG discount to diesel	$(0.86)	$(0.20)	$(0.33)

(1) Industry analysts typically use the gasoline gallon equivalent method in an effort to provide a normalized or "apples to apples" comparison of the relative cost of CNG compared to gasoline and diesel. Using this method, the cost of CNG is presented based on the amount of CNG required to generate the same amount of energy, measured in British Thermal Units, or BTUs, as a gallon of gasoline.

(2) Retail gasoline and diesel prices from the EIA.

(3) Converted to gasoline gallon equivalents assuming 125,000 BTU and 139,000 BTU per gallon of gasoline and diesel, respectively.

The following chart shows the estimated annual fuel cost savings that may be achieved by the natural gas vehicle.

Representative Annual per Vehicle Fuel Cost Savings
by Fleet Market for California
Based on Average Fuel Prices During 2010

Market	Fuel	Estimated annual fuel usage (gallons)(1)(2)	Cost of fuel CNG or LNG vs. gasoline or diesel (gallons)(1)(3)		Estimated annual fuel cost savings
Taxi	CNG or Gasoline	5,000	$2.51(4)	vs. $3.09(4)	$ 2,900
Shuttle van	CNG or Gasoline	7,500	$2.51(4)	vs. $3.09(4)	$ 4,350
Municipal transit bus (CNG) .	CNG or Diesel	16,680	$1.54(5)	vs. $2.26(6)	$12,010
Refuse truck (CNG)	CNG or Diesel	11,120	$1.57(5)(7)	vs. $2.84(6)	$14,122
Municipal transit Bus (LNG) .	LNG or Diesel	16,680	$1.72(5)	vs. $2.26(6)	$ 9,007
Refuse truck (LNG)	LNG or Diesel	11,120	$1.75(5)(7)	vs. $2.84(6)	$12,121

(1) CNG and LNG volumes are stated on a gasoline gallon equivalent basis. Industry analysts typically use the gasoline gallon equivalent method in an effort to provide a normalized or "apples to apples" comparison of the relative cost of CNG and LNG compared to gasoline and diesel. Using this method, the cost of each fuel is presented based on the same amount of energy, measured in BTUs, as a gallon of gasoline.

(2) Average fleet vehicle usage estimated by us based on experience with our customers. Estimated usage for a taxi is based on a "single-shift" driving program.

(3) Fuel prices for municipal transit buses are lower compared to refuse trucks because fuel for municipal buses is not subject to fuel excise taxes.

(4) CNG retail pricing is based on average Clean Energy retail station pricing in California during 2010. Gasoline retail pricing is based on California average retail gasoline prices during 2010 as reported by EIA.

(5) CNG and LNG prices based on average prices paid by representative Clean Energy California fleet customers in 2010.

(6) Diesel price based on EIA reported average diesel price in California in 2010.

(7) Excludes California Board of Equalization taxes of $0.0875 per gasoline gallon equivalent on CNG vehicles and $0.06 per gallon on LNG vehicles, as these customers typically buy an annual permit of $168.00 per truck over 12,000 gross vehicle weight ("GVW") that allows them to opt out of this tax.

Cleaner. Use of CNG and LNG as a vehicle fuel creates less pollution than use of gasoline or diesel, based on data from South Coast Air Quality Management District studies. On-road mobile source emissions reductions are becoming increasingly important because many urban areas have failed to meet federal air quality standards. This failure has led to the need for more stringent governmental air pollution control regulations.

The table below shows an example of emissions reductions for the 2011 Honda Civic GX versus its gasoline powered counterpart. Comparisons are based on information submitted to the EPA by the manufacturer.

		Test & Certified maximum grams per mile			
Model	**Fuel**	**NOx Test Data**	**NOx Cert Level**	**NMOG Test Data**	**NMOG Cert Level**
2011 Honda Civic	CNG	0.002	0.010	0.002	0.002
2011 Honda Civic	Gasoline	0.014	0.040	0.030	0.043
Emission Reduction		***86%***	***75%***	***93%***	***95%***

In 2007, new federal emissions requirements became effective for medium and heavy duty engines, and more stringent requirements went into effect in 2010. These requirements limit the levels of specified emissions from new vehicle engines manufactured in or after these years, and have resulted in cost increases for both acquiring and operating diesel vehicles. In order to comply with these standards, 2010 and later diesel engine models have employed significant new emissions control technologies such as advanced particulate matter (PM) traps, exhaust gas recirculation systems, and selective catalytic reduction (SCR) strategies that require urea, all of which have resulted in increases to the cost of medium and heavy duty diesel vehicles. According to industry sources, the purchase price of a 2010 heavy duty diesel vehicle that meets the 2010 diesel emission standards increased by more than $10,000 per vehicle. The 2010 and newer diesel vehicles require the use of ultra-low sulfur diesel fuel in order to meet the standards, which we believe increases the cost of operating and maintaining medium and heavy duty diesel vehicles. Manufacturers claim that the addition of SCR technology, while being more expensive, could provide a slight improvement in engine efficiency. We expect these additional controls, along with urea, will generally increase the cost to own and operate diesel vehicles.

South Coast Air Quality Management District completed a study that compared emissions levels of natural gas and other alternative fuels to those of existing pre-2007 diesel engines. The results, shown in the chart below, demonstrate that natural gas vehicle fuels produce significantly lower emissions than biodiesel, ethanol blends and diesel technologies. The figures show the percentage reduction in NOx and PM compared to emissions from standard diesel engines. Little or no data on the performance of 2011 diesel engines is currently available for analysis.

Proven Commercially Alternative Fuels and Diesel Technologies

Technology	**NOx reduction**	**PM reduction**
Natural gas	≥30 - 50%	>85%
Diesel emulsions	10 - 15%	50 - 65%
Biodiesel (B20)	−5% - 0%	15 - 20%
Ethanol blends	2 - 6%	35 - 40%
Oxidation catalysts for diesel engines	0 - 3%	~20%
NOx/PM traps for diesel engines	0%	>85%
Low-sulfur diesel	Minimal	~20%

Source: South Coast Air Quality Management District

In September 2006, California Governor Arnold Schwarzenegger signed AB 32—the Global Warming Solutions Act of 2006—into law, which calls for a cap on greenhouse-gas emissions throughout California and a statewide reduction to 1990 levels by the year 2020, and an additional 80% reduction below 1990 levels by 2050. To achieve the state's greenhouse gas reductions for mobile sources, the California Air Resources Board in 2007 identified an "early action item" under AB 32 called the Low Carbon Fuel Standard that requires a 10% carbon reduction in gasoline and diesel fuels sold in the State of California by 2020 and therefore encourages other low carbon transportation fuels to enter the marketplace by allowing them to generate carbon credits that can be sold to noncompliant regulated parties starting January 1, 2011. Under this regulation, CNG, LNG and biomethane are identified as "compliant fuels" through 2020 as their carbon benefits have been verified to far exceed the regulation's 2020 goal of a 10% reduction. Further, the California Air Resources Board adopted a cap and trade program under AB 32 in December 2010 that will allow fuel providers to sell carbon credits generated under the Low Carbon Fuel Standard into the larger cap and trade program as early as 2013. This will allow fuel providers that generate credits to sell such credits beyond the Low Carbon Fuel Standard's regulated parties to the broader California cap and trade program, and potentially to other cap and trade markets under development such as the Western Climate Initiative.

The Western Climate Initiative is made up of seven western U.S. states (Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington) and four Canadian provinces (British Columbia, Manitoba, Ontario and Quebec) with intent of forming a regional cap and trade market. Eleven Northeast and Mid-Atlantic U.S. states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Pennsylvania and Vermont) have already formed the Regional Greenhouse Gas Initiative to help combat climate change. Both efforts aim to implement market-based programs to reduce global warming pollution from stationary and mobile sources. We believe that the adoption of regional cap and trade programs can lead other states to adopt their own Low Carbon Fuel Standards. For example, each governor representing the eleven states that make up the Regional Greenhouse Gas Initiative have signed a memorandum of understanding to develop their own Low Carbon Fuel Standard by year 2012 and Oregon is expected to implement its Low Carbon Fuel Standard on January 1, 2012. Additional regulations that could stimulate growth in our market include AB 118, which Governor Schwarzenegger signed into law in 2007, and that provides approximately $210 million per year for seven years to fund alternative fuel programs, including CNG, LNG and biogas, aimed at reducing greenhouse-gas emissions and improving air quality; and AB 1007, the State Alternative Fuels Plan (that was adopted by the California Energy Commission in 2007) which establishes a goal of displacing 26% of California's petroleum fuel use by 2022 with alternative fuels, including natural gas.

Transportation is responsible for approximately 29% of total U.S. greenhouse-gas emission, and over 5% of global greenhouse gas emissions. As set forth in a report by TIAX, LLC, on a full life-cycle ("well to wheels") analysis, natural gas as a vehicle fuel results in greenhouse-gas reductions of up to 30% for light duty vehicles and up to 23% for medium and heavy duty vehicles.

Biomethane use is also a means to reduce greenhouse gas emissions. Biomethane is renewable natural gas produced from waste streams such as landfills, animal waste "lagoons" and sewage processing plants. A recent full lifecycle analysis performed by the California Air Resources Board estimates that use of biomethane generated from landfills as a vehicle fuel can reduce greenhouse-gas emissions up to 88% as compared to gasoline. According to The American Biogas Alliance, biomethane can be liquefied or injected into a pipeline and is compatible with existing natural gas fueling infrastructure. Further, in February 2010, the U.S. Environmental Protection Agency finalized the Renewable Fuel Standard Phase 2 that allows for the generation of tradeable "RINS" that can be generated by production and use in the transportation sector and can be sold to fuel providers that are not compliant under the rule.

Safety. As reported by NGV America, CNG and LNG are safer than gasoline and diesel because they dissipate into the air when spilled or in the event of a vehicle accident. When released, CNG and LNG are also less combustible than gasoline or diesel because they ignite only at relatively higher temperatures. The fuel tanks and systems used in natural gas vehicles are subjected to a number of federally required safety tests, such as fire, cycling tests, environmental hazard tests, burst pressures, and crash testing, according to the U.S. Department of Transportation National Highway Traffic Safety

Administration. CNG and LNG are generally stored in above ground tanks and therefore are not likely to contaminate soil or groundwater.

Domestic supply. In 2010, the United States consumed 19.1 million barrels of crude oil per day, of which 42% was supplied from the United States and Canada and 58% was imported from other countries, according to the EIA. By comparison, the EIA estimates that 98% of the natural gas consumed in the United States in 2010 was supplied from the United States and Canada, making it less vulnerable to foreign supply disruption. In addition, the EIA estimates that less than 1% of the estimated 24.1 trillion cubic feet of natural gas consumed in the United States in 2010 was used for vehicle fuel. We believe that a significant increase in use of natural gas as a vehicle fuel would not materially impact the overall demand for natural gas supplies.

Analysts believe that there is a significant worldwide supply of natural gas relative to crude oil. According to the 2010 BP Statistical Review of World Energy, on a global basis, the ratio of proven natural gas reserves to 2009 natural gas production was 37% greater than the ratio of proven crude oil reserves to 2009 crude oil production. This analysis suggests significantly greater long term availability of natural gas than crude oil based on current consumption.

On June 18, 2009, the Potential Gas Committee ("PGC") released its report on the natural gas resource base in the U.S. The report states that the United States possesses a total resource base of 1,836 trillion cubic feet (Tcf). This is the highest resource evaluation in the PGC's 44 year history. Another study published by Navigant Consulting in 2008, and further updated in 2009, defined the recoverable natural gas resources at 2,247 Tcf, or 118 years at current consumption levels.

Business Strategy

Our goals are to capitalize on the anticipated growth in the consumption of natural gas as a vehicle fuel and to enhance our leadership position as that market expands. To achieve these goals, we are pursuing the following strategies:

Focus on high-volume fleet customers. We will continue to target fleet customers such as public transit, refuse haulers and regional trucking companies, as well as vehicle fleets that serve airports and seaports. We believe these are ideal customers because they are high-volume users of vehicle fuel and can be served by a centralized fueling infrastructure. We have recently focused on seaports because they are among the biggest air polluters and many are under increasing regulatory pressure to reduce emissions. In November 2006, two of the nation's largest seaports, the Ports of Los Angeles and Long Beach (Ports), adopted the San Pedro Bay Clean Air Action Plan ("Plan"), which calls for the retrofit or replacement of trucks serving those ports with trucks that run on cleaner technology, such as LNG trucks. In November 2007, the Ports voted for a progressive ban of trucks that do not meet the 2007 emission standards from operating at the Ports. The ban began on October 1, 2008 and continues through January 1, 2012, when all trucks servicing the Ports must at least meet the EPA 2007 diesel emission standards. In December 2007, the Ports approved a cargo fee of $35 per loaded twenty-foot equivalent cargo container entering or leaving any terminal by truck to help fund the Plan, which they began collecting on February 18, 2009. LNG trucks are exempt from the cargo fees.

In December 2007, we opened the first fueling station in the port area to fuel LNG-powered trucks. In July 2009, we opened the second fueling station in the Port of Long Beach area to fuel LNG-powered trucks. In addition, we have selected other potential fueling station sites for development that would be capable of providing LNG fueling for the trucks servicing the Ports. We intend to model LNG truck deployment programs at other ports based on our experience in providing LNG fuel at the Ports of Los Angeles and Long Beach. In October 2010, we signed an agreement with Pilot Travel Centers LLC ("Pilot Flying J") to build, own and operate public access, CNG and LNG fueling facilities at agreed-upon Pilot Flying J truck travel centers nationwide and in Canada to support the growing demand for natural gas-fueled trucking.

Capitalize on the cost savings of natural gas. We will continue to capitalize on the cost advantage of natural gas as a vehicle fuel. We educate fleet operators on the advantages of natural gas fuels, which include the cost savings relative to gasoline and diesel and the emission reductions that are achieved by switching from gasoline and diesel to natural gas fuel. We also educate fleet operators about various tax incentives and grants, including tax incentives and grants that reduce the purchase price of natural gas vehicles, which we believe accelerates the adoption of natural gas vehicles.

Leverage first mover advantage. We plan to continue to capitalize on our initial presence in a number of growing markets for CNG and LNG, such as public transit, refuse hauling, seaports, and airports, where there is increasing regulatory pressure to reduce emissions and where natural gas vehicles are already used in fleets. We plan to expand our business with existing customers as they continue to replace diesel and gasoline powered vehicles with natural gas vehicles. We intend to use our knowledge and reputation in these markets to win business with new customers.

Optimize LNG supply advantage. The supply of LNG in the United States and Canada is limited. We believe that increasing our LNG supply will enable us to increase sales to existing customers and to secure new customers. We use our LNG supply relationships and strategically located LNG production capacity to give us a competitive advantage. In addition to our own LNG liquefaction plants in Texas and California, we have relationships with five LNG supply plants in the western United States. Our LNG liquefaction plant in California will enhance our ability to serve California, Arizona and other western U.S. markets and will help us to optimize the allocation of LNG supply we sell to our customers. Also, in October 2007, we entered into an LNG sales agreement with Desert Gas Services (formerly known as Spectrum Energy Services), LLC ("DGS"), whereby we will purchase, on a take-or-pay basis over a term of 10 years, 16 million gallons of LNG per year from a plant constructed by DGS in Ehrenberg, Arizona, which is near the California border. The plant started commercial operations in March, 2010. In the future, we may also acquire natural gas reserves or rights to natural gas production to supply our LNG plants.

Develop renewable biomethane production capabilities. Through our majority-owned subsidiary, DCE, we are producing from a landfill renewable pipeline quality biomethane, which can be used to generate renewable electricity and as a renewable low carbon fuel. According to the California Air Resources Board, the use of biomethane as CNG vehicle fuel can reduce greenhouse gas emissions by up to 88% as compared to gasoline. By developing biomethane production capabilities, we are able to offer customers renewable, low-carbon fuel options. In November 2010, we signed a renewable biomethane recovery agreement with Republic Services, Inc., a leading solid waste operator, to process and sell renewable natural gas recovered from Republic's Saulk Trail Hills landfill site in Canton, Michigan.

Integration Strategy. With our acquisition of IMW, we acquired the leading global supplier of CNG equipment for vehicle fueling. IMW's products and services include compressors, dispensers, storage systems, CNG parts and technical services. We believe IMW is the leading manufacturer of CNG compressors because it designed its compressors specifically for the requirements of natural gas fueling operations. IMW's non-lubricated compressor technology prevents costly and troublesome oil accumulation in heat exchangers, storage vessels, and vehicle systems. This ensures lower operating costs and increased reliability. IMW also manufactures a smaller compressor unit that can be used in a smaller CNG station application. The smaller application can be used for smaller fleets, to add a node to a network, or for the initial fueling needs of a larger fleet until their fueling needs require a larger station. IMW has manufacturing centers in Canada and China, and service centers in Canada, China, Colombia, Bangladesh and the U.S.

Our acquisition of IMW was driven by three desires. First, we wanted to make sure we could satisfy our internal compressor needs, since compressors are the most important piece of equipment for a CNG station. As the adoption of natural gas vehicles has increased, our CNG station construction backlog has increased and our compressor requirements have increased. We believe our compressor needs will continue to grow in the future. By acquiring IMW, we are assured of having compressors readily available to deploy at our stations. The second driver for acquiring IMW was our desire to be able to provide certain customers with a "factory direct" offering. Since some customers do not want our full suite of services and simply want a station that they can own and operate, we can now offer them a high quality and low cost solution. The third driver of the IMW acquisition was our desire to participate in the global growth of natural gas vehicle fueling. In 2010, 32.6% of IMW's sales came from outside of North America, and IMW has a very strong reputation in the global market. As the global market continues to grow, we believe IMW will benefit and participate in such growth.

In October 2010, we signed an agreement with Pilot Flying J to build, own and operate public access CNG and LNG fueling facilities at agreed-upon Pilot Flying J travel centers nationwide to support the growing demand for natural gas-fueled trucking in the United States. Pilot Flying J operates over 550 truck travel centers in 43 states and six Canadian provinces. By partnering with Pilot Flying J, which is the largest truck-fueling operator in the country, we will be in a good position to build LNG stations along interstate highway corridors between major transportation hubs. Also, by having LNG fueling islands within Pilot Flying J travel centers, truck operators can enjoy the conveniences they are accustomed to while fueling with LNG, which will help facilitate the transition away from diesel trucks.

We acquired Northstar in December 2010. Northstar provides LNG and LCNG station design, construction operations and maintenance services. Northstar has built over 65% of all LNG and LCNG stations in the United States and we have worked closely with Northstar for several years. Northstar is also a leader in LNG and LCNG fueling system technologies, including the manufacture of one of only two weights-and-measures certified LNG dispensers. Northstar will be a key piece to help with the anticipated roll-out of LNG stations at Pilot Flying J travel centers.

In the future, we anticipate we will continue to pursue acquisitions and partnerships as we become aware of opportunities where we believe we can increase our competitive advantages or enhance our market position.

Operations

Our revenue principally comes from delivering (by selling and providing station operating and maintenance services) CNG and LNG fuel to our customers and selling converted natural gas vehicles. We also generate revenues by designing and constructing fueling stations and selling or leasing those stations to our customers, selling biomethane gas through our interest in DCE, and selling natural gas vehicle fuel compression equipment. Substantially all of our operating and maintenance revenues are generated from CNG stations, as owners of LNG stations tend to operate and maintain their own stations. Substantially all of our station sale and leasing revenues have been generated from CNG stations. In 2006, we began providing vehicle finance services to our customers. In August 2008, we acquired 70% of DCE and began processing and selling biomethane gas. On October 1, 2009, we acquired BAF and began providing natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles. On September 7, 2010, we acquired IMW and began selling advanced, non-lubricated natural gas fueling compressor and related equipment and maintenance services. On December 15, 2010, we acquired Northstar, a leading provider of design, engineering, construction and maintenance services for LNG and LCNG fueling stations. Each of these activities are discussed below.

Natural gas for CNG stations. We obtain natural gas for CNG stations from local utilities or brokers under standard arrangements which provide that we purchase natural gas at a published rate or negotiated prices. The natural gas is delivered via pipelines owned by local utilities to fueling stations where it is cleaned, compressed, stored and dispensed into vehicles on site. In some cases, we receive special rates from local utilities because of our status as a supplier of CNG for transportation.

LNG production and purchase. We obtain LNG from our own plants as well as through relationships with five suppliers in the western United States. Combining these sources provides important flexibility and helps to create a reliable supply for our LNG customers. We own and operate LNG liquefaction plants near Houston, Texas and Boron, California, which we call the Pickens Plant and California LNG Plant, respectively. The Pickens Plant has the capacity to produce 35 million gallons of LNG per year and also includes tanker trailer loading facilities and a 1.0 million gallon storage tank that can hold up to 840,000 usable gallons. Additionally, the LNG liquefaction plant in California (which produced its first load of LNG in November 2008), is capable of producing 60 million gallons of LNG per year (with expansion potential to produce 90 million LNG gallons per year) and will enable us to supply our operations in California and Arizona more economically as our supply source will be closer to our customers' locations. This plant has tanker trailer loading facilities similar to the Pickens Plant and a 1.8 million gallon storage tank that can hold up to 1.5 million usable gallons.

As of December 31, 2010, we had outstanding purchase contracts with various third-party LNG suppliers in the western United States. For the year ended December 31, 2010, of the LNG we sold, we purchased 28% from these suppliers and the balance was produced at our Pickens Plant and California LNG Plant. Two of our LNG supply contracts contain take-or-pay provisions which require that we purchase specified minimum volumes of LNG at index-based prices or pay for the amounts that we do not purchase. If we need additional LNG and it is available from these suppliers, we generally may purchase it from them, typically at the market price for natural gas plus a liquefaction fee. To date, we have taken and sold the required amounts under our take-or-pay contracts.

We have a fleet of 58 tanker trailers that we use to transfer LNG from our third-party suppliers and production plants to individual fueling stations. We typically own the tanker trailers and we contract with third parties to provide tractors and drivers. Each LNG tanker trailer is capable of carrying 10,000 gallons of LNG. To optimize our distribution network, we use an automated tracking system that enables us to monitor the location of a tanker trailer at any time, as well as an automated fueling station tank-monitoring system that enables us to efficiently schedule the refilling of each station, which helps ensure that our customers have sufficient fuel to operate their fleets.

Operations and maintenance. Typically, we perform operations and maintenance services for CNG stations, which are either owned by us or our customers. Although we may from time to time own or operate and maintain LNG stations, LNG stations are most often owned and maintained by our customers and supplied by us. Most of the CNG and LNG stations that we maintain or supply are monitored from our centralized operations center, facilitating increased reliability and safety, as well as lower operating costs. This monitoring helps us to ensure the timely delivery of fuel and to respond rapidly to any technical difficulties that may arise. In addition, we have an automated billing system that enables us to track our customers' usage and bill them efficiently. As of December 31, 2010, we had an operations team of 92 employees, including 58 full-time employees dedicated to performing preventative maintenance and available to respond to service requests in 20 states and in Canada. In addition, since September 7, 2010, with the acquisition of IMW, we added 63 full-time employees dedicated to performing preventative maintenance on IMW's foreign installations and who are based in Bangladesh, Columbia and China.

Our station network. As of December 31, 2010, we owned, operated or supplied 224 fueling stations for our customers in Arizona, California, Colorado, District of Columbia, Florida, Georgia, Idaho, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Rhode Island, Texas, Virginia, Washington, Wyoming, and Canada. Of these 224 stations, we owned 138 of the stations, and our customers owned the other 86 stations. The breakdown of the services we perform for these stations is set forth below.

	As of December 31, 2010		
	CNG fueling stations	LNG fueling stations	Total stations
Operated, maintained and supplied by Clean Energy	111	8	119
Supplied by Clean Energy, operated and maintained by customer	—	28	28
Operated and maintained by Clean Energy, supplied by customer	66	11	77
Total	177	47	224

For the month of December 2010, 30 of the stations listed in the table above delivered in excess of 100,000 gasoline gallon equivalents, and 45 stations delivered in excess of 25,000 gasoline gallon equivalents (but less than 100,000 gasoline gallon equivalents). Of the 30 stations delivering greater than 100,000 gasoline gallon equivalents per month, 23 relate to transit customers, four relate to airport locations, two relate to public stations and one relates to a refuse customer. Of the 45 stations delivering greater than 25,000 gasoline gallon equivalents (but less than 100,000 gasoline gallon equivalents), 16 relate to refuse customers, nine relate to airport locations, nine relate to transit customers, eight relate to public stations and three relate to industrial customers. In general, stations delivering higher volumes are more cost effective and perform better financially due to operating efficiencies obtained by the spreading of a station's fixed costs over a larger revenue base. With respect to station performance by geographic region, stations located in busy metropolitan areas, particularly near airports, experience higher traffic and deliver higher volumes compared to stations located in areas that are less densely populated.

Station construction and engineering. Since 2008, we have built 105 natural gas fueling stations, either serving as general contractor or supervising qualified third-party contractors, for ourselves or our customers. We acquired the additional stations we own that we did not build through acquisition of assets or businesses. We use a combination of custom designed and off-the-shelf equipment to build fueling stations. Equipment for a CNG station typically consists of dryers, compressors, dispensers and storage tanks (which hold a relatively small buffer amount of fuel). Equipment for an LNG station typically consists of storage tanks that hold 10,000 to 25,000 gallons of LNG, plus related dispensing equipment.

A number of our CNG fueling stations have separate public access areas for retail customers, which have the look, feel and fill rates of a traditional gasoline fueling station. Our CNG dispensers are designed to fuel at five to six gasoline gallon equivalents per minute, which is comparable to a traditional gasoline fueling dispenser. Our LNG dispensers are designed to fuel at 40 diesel gallon equivalents per minute, similar to a diesel fueling dispenser. LNG dispensing requires special training and protective equipment because of the extreme low temperatures of LNG.

Biomethane. In August of 2008, we acquired 70% of the outstanding membership interests of DCE. DCE owns a facility that collects, processes and sells renewable, pipeline-quality biomethane at the McCommas Bluff landfill located in Dallas, Texas. During 2010, we generated approximately $11.3 million in revenues from sales of biomethane by DCE, which represents 100% of DCE's revenue, which is included on a consolidated basis in our financial statements. In November 2010, we entered into an agreement with Republic Services Group to develop a second biomethane project at their landfill in Canton, Michigan. The project is anticipated to commence operations in 2012.

Vehicle conversion. On October 1, 2009, we acquired BAF, a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles. During 2010, we generated approximately $42.3 million in revenue from BAF's operations.

Natural gas fueling compressors. On September 7, 2010, we acquired IMW, a company that manufactures and services advanced, non-lubricated natural gas fueling compressors and related equipment for the global natural gas fueling market. Since September 7, 2010, we generated approximately $17.8 million in revenues from IMW's operations.

Sales and Marketing

We have sales representatives in all of our major operating territories, including Los Angeles, San Francisco, San Diego, Phoenix region, Boston region, New York, Denver, Dallas, Atlanta, New Jersey, Seattle, New Mexico, Chicago, Florida, Virginia, Minnesota, Kentucky, Indiana, New Hampshire, Missouri, and Toronto. At December 31, 2010, we had 71 employees in sales and marketing, including five employees of BAF and ten employees of IMW. As our business grows and we enter new markets over the next several years, we intend to continue expanding our sales and marketing team, primarily by adding specialized sales experts to focus on fleet market opportunities in targeted metropolitan areas where we do not yet have a strong presence. We market primarily through our direct sales force, attendance at trade shows and participation in industry conferences and events. Our sales and marketing group works closely with federal, state and local government agencies to educate them on the value of natural gas as a vehicle fuel and to keep abreast of proposed and newly adopted regulations that affect the industry. Several of our U.S. sales offices are located in "nonattainment" areas, or near-non-attainment areas, under the Federal Clean Air Act, where government regulations are more likely to mandate vehicle pollution controls.

Since September 7, 2010, with the acquisition IMW's operations, we also have sales representatives in Bangladesh, Columbia and China.

Customer Vehicle Financing

We provide, or help our customers obtain, financing to acquire natural gas vehicles or convert their vehicles to operate on natural gas. In 2006, we began to loan to certain qualifying customers a portion of, and occasionally up to 100% of, the up-front capital needed to purchase natural gas vehicles or convert existing vehicles to use natural gas. To ensure the availability of vehicles for our customers, we may also purchase natural gas vehicles or components of natural gas vehicles in anticipation of customer requirements. We also use our in-house grant specialists to help secure government grants, tax rebates and related incentives for ourselves and our customers, which can be a challenging process. Our specialists have secured over $244.4 million in federal and state funding for ourselves and our customers since 1998. This expertise is important to our customers, as natural gas vehicle fleet operators have access to an increasing number of grants and other incentives to help defray a significant portion of the incremental costs of purchasing natural gas vehicles. As of December 31, 2010, we have not generated significant revenue from financing activities.

Customers and Key Markets

We have over 480 fleet customers operating approximately 21,270 vehicles, including approximately 5,530 transit buses, 1,770 taxis, 1,210 shuttles and 2,450 refuse trucks. We target customers in a variety of markets, such as airports, public transit, refuse, seaports, regional trucking, taxis and government fleets. From 2006 through 2010, approximately 53% of our revenues were derived from contracts with governmental entities such as municipal transit fleets. We do not depend on a single customer or a few customers, the loss of which would have a material adverse effect on us.

- *Airports*—Many U.S. airports face emissions challenges and are under regulatory directives and political pressure to reduce pollution, particularly as part of any expansion plans. Many of these airports already have adopted various strategies to address tailpipe emissions, including rental car and hotel shuttle consolidation. In order to reduce emissions levels further, many airports require or encourage service vehicle operators to switch their fleets to natural gas, including airport delivery fleets, door-to-door and parking shuttles and taxis. To assist in this effort, airports are contracting with service providers to design, build and operate natural gas fueling stations in strategic locations on their property. Airports we serve include Albuquerque, Atlanta Hartsfield-Jackson International, Austin-Bergstrom International, Baltimore-Washington International, Burbank, Dallas-Ft. Worth International, Love Field (Dallas), Long Beach, Denver International, LaGuardia (New York), Los Angeles International, Newark International, Oakland International, Palm Springs, Phoenix Sky Harbor International, San Francisco International, Santa Ana/John Wayne, San Diego International, SeaTac International (Seattle), and Tucson International. At these airports, our representative customers include taxi and van fleets, as well as parking and car rental shuttles.

- *Transit agencies*—According to the American Public Transportation Association, there are over 66,500 municipal transit buses operating in the United States. In many areas, increasingly stringent emissions standards have limited the fueling options available to public transit operators. For example, the South Coast Air Quality Management District in California has adopted an Air Toxic Control Plan designed to encourage the use of alternative fuel buses. Eligible buses include hybrid gasoline electric buses (which typically cost $165,000 more than a traditional gasoline or diesel powered bus), or natural gas powered buses (which typically cost $35,000 more than a traditional gasoline or diesel powered bus), a significant portion of which can be recaptured through tax credits. Some public transit authorities also allow hybrid diesel electric buses (which typically cost $200,000 more than a traditional gasoline or diesel powered bus). The cost comparison data in this paragraph are from Hybridcenter.org, a project of the Union of Concerned Scientists. Transit agencies have been early adopters of natural gas vehicles, with almost 30% of all buses in the United States operating on LNG, CNG or CNG blends, according to the American Public Transportation Agency 2010 Public Transportation Factbook. Our representative public transit customers include Dallas Area Rapid Transit, Santa Monica Big Blue Bus, Los Angeles Metropolitan Transit Authority, Boston Metropolitan Transit Development Agency, Phoenix Transit, Tempe Transit, Foothill Transit (California), Santa Cruz Metropolitan, Orange County Transit Authority, Regional Transit Commission of Nevada and Regional Transit Authority (Ohio).

- *Refuse haulers*—According to INFORM, there are nearly 200,000 refuse trucks in the United States, consuming approximately two billion gallons of fuel per year, that collect and haul refuse and recyclables from collection points to landfills and recycling facilities. Many refuse haulers are facing pressure from the municipalities they serve to reduce emissions. We estimate there are approximately 2,700 natural gas powered refuse hauling vehicles operating in the United States on CNG and LNG. Our representative refuse hauler customers include national accounts such as Waste Management, Republic Services and Waste Connections, as well as private waste haulers in eleven different states such as CleanScapes (Seattle), Choice Waste (FL), Recology (Formerly Norcal Waste), South San Francisco Scavenger, Burrtec (CA), Central Jersey Waste and Garofalo V & Sons (NY) among others. We also provide vehicle fueling services to municipal refuse fleets including fleets in Los Angeles, Fresno, Sacramento, Burbank, Dallas, San Antonio, and on Long Island, New York among other locations.

- *Seaports*—Seaports are typically large polluters because of emissions from cargo ships, trains, yard hostlers and trucks. Many seaports must reduce emissions levels in connection with any expansion efforts. A practical solution for reducing port emissions is to adopt policies that require alternative fuel vehicles in the seaport that have lower emissions than gasoline or diesel, such as natural gas. Such policies include requiring conversion to alternative fueling systems for regional trucking fleets that transport containers from the seaport to local distribution centers, as well as the yard hostlers that move containers around the shipyard. In November 2006, two of the nation's largest seaports, the Ports of Los Angeles and Long Beach (the "Ports"), adopted the San Pedro Clean Air Action Plan, which calls for the retrofit or replacement of trucks serving those ports so that they run on cleaner technology, such as LNG. In November 2007, the Ports introduced a progressive ban, beginning October 1, 2008, that will remove by 2012 all diesel trucks that do not meet 2007 emission standards. In December 2007, the Ports approved a $35 per twenty-foot container unit cargo fee that the Ports began collecting February 18, 2009. LNG trucks are exempt from the cargo fees.

In December 2007, we opened the first fueling station in the port area to fuel these LNG-powered trucks, and in July 2009 we opened a second port LNG fueling station at the Port of Long Beach. In addition, we have contracted to develop several other station sites to provide LNG fuel to the trucks servicing the Ports and operating in Southern California regional trucking.

- *Regional trucking*—According to the EPA, the average tractor-trailer uses over 11,500 gallons of fuel per year. Most of these trucks run on diesel fuel, which is becoming less desirable as emissions standards become increasingly more stringent. Diesel trucks must now meet EPA's 2010 emission standard using advanced emission control systems that add weight, cost, and complexity to the truck. Dedicated natural gas trucks can meet EPA's 2010 emission standards with simpler and less costly emission controls. For regional trucking, LNG is a more cost-effective fuel alternative that enables trucking companies to meet the evolving emissions standards. Our representative regional trucking customers include the Houston distribution centers of Sysco Food Services, a wholesale distributor of food products, United Parcel Service, the Houston distribution center of H.E. Butt Grocery Company, Trimac USA of Houston, and Pepsi Bottling Group.

- *Taxis*—According to the Taxi, Limousine, and Paratransit Association, there were approximately 6,300 companies operating 171,000 taxicabs in the United States in 2010. We believe that less than 2% of these vehicles were natural gas vehicles. Because taxi fleets travel many miles and can refuel at a central location, we believe they are excellent candidates to use CNG. Natural gas vehicles provide taxi fleets a convenient way to reduce operating costs and provide a clean environment for their drivers and customers. We serve approximately 1,770 taxis in Southern California, the San Francisco Bay Area, Dallas, Houston, Las Vegas, New York City, Phoenix, Tucson and Seattle. However, we have seen a significant interest in new policy initiatives at major airports across the country this past year, including Philadelphia, Cincinnati, and Newark Airports.

- *Government fleets*—According to the Federal Highway Administration, or FHA, in 2009, there were over 4.6 million government fleet vehicles in operation in the United States, including those operated by federal, state and municipal entities. In California and Texas, for example, according to the FHA, there were over 637,000 and 494,000 government vehicles, respectively. As government regulations on pollution continue to become more stringent, government agencies are evaluating ways to make their fleets cleaner and run more economically. Under the federal Energy Policy Act of 1992, 75% of new light-duty vehicles purchased by federal fleet operators are required to run on alternative fuels. Our representative government fleet customers include the California Department of Transportation (Los Angeles and Orange County), State of New York, City of Denver, City and County of Los Angeles, City of San Antonio, Town of Smithtown, City and County of San Francisco, City and County of Dallas and City of Phoenix.

Tax Incentives

Historically, U.S. federal and state government tax incentives and grant programs have been available to help fleet operators reduce the cost of acquiring and operating a natural gas vehicle fleet. Incentives were typically available to offset the cost of acquiring natural gas vehicles or converting vehicles to use natural gas, constructing natural gas fueling stations and selling CNG or LNG. The vehicle and fuel tax rebates and credits are key incentives designed to enhance the cost-effectiveness of CNG and LNG as vehicle fuels throughout the United States and are described below.

Fueling station credits. The Middle Class Tax Relief Act of 2010 (H.R. 4853) extends for one year the tax credit for natural gas fueling infrastructure. The extension is for 30% of the cost of qualified equipment up to a maximum of $30,000 and $1,000 for non-business property (i.e., home refueling).

Fuel credit. The H.R. 4853 extended until December 31, 2011 the $0.50 fuel credit for CNG and LNG when used as a transportation fuel. The bill also reinstated the credit retroactive to January 1, 2010. The $0.50 tax credit for CNG and LNG had expired at the end of 2009.

Vehicle credits. The federal income tax credit for natural gas vehicles expired on January 1, 2011.

Grant programs

We apply for and help our customers apply for grant programs available for fleets in several of the states in which we operate including California, New York, and Texas. These programs provide funding for natural gas vehicle purchases, station construction and natural gas fueling infrastructure and include the following:

Mobile Source Air Pollution Reduction Review Committee—The Mobile Source Air Pollution Reduction Review Committee, or MSRC, is a Southern California program that funds projects that reduce air pollution from motor vehicles within the South Coast Air Quality Management District in Southern California. The South Coast Air Quality Management District is a geographic region defined in state regulations to include all of Los Angeles and Orange Counties, and portions of Riverside and San Bernardino counties. The MSRC derives funding from a portion of the California Department of Motor Vehicles $4 per vehicle surcharge on an estimated 12.5 million vehicles operating in the South Coast District. For 2011, the surcharge is anticipated to result in approximately $22.7 million in funding and support for a variety of clean air programs, including grants to purchase natural gas vehicles and fueling station infrastructure. The MSRC has a yearly work program designed to fund projects that reduce air pollution from motor vehicles.

California Carl Moyer Program—The Carl Moyer Memorial Air Quality Standards Attainment Program, or Carl Moyer Program, was initiated in California in 1998 to reduce emissions from heavy duty, diesel-powered vehicles and other mobile sources. The Carl Moyer Program provides matching grants to private companies and public agencies in California to fund efforts to clean up emissions from their heavy duty engines through retrofitting, repowering or replacing them with newer and cleaner versions. Based on actual receipts from the prior fiscal year, the California Air Resources Board "CARB" anticipates $58.7 million in funding for the twelve months constituting their fiscal year 2010/2011. CARB allocated $25.8 million to the South Coast Air Quality Management District for the implementation of its Carl Moyer Program. Qualifying projects included those that reduce emissions from heavy duty on and off-road equipment, such as trucks over 14,000 pounds gross vehicle weight and off-road equipment such as construction equipment and airport ground support equipment.

Texas Emissions Reduction Plan—The Texas Emissions Reduction Plan is a comprehensive set of clean air incentive programs, including vehicle programs, designed to improve air quality in Texas. The Texas Commission on Environmental Quality administers grants under these programs. The grants are used to help reduce air pollution in Texas ozone "nonattainment" areas and in certain other near-non-attainment areas in the state and are often targeted towards reducing emissions from diesel equipment. In 2010, $154 million was made available for programs generally, a portion of which will partially fund the purchase or conversion of vehicles. As of March 10, 2011, the funding allocations for the current fiscal year have not been released although we anticipate a similar funding level.

U.S. Department of Energy Petroleum Reduction Technologies Projects for the Transportation Sector— This DOE program is administered through the DOE Clean Cities affiliates throughout the country. Approximately $15.5 million is available in 2011 for alternative fuel vehicle deployment and infrastructure projects. We anticipate pursuing funding opportunities with our customers to assist with the purchase of vehicles and construction of fueling infrastructure.

U.S. Environmental Protection Agency ("EPA") National Clean Diesel Funding Assistance Program— This national program provides funding to reduce emissions from existing diesel engines through a variety of strategies, including the use of alternative fuels. Anticipated funding for fiscal year 2011 is $50 million in total program dollars. A portion of this funding goes to individual states to support transportation air quality programs at that level. We expect to participate in regional funding programs which are administered through the EPA's seven regional offices.

Competition

The market for vehicular fuels is highly competitive. The biggest competition for CNG, LNG and other alternative fuels is gasoline and diesel, the production, distribution and sale of which are dominated by large integrated oil companies. The vast majority of vehicles in the United States and Canada are powered by gasoline or diesel.

Within the United States, we believe our largest competitors for CNG sales are: Trillium USA/Pinnacle CNG, a privately held provider of CNG fuel infrastructure and fueling services, which we believe focuses primarily on transit fleets in California, Arizona and New York and Pacific Gas and Electric, which operates public access CNG stations in Northern California. Within the U.S. LNG market, we believe our largest competitors are Applied LNG Technology and Prometheus Energy, each of which distributes LNG in the western United States.

We own, operate or supply 224 CNG and LNG fueling stations. We operate 177 CNG fueling stations, which we estimate is approximately four times the number of CNG fueling stations as our next largest competitor. We believe we are the only company in the United States or Canada that provides both CNG and LNG on a significant scale, and we operate in more states and provinces than any of our competitors.

Potential entrants to the market for natural gas vehicle fuels include the large integrated oil companies, other retail gasoline marketers, industrial gas companies and natural gas utility companies. The integrated oil companies produce and sell crude oil and natural gas, and they refine crude oil into gasoline and diesel. They and other retail gasoline marketers own and franchise retail stations that sell gasoline and diesel fuel. Integrated oil companies and other established fueling companies sell CNG at a number of their vehicle fueling stations that sell gasoline and diesel in international markets. Industrial gas companies produce and sell other gases and liquid fuels (such as helium, hydrogen, oxygen, etc) to industrial customers. Natural gas utility companies own and operate the local pipeline infrastructure that supplies natural gas to retail, commercial and industrial customers and some utilities also sell CNG fuel at public access stations.

It is possible that any of these competitors, and other competitors who may enter the market in the future, may create product and service offerings that compete with ours. Many of these companies have far greater financial and other resources and name recognition than we have. Entry by these companies into the market for natural gas vehicle fuels may reduce our profit margins, limit our customer base and restrict our expansion opportunities.

Other alternative fuels compete with natural gas in the retail market and may compete in the fleet market in the future. We believe there is room for all providers of alternative fuels in the vehicle fuels market. Suppliers of ethanol, biodiesel and hydrogen, as well as providers of hybrid and electric vehicles, may compete with us for fleet customers in our target markets. Many of these companies benefit, as we do, from U.S. state and federal government incentives that allow them to provide fuel more inexpensively than gasoline or diesel.

With our acquisition of IMW on September 7, 2010, we began selling CNG fueling equipment outside of North America. The market for CNG fueling equipment is highly competitive with several competitors selling in multiple countries. We believe our largest international competitors for CNG fueling equipment are Aspro and GNC Galileo (based in Argentina), SAFE (based in Italy), ANGI Energy Systems, Inc. (based in Wisconsin), and Atlas Copco (who has numerous international locations). Numerous other equipment or compressor manufacturing companies could also enter the market in the future.

Background on Clean Air Regulation

The Federal Clean Air Act provides a comprehensive framework for air quality regulation in the United States. Many of the federal, state and local air pollution control programs regulating vehicles and stationary sources have their basis in Title I or Title II of the Federal Clean Air Act.

Title I of the Federal Clean Air Act charges the EPA with establishing uniform National Ambient Air Quality Standards for criteria air pollutants anticipated to endanger public health and welfare. States in turn have the primary responsibility under the Federal Clean Air Act for achieving these standards. If any area within a state fails to meet these standards for a criteria air pollutant, the state must develop an implementation plan and local agencies must develop air quality management plans for achieving these standards. Many state programs regulating stationary source emissions, vehicle pollution or mobile sources of pollution are developed as part of a state implementation plan. For mobile sources, two criteria pollutants in particular are of concern: ozone and particulate matter. Many of the nation's metropolitan areas are in "nonattainment" status for one or both of these criteria air pollutants. As components of state implementation plans, individual states have also adopted diesel fuel standards intended to reduce NOx and particulate matter emissions. Texas and California have both adopted low-NOx diesel programs. Additionally, many state implementation plans and some quality management plans include vehicle fleet requirements specifying the use of low emission or alternative fuels in government vehicles. Finally, the U.S. Environmental Protection Agency under the Obama Administration has signaled that it wishes to strengthen tropospheric ozone standards (i.e. smog) to the levels recommended originally under the Bush Administration. Such a move would potentially increase the number of nonattainment areas throughout the country.

Title II of the Federal Clean Air Act authorizes the EPA to establish emission standards for vehicles and engines. Diesel fueled heavy duty trucks and buses have recently accounted for substantial portions of NOx and particulate matter emissions from mobile sources, and diesel emissions have received significant attention from environmental groups and state agencies. In 2001, the EPA finalized its Heavy Duty Highway Rule, also known as the 2007 Highway Rule. The 2007 Highway Rule seeks to limit emissions from diesel fueled trucks and buses on two fronts: new tailpipe standards requiring significantly reduced NOx and particulate matter emissions for new heavy duty diesel engines, and new standards requiring refiners to produce low sulfur diesel fuels that will enable more extensive use of advanced pollution control technologies on diesel engines.

The 2007 Highway Rule's tailpipe standards, which will apply to new diesel engines, were effective in 2007 and 2010. Specifically, new particulate matter standards took effect in the model year 2007 and new NOx standards were phased in between 2007 and 2010. The rule's fuel standards call for a shift by U.S. refiners and importers from low sulfur diesel, with a sulfur content of 500 parts per million (ppm), to ultra low sulfur diesel, with a sulfur content of 15 ppm. The rule, which will effect a transition to ultra low sulfur diesel, required refiners to begin producing ultra low sulfur diesel fuels on June 1, 2006.

Although the majority of state air pollution control regulations are components of state implementation plans developed pursuant to Title I of the Federal Clean Air Act, states are not precluded from developing their own air pollution control programs under state law. For example, the California Air Resources Board and the South Coast Air Quality Management District have promulgated a series of airborne toxic control measures under California state law, several of which are directed toward reducing emissions from diesel fueled engines.

Although the federal government has not adopted any laws that comprehensively regulate greenhouse gas emissions, the EPA is developing regulations that would regulate these pollutants under the Clean Air Act. In addition, in 2006, the State of California adopted a comprehensive law designed to reduce greenhouse gas emissions in the state. As discussed above, this statute and the regulations developed to implement its requirements will affect the operation of stationary and mobile sources and may require reformulation of fuels to lower their carbon "footprint."

Government Regulation and Environmental Matters

Certain aspects of our operations are subject to regulation under federal, state, local and foreign laws. If we were to violate these laws or if the laws, or enforcement proceedings were to change, it could have a material adverse effect on our business, financial condition and results of operations.

Regulations that significantly impact our operations are described below.

- *CNG and LNG stations*—To construct a CNG or LNG fueling station, we must obtain a facility permit from the local fire department and either we or a third party contractor must be licensed as a general engineering contractor. The installation of each CNG and LNG fueling station must be in accordance with federal, state and local regulations pertaining to station design, environmental health, accidental release prevention, above-ground storage tanks, hazardous waste and hazardous materials. We are also required to register with certain state agencies as a retailer/wholesaler of CNG and LNG.

- *Transfer of LNG*—Federal Safety Standards require each transfer of LNG to be conducted in accordance with specific written safety procedures. These procedures must be located at each place of transfer and must include provisions for personnel to be in constant attendance during all LNG transfer operations.

- *LNG liquefaction plants*—To build and operate LNG liquefaction plants, we must apply for facility permits or licenses to address many factors, including storm water or wastewater discharges, waste handling and air emissions related to production activities or equipment operations. The construction of LNG plants must also be approved by local planning boards and fire departments.

- *Financing*—State agencies generally require the registration of finance lenders. For example, in California, pursuant to the California Finance Lenders Law, one of our subsidiaries is a registered finance lender with the California Department of Corporations.

- *Vehicle conversion*—Vehicles that are converted to run on natural gas and sold by BAF are subject to EPA emission requirements and certifications, federal vehicle safety regulations and, in some cases, such as California, state emission requirements and certifications.

- *Natural gas fueling compressors*—CNG fueling equipment is manufactured to meet the electrical and mechanical design standards of the country where the equipment will be installed. Our manufacturing facility in Canada is registered with the British Columbia Safety Authority and the Society of Mechanical Engineers for manufacturing and operating pressure vessels.

- *Biomethane*—Our DCE biomethane production facility, and the biomethane facility we plan to build in Michigan, are required to comply with their Title V air permits as well as EPA regulations covering the collection of landfill gas. In addition, our biomethane projects must produce biomethane that meets the gas quality specifications of the local utilities that accept the gas. These specifications are approved by the relevant state utilities commission. In California, the gas utilities pipeline specifications prohibit the injection of landfill gas. If the gas utilities that we rely upon to accept and ship our biomethane product adopt new gas specifications or otherwise refuse to accept our biomethane product, we will be unable to sell the product and generate revenues.

We believe we are in substantial compliance with environmental laws and regulations and other known regulatory requirements. Compliance with these regulations has not had a material effect on our capital expenditures, earnings or competitive position. It is possible that more stringent environmental laws and regulations may be imposed in the future, such as more rigorous air emissions requirements or proposals to make waste materials subject to more stringent and costly handling, disposal and clean-up requirements and regulations of greenhouse gas emissions from our LNG plants or stations. Accordingly, new laws or regulations or amendments to existing laws or regulations might require us to undertake significant capital expenditures, which may have a material adverse effect on our business, consolidated financial condition, results of operations and cash flows.

Employees

As of December 31, 2010, we employed 710 people, of whom 71 were in sales and marketing (including our grants department), 554 were in operations, engineering, vehicle and compressor production, and 85 were in finance and administration. We have not experienced any work stoppages and none of our employees is subject to collective bargaining agreements. We believe that our employee relations are good.

Financial Information about Segments and Geographic Areas

We operate our business in one reportable segment. For information about our revenues from external customers, operating income (loss) and long-lived assets broken down by geographic area, see note 12 to our consolidated financial statements.

Additional Information

Our web site is located at www.cleanenergyfuels.com. We make available free of charge on our web site our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. The reference to our website is intended to be an inactive textual reference and the contents of our website are not intended to be incorporated into this report.

Item 1A.—Risk Factors

An investment in our Company involves a high degree of risk of loss. You should carefully consider the risk factors discussed below and all of the other information included in this report before you decide to purchase shares of our common stock. We believe the risks and uncertainties described below are the most significant we face. The occurrence of any of the following risks could harm our business. In that case, the *trading price of our common stock could decline. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our operations.*

We have a history of losses and may incur additional losses in the future.

In 2008, 2009 and 2010 we incurred pre-tax losses of $44.3 million, $33.4 million, and $4.2 million, respectively. Our loss for 2008 includes $18.6 million in expenses associated with our support for Proposition 10, the California Alternative Fuel Vehicles and Renewable Energy ballot initiative. Our loss for 2009 includes $17.4 million of derivative losses related to marking to market the value of our Series I warrants, and our loss during 2010 was decreased by a derivative gain of $10.3 million on our Series I warrants. During 2008, 2009 and 2010, our losses were substantially decreased by our receipt of approximately $17.2 million, $15.5 million and $16.0 million of revenue from federal fuel tax credits, respectively. In order to execute our strategy and improve our financial performance, we must continue to invest in developing the natural gas vehicle fuel market and offer our customers compelling natural gas fuel prices. If we do not achieve or maintain profitability that can be sustained in the absence of federal fuel tax credits, our business will suffer and the price of our common stock may drop. In addition, if the price of our common stock increases during future periods when our Series I warrants are outstanding, we may be required to recognize material losses based on the valuation of the outstanding Series I warrants.

A material portion of our historical revenues are associated with a federal fuel excise tax credit that expires on December 31, 2011.

The federal excise tax credit of $0.50 per gasoline gallon equivalent of CNG and liquid gallon of LNG sold for vehicle fuel use, which began on October 1, 2006, expires December 31, 2011. Based on the service relationship we have with our customers, either we or our customers are able to claim the credit. In 2008, 2009 and 2010, we recorded approximately $17.2 million, $15.5 million and $16.0 million of revenue, respectively, related to fuel tax credits, representing approximately 13.7%, 11.8% and 7.6%, respectively, of our total revenue during the periods. On July 15, 2010, the IRS sent us a letter disallowing approximately $5.1 million related to certain excise tax credit claims we made from October 1, 2006 to June 30, 2008. If we are unsuccessful in appealing the IRS disallowance of these claims, we may be required to refund some or all of the $5.1 million in contested claims.

We will need to raise debt or equity capital to continue to fund the growth of our business.

We will be required to raise debt or equity capital to fund the growth of our business. Our business plan for 2011 calls for approximately $80.7 million in capital expenditures. We may also require capital for unanticipated expenses, mergers and acquisitions and strategic investments. In addition, we have committed to significant future payments that we will be required to make in connection with our acquisition of IMW and Northstar. At March 10, 2011, our future payments for IMW and Northstar totaled $37.5 million and $7.5 million, respectively. Also at December 31, 2010, we have agreed to pay up to $40.0 million as additional consideration related to our IMW acquisition if certain performance measurements of IMW are met.

Equity or debt financing options may not be available on terms favorable to us or at all, particularly if there are no effective federal incentives supporting the growth of the natural gas fueling business. Additional sales of our common stock or securities convertible into our common stock will dilute existing stockholders and may result in a decline in our stock price. We may also pursue debt financing options including, but not limited to, equipment financing, the sale of convertible promissory notes or commercial bank financing. Recent economic turmoil and severe lack of liquidity in the debt capital markets and volatility in the equity capital markets have adversely affected capital raising opportunities. If we are unable to obtain debt or equity financing in amounts sufficient to fund any unanticipated expenses, capital expenditures, mergers, acquisitions or strategic investments, we will be forced to suspend or curtail these capital expenditures or postpone or delay potential acquisitions or other strategic transactions, which could harm our business, results of operations, and future prospects.

Boone Pickens, our largest shareholder, holds a warrant to purchase 15,000,000 shares of our common stock at $10 per share that expires on December 28, 2011. To the extent this warrant is exercised as a whole or in part, we would receive cash proceeds. However, there can be no assurances that the warrant will be exercised as a whole or in part.

Our growth is influenced by tax and related government incentives for clean burning fuels and alternative fuel vehicles. A reduction in these incentives or the failure to pass new legislation with new incentive programs will increase the cost of natural gas fuel and vehicles for our customers and may reduce our revenue.

Our business is influenced by tax credits, rebates and similar federal, state and local government incentives that promote the use of natural gas as a vehicle fuel in the United States. The federal income tax credit that was available to offset 50% to 80% of the incremental cost of purchasing new or converted natural gas vehicles expired on December 31, 2010. The absence of these vehicle tax credits could have a detrimental effect on the natural gas vehicle and fueling industry, including sales at our wholly owned subsidiary, BAF, and adversely affect our results of operations and financial performance. Our business plan and the ability of our business to successfully grow depends in part on the extension of the federal fuel excise tax credit for natural gas vehicle fuel, the reinstatement and extension of the federal income tax credit for the purchase of natural gas vehicles and the passage of legislation providing for additional incentives for the sale and use of natural gas vehicles. If existing federal incentives are not reinstated or extended and if new incentives are not passed, fewer natural gas vehicles will be sold and used and our revenue and financial performance will be adversely affected. Furthermore, the failure of certain federal, state or local government incentives which promote the use of natural gas as a vehicle fuel to pass into law could result in a negative perception by the market generally and a decline in the market price of our common stock. In addition, if grant funds are no longer available under existing government programs for the purchase and construction of natural gas vehicles and stations, the purchase of natural gas vehicles and station construction could slow and our business and results of operations will be adversely affected. Continued reduction in tax revenues associated with high unemployment rates, economic recession or slow-down could result in a significant reduction in funds available for government grants that support vehicle conversion and station construction, which could impair our ability to grow our business.

Automobile and engine manufacturers produce very few originally manufactured natural gas vehicles and engines for the United States and Canadian markets, which may restrict our sales.

Limited availability of natural gas vehicles and engine sizes for heavy duty vehicles restricts their wide scale introduction and narrows our potential customer base. Original equipment manufacturers produce a small number of natural gas engines and vehicles, and they may not make adequate investments to expand their natural gas engine and vehicle product lines. For the North American market, there is only one major automobile manufacturer that makes natural gas powered passenger vehicles, and major manufacturers of medium and heavy duty vehicles produce only a narrow range and number of natural gas vehicles. The technology utilized in some of the heavy duty vehicles that run on LNG is also relatively new and has not been previously deployed or used in large numbers of vehicles. As a result, these vehicles may require servicing and further technology refinements to address performance issues that may occur as vehicles are deployed in large numbers and are operated under strenuous conditions. If potential heavy duty LNG truck purchasers are not satisfied with truck performance, or additional heavy-duty truck engine manufacturers do not enter the market for LNG engines, it may delay, impair, or eliminate the growth of our LNG fueling business, which would impair our financial performance. Further, North American car and truck manufacturers are facing significant economic challenges that may make it difficult or impossible for them to introduce new natural gas vehicles in the North American market or continue to manufacture and support the limited number of available natural gas vehicles. Due to the limited supply of natural gas vehicles, our ability to promote natural gas vehicles and our natural gas fuel sales may be restricted, even if there is demand.

Decreases in the price of oil, gasoline and diesel fuel without similar decreases in the price of natural gas may slow the growth of our business and negatively impact our financial results.

Prices for oil, gasoline and diesel fuel have declined substantially from the high prices reached in the summer of 2008. The price of a barrel of crude oil has declined from a high of $148.35 per barrel reached on July 11, 2008 to a price of $91.38 per barrel on December 31, 2010. Average retail prices for ultra low sulfur diesel fuel in California have declined from a high of $5.03 in June 2008 to $3.47 per gallon at December 31, 2010, and average retail prices for gasoline in California have declined from a high of $4.59 per gallon in June 2008 to $3.33 per gallon at December 31, 2010. The decrease in the price of diesel and gasoline, in particular, results in reduced interest in alternative fuels such as LNG and CNG. Decreased interest in alternative fuels will slow the growth of our business. In addition, to the extent that we price our CNG and LNG fuel at a discount to these reduced diesel or gasoline prices in an effort to attract new and retain existing customers, our profit margin on fuel sales may be harmed and our financial results negatively impacted. Our retail prices for LNG fuel in California decreased from $3.70 per diesel gallon equivalent in July of 2008 to $2.50 per diesel gallon equivalent at December 31, 2010, and our retail prices for CNG fuel sold in the Los Angeles basin decreased from a high of $3.30 per gasoline gallon equivalent in July of 2008 to $2.60 per gasoline gallon equivalent at December 31, 2010. Lower fuel prices for CNG and LNG as a result of lower natural gas commodity prices also will reduce our revenues. At March 10, 2011, oil, diesel and gasoline prices have increased from their December 31, 2010 amounts, but are still below their high prices reached in 2008.

If the prices of CNG and LNG do not remain sufficiently below the prices of gasoline and diesel, potential fleet customers will have less incentive to purchase natural gas vehicles, which would decrease demand for CNG and LNG and limit our growth.

Natural gas vehicles cost more than comparable gasoline or diesel powered vehicles because converting a vehicle to use natural gas adds to its base cost. If the prices of CNG and LNG do not remain sufficiently below the prices of gasoline or diesel, fleet operators may be unable to recover the additional costs of acquiring or converting to natural gas vehicles in a timely manner, and they may choose not to use natural gas vehicles. Our ability to offer CNG and LNG fuel to our customers at lower prices than gasoline and diesel depends in part on natural gas prices remaining lower, on an energy equivalent basis, than oil prices. If the price of oil declines and the price of natural gas increases, it will make it more difficult for us to offer our customers discounted prices for CNG and LNG as compared to gasoline and diesel prices and maintain an acceptable margin on our sales. Recent and significant volatility in oil and gasoline prices demonstrate that it is difficult to predict future transportation fuel costs. In addition, any new regulations imposed on natural gas extraction in the United States, particularly on extraction of natural gas from shale formations, could increase the costs of domestic gas production or make it more costly to produce natural gas in the United States, which could lead to substantial increases in the price of natural gas. Reduced prices for gasoline and diesel fuel, combined with higher costs for natural gas and natural gas vehicles, may cause potential customers to delay or reject converting their fleets to run on natural gas. In that event, our sales of natural gas fuel and vehicles would be slowed and our business would suffer.

The volatility of natural gas prices could adversely impact the adoption of CNG and LNG vehicle fuel and our business.

In the recent past, the price of natural gas has been volatile, and this volatility may continue. From the end of 1999 through December 31, 2010, the price for natural gas, based on the NYMEX daily futures data, ranged from a low of $1.65 per Mcf to a high of $19.38 per Mcf. At December 31, 2010, the NYMEX index price for natural gas was $4.27 per Mcf. Increased natural gas prices affect the cost to us of natural gas and will adversely impact our operating margins in cases where we have committed to sell natural gas at a fixed price without an effective futures contract in place that fully mitigates the price risk or where we otherwise cannot pass on the increased costs to our customers. In addition, higher natural gas prices may cause CNG and LNG to cost as much as or more than gasoline and diesel generally, which would adversely impact the adoption of CNG and LNG as a vehicle fuel. Conversely, lower natural gas prices reduce our revenues due to the fact that in a significant amount of our customer agreements, the commodity cost is passed through to the customer. Among the factors that can cause price fluctuations in natural gas prices are changes in domestic and foreign supplies of natural gas, domestic storage levels, crude oil prices, the price difference between crude oil and natural gas, price and availability of alternative fuels, weather conditions, negative publicity surrounding drilling techniques, level of consumer demand, economic conditions, price of foreign natural gas imports, and domestic and foreign governmental regulations and political conditions. In particular, there have been recent legislative efforts to place new regulatory requirements on the production of natural gas by hydraulic fracturing of shale gas reservoirs. Hydraulic fracturing of shale gas reservoirs has resulted in a substantial increase in the proven natural gas reserves in the United States, and any change in regulations that makes it more expensive or unprofitable to produce natural gas through hydraulic fracturing could lead to increased natural gas prices. The recent economic recession and increased domestic natural gas supplies have contributed to significant declines in the price of natural gas since the summer of 2008.

Our growth depends in part on environmental regulations and programs mandating the use of cleaner burning fuels, and modification or repeal of these regulations may adversely impact our business.

Our business depends in part on environmental regulations and programs in the United States that promote or mandate the use of cleaner burning fuels, including natural gas for vehicles. Industry participants with a vested interest in gasoline and diesel, many of which have substantially greater resources than we do, invest significant time and money in an effort to influence environmental regulations in ways that delay or repeal requirements for cleaner vehicle emissions. Further, an economic recession may result in the delay, amendment or waiver of environmental regulations due to the perception that they impose increased costs on the transportation industry that cannot be absorbed in a contracting economy. For example, the Clean Trucks Program at the Ports of Los Angeles and Long Beach formerly called for the replacement of a set number of drayage trucks with "clean" trucks, but due to economic conditions and other factors, the Clean Trucks Program no longer calls for any specific number of "clean" truck replacements. In addition, many of the clean trucks that have been deployed have been clean diesel trucks which are generally less expensive than LNG trucks. There have also been recent ballot initiatives commenced in the State of California and political support for postponing or delaying California's implementation of AB 32, also known as the Global Warming Solutions Act of 2006, which is intended to reduce greenhouse gas emissions. CNG, LNG and biomethane vehicle fuel all produce fewer greenhouse gases than gasoline or diesel fuel and the delay or repeal of AB 32, and in particular California's low-carbon fuel standard, could reduce the appeal of natural gas fuel for our customers and reduce our revenue. The delay, repeal or modification of federal or state regulations or programs that encourage the use of cleaner vehicles could also have a detrimental effect on the United States natural gas vehicle industry, which, in turn, could slow our growth and adversely affect our business.

The use of natural gas as a vehicle fuel may not become sufficiently accepted for us to expand our business.

To expand our business, we must develop new fleet customers and obtain and fulfill CNG and LNG fueling contracts from these customers. We cannot guarantee that we will be able to develop these customers or obtain these fueling contracts. Whether we will be able to expand our customer base will depend on a number of factors, including the level of acceptance and availability of natural gas vehicles, the growth in our target markets of fueling station infrastructure that supports CNG and LNG sales and our ability to supply CNG and LNG at competitive prices. The decline in oil, diesel and gasoline prices from the levels they reached during the summer of 2008 has resulted in decreased interest in alternative fuels like CNG and LNG. In addition, the disruption in the capital markets that began in 2008 has reduced the availability of debt financing to support the purchase of CNG and LNG vehicles and investment in CNG and LNG infrastructure. If our potential customers are unable to access credit to purchase natural gas vehicles, it may make it difficult or impossible for them to invest in natural gas vehicle fleets, which would impair the ability of our business to grow.

Our global operations expose us to additional risk and uncertainties.

We have operations in a number of countries, including the United States, Canada, China, Colombia, Bangladesh and Peru. Our global operations may be subject to risks that may limit our ability to operate our business. Our natural gas compression equipment is primarily manufactured in Canada and sold globally, which exposes us to a number of risks that can arise from international trade transactions, local business practices and cultural considerations, including:

- political unrest, terrorism and economic or financial instability;
- unexpected changes in regulatory requirements and uncertainty related to developing legal and regulatory systems governing economic and business activities, real property ownership and application of contract rights;
- import-export regulations;
- difficulties in enforcing agreements and collecting receivables;
- difficulties in ensuring compliance with the laws and regulations of multiple jurisdictions;
- difficulties in ensuring that health, safety, environmental and other working conditions are properly implemented and/or maintained by the local office;
- changes in labor practices, including wage inflation, labor unrest and unionization policies;
- limited intellectual property protection;
- longer payment cycles by international customers;
- currency exchange fluctuations;
- inadequate local infrastructure and disruptions of service from utilities or telecommunications providers, including electricity shortages;
- potentially adverse tax consequences; and
- differing employment practices and labor issues.

We also face risks associated with currency exchange and convertibility, inflation and repatriation of earnings as a result of our foreign operations. In some countries, economic, monetary and regulatory factors could affect our ability to convert funds to U.S. dollars or move funds from accounts in these countries. We are also vulnerable to appreciation or depreciation of foreign currencies against the U.S. dollar. We do not currently engage in currency hedging activities to limit the risks of currency fluctuations.

We may not be successful in managing or integrating IMW into our business, which could prevent us from realizing the expected benefits of the acquisition and could adversely affect our future results.

The integration of IMW into our business presents significant challenges and risks to our business, including (i) the distraction of management from other business concerns, (ii) the retention of customers of IMW, (iii) expansion into foreign markets, (iv) the introduction of IMW's compressor and related equipment manufacturing and servicing business, which is a new product line for us, (v) achievement of appropriate internal controls over financial reporting and (vi) the monitoring of compliance with all laws and regulations. The vast majority of IMW's revenue is derived from sales in emerging markets, and IMW has not previously been required to comply with the U.S. Foreign Corruption Practices Act or any of the requirements of Sarbanes-Oxley. If we do not successfully integrate IMW into our business and maintain regulatory compliance, we may not realize the benefits expected from the acquisition and our results of operations could be materially adversely affected. If the revenue of IMW declines or grows more slowly than we anticipate, or if its operating expenses are higher than we expect, we may not be able to achieve, sustain or increase the growth of our business, in which case our financial condition will suffer and our stock price could decline. In addition, the operations of IMW do not have the disclosure controls and procedures or internal controls over financial reporting that are as thorough or effective as those required for a public company. Although we intend to implement appropriate controls and procedures as we integrate the operations of IMW, we cannot provide assurance as to the effectiveness of the disclosure controls and procedures or internal controls over financial reporting of IMW until we have fully integrated them.

A significant portion of the purchase price of IMW was allocated to goodwill and a write-off of all or part of this goodwill could adversely affect our operating results.

Under business combination accounting standards, we allocated the total purchase price of IMW to its net tangible assets and liabilities and intangible assets based on their fair values as of the date of the acquisition and recorded the excess of the purchase price over those values as goodwill. Our estimates of the fair value of the assets and liabilities of IMW were based upon certain assumptions, including assumptions about and anticipated attainment of new business, believed to be reasonable, but which are inherently uncertain. Pursuant to the applicable accounting standards, we allocated $45.0 million of the purchase price for IMW to goodwill. Our goodwill could be impaired if developments affecting the acquired compressor manufacturing operations or the markets in which IMW produces and/or sells compressors lead us to conclude that the cash flows we expect to derive from its manufacturing operations will be substantially reduced. An impairment of all or part of our goodwill could adversely affect our results of operations and financial condition.

We may not be successful in managing or integrating our recently acquired subsidiary, Northstar, with our existing operations.

On December 15, 2010 we acquired Northstar, a leading provider of design, engineering, construction and maintenance services for LNG and LCNG fueling stations. Our ability to realize benefits from the acquisition depends on the growth of the LNG fueling market and our ability to successfully integrate Northstar's business with our existing operations. We cannot provide any assurances that the LNG fueling market, or Northstar's business, will grow or that we will successfully manage the integration of Northstar's business with our existing operations. In addition, the Northstar operations do not have the disclosure controls and procedures or internal controls over financial reporting that are as thorough or effective as those required for public companies. Although we intend to implement appropriate controls and procedures as we integrate the Northstar operations, we cannot provide assurance as to the effectiveness of Northstar's disclosure controls and procedures or internal controls over financial reporting until we have fully integrated them.

Failure to comply with the terms of our Credit Agreement with PlainsCapital Bank could impair our rights in DCE and other secured property.

In August 2008, we acquired a 70% interest in DCE, which manages a biomethane production facility at the McCommas Bluff landfill in Dallas, Texas, and holds a lease to the associated landfill gas development rights. We borrowed $18 million from PCB to fund the acquisition and obtained a $12 million line of credit from PCB to pay certain costs and expenses of the acquisition and finance capital improvements of the gas processing plant through a loan made by us to DCE. We have used $12.0 million of the line of credit from PCB, and the outstanding balance was $9.9 million as of December 31, 2010. In October 2009, we repaid the $18 million loan that we used to fund the acquisition of DCE and amended the Credit Agreement to obtain a $20 million line of credit from PCB to finance capital expenditures and working capital for our operations, and for other general business purposes. As of the date of filing of this Form 10-K for the period ending December 31, 2010, we had not borrowed any money under the $20 million line of credit. To secure our obligations under the Credit Agreement, we granted PCB a security interest in 45 of our LNG tanker trailers, certain accounts receivable and inventory, and our note receivable from, and our membership interests in, DCE. Our Credit Agreement with PCB requires that we comply with certain covenants. One of the covenants requires that we maintain accounts receivable balances from certain subsidiaries above $8 million at each quarter-end during the term. To the extent natural gas prices fall, which would result in decreased revenues, or our volumes sold decline, we could violate this covenant. Also, beginning with the quarter ended June 30, 2009, we have been required to maintain a specific minimum debt service ratio. Should our operating results not materialize as planned, we could violate this covenant. In computing our covenant compliance, we exclude the financial results and amounts of IMW. If we were to violate a covenant, we would seek a waiver from the bank, which the bank is not obligated to grant. If the bank does not grant a waiver, all of the obligations under the Credit Agreement will become immediately due and payable and $2.5 million of our funds held by PCB would be applied to the balance due on the PCB loans. We also would be unable to use the $20 million PCB line of credit if this were to occur.

The infrastructure to support gasoline and diesel consumption is vastly more developed than the infrastructure for natural gas vehicle fuels.

Gasoline and diesel fueling stations and service infrastructure are widely available in the United States. For natural gas vehicle fuels to achieve more widespread use in the United States and Canada, they will require a promotional and educational effort and the development and supply of more natural gas vehicles and fueling stations. This will require significant continued effort by us, as well as government and clean air groups, and we may face resistance from oil companies and other vehicle fuel companies. A prolonged economic recession or disruption in the capital markets may make it difficult or impossible to obtain financing to expand the natural gas vehicle fueling infrastructure and impair our ability to grow our business. There is no assurance natural gas will ever achieve the level of acceptance as a vehicle fuel necessary for us to expand our business significantly.

We have significant contracts with federal, state and local government entities that are subject to unique risks.

We have existing, and will continue to seek, long-term LNG and CNG station construction, maintenance and fuel sales contracts with various federal, state and local governmental bodies, which accounted for approximately 53% of our annual revenues from 2006 through 2010. In May and June 2009, we spent $5.6 million to acquire four new CNG operation and maintenance contracts with government agencies. In addition to our normal business risks, our contracts with these government entities are often subject to unique risks, some of which are beyond our control. Long-term government contracts and related orders are subject to cancellation if appropriations for subsequent performance periods are not made. The termination of funding for a government program supporting any of our CNG or LNG operations could result in a loss of anticipated future revenues attributable to that program, which could have a negative impact on our operations. In addition, government entities with whom we contract are often able to modify, curtail or terminate contracts with us without prior notice at their convenience, and are only liable for payment for work done and commitments made at the time of termination. Modification, curtailment or termination of significant contracts could have a material adverse effect on our results of operations and financial condition. In particular, if any of the contracts we recently acquired are terminated, we may be unable to recover our investment in acquiring the contracts. On December 31, 2010, we recorded an impairment charge of $1.5 million related to one of the contracts mentioned above when we lost the contract through a competitive bid process.

The budget deficits being experienced by many governmental entities may reduce the available funding for certain natural gas programs and services and the purchase of CNG or LNG fuel, which could reduce our revenue and impair our financial performance.

Many governmental entities are experiencing significant budget deficits as a result of the economic recession, which has and may continue to reduce or curtail their ability to fund natural gas fuel programs, purchase natural gas vehicles or provide public transportation and services, which would harm our business. Our contracts with governmental entities constituted approximately 53% of our revenues from 2006 to 2010. Furthermore, in response to budget deficits, such governmental entities have and may continue to request or demand that we lower our price for CNG or LNG fuel. Since we compete for several of our contracts with government entities through a competitive bidding process, in order to be awarded new contracts or for the renewal of an expired contract, we may have to agree to lower prices for CNG fuel, LNG fuel and our operations and maintenance services. For example, the Metropolitan Transit System of San Diego, which represented approximately 6.0 million gallons of CNG in 2009, conducted a competitive bidding procurement and awarded the contract to a competitor on July 27, 2010. The Washington Metropolitan Area Transit Authority, which represented approximately 6.3 million gallons of CNG in 2010, also conducted a competitive bidding procurement which resulted in the award of that contract to a competitor on December 31, 2010. Government deficits, spending reductions and competitive bidding procurement processes could reduce our margins on fuel sales, lower our revenue and impair our financial performance.

Conversion of vehicles to run on natural gas is time-consuming and expensive and may limit the growth of our sales.

Conversion of vehicle engines from gasoline or diesel to natural gas is performed by only a small number of vehicle conversion suppliers (including our wholly owned subsidiary, BAF) that must meet stringent safety and engine emissions certification standards. The engine certification process is time consuming and expensive and raises vehicle costs. In addition, conversion of vehicle engines from gasoline or diesel to natural gas may result in vehicle performance issues or increased maintenance costs that could discourage our potential customers from purchasing converted vehicles that run on natural gas and impair the financial performance of our recently acquired subsidiary, BAF. Without an increase in vehicle conversion options, reduced vehicle conversion costs and improved vehicle conversion performance, our sales of natural gas vehicle fuel and converted natural gas vehicles, through BAF, may be restricted and our revenue will be reduced both by less demand for natural gas vehicle fuel and less demand for converted natural gas vehicles.

A majority of BAF's sales of CNG vehicles are to one customer. If this customer does not continue to purchase CNG vehicles, then revenue at our wholly owned subsidiary, BAF, will decline and our financial results will be impaired.

During 2009 and 2010, BAF derived approximately 63% and 66%, respectively, of its revenue from AT&T. AT&T is not required to purchase any CNG vehicle conversion kits under its agreement with BAF and the agreement and all purchase orders submitted by AT&T under the agreement may be cancelled by AT&T at any time for any reason. If AT&T does not continue to order and pay for CNG vehicle conversion kits produced by BAF, then BAF's sales revenue will substantially decline and our financial performance may suffer. AT&T has indicated that they may reduce or delay conversion of additional vehicles during 2011 in order to allow for a build-out of infrastructure to support fueling the vehicles. In the absence of continued sales to AT&T, BAF will experience materially reduced revenues and may require additional cash to continue its operations, which could drain our capital resources.

If there are advances in other alternative vehicle fuels or technologies, or if there are improvements in gasoline, diesel or hybrid engines, demand for natural gas vehicles may decline and our business may suffer.

Technological advances in the production, delivery and use of alternative fuels that are, or are perceived to be, cleaner, more cost-effective or more readily available than CNG or LNG have the potential to slow adoption of natural gas vehicles. Advances in gasoline and diesel engine technology, especially hybrids, may offer a cleaner, more cost-effective option and make fleet customers less likely to convert their fleets to natural gas. Technological advances related to ethanol or biodiesel, which are increasingly used as an additive to, or substitute for, gasoline and diesel fuel, may slow the need to diversify fuels and affect the growth of the natural gas vehicle market. In addition, a prototype heavy duty electric truck model was recently introduced at the ports of Los Angeles and Long Beach. Use of electric heavy duty trucks or the perception that electric heavy duty trucks may soon be widely available and provide satisfactory performance in heavy duty applications may reduce demand for heavy duty LNG trucks. In addition, hydrogen and other alternative fuels in experimental or developmental stages may eventually offer a cleaner, more cost-effective alternative to gasoline and diesel than natural gas. Advances in technology that slow the growth of or conversion to natural gas vehicles, or which otherwise reduce demand for natural gas as a vehicle fuel, will have an adverse effect on our business. Failure of natural gas vehicle technology to advance at a sufficient pace may also limit its adoption and our ability to compete with other alternative fuels and alternative fuel vehicles.

Our ability to supply LNG to new and existing customers is restricted by limited production of LNG and by our ability to acquire LNG without interruption and near our target markets.

Production of LNG in the United States is fragmented. LNG is produced at a variety of smaller natural gas plants around the United States, as well as at larger plants. It may become difficult for us to obtain additional LNG without interruption and near our current or target markets at competitive prices. If our LNG liquefaction plants, or any of those from which we purchase LNG, are damaged by severe weather, earthquake or other natural disaster, or otherwise experience prolonged downtime, our LNG supply will be restricted. Currently, one of the suppliers from whom we obtain LNG has experienced unscheduled plant shut downs and has been unable to maintain minimum production levels on a consistent basis, which has caused us to incur additional costs to obtain LNG from other sources. If we are unable to supply enough of our own LNG or purchase it from third parties to meet existing customer demand, we may be liable to our customers for penalties. Our growth plans, if successful, will require substantial growth in the available LNG supply across the United States, and if this supply is unavailable, it will constrain our ability to increase the market for LNG fuel including supplying LNG fuel to heavy duty truck customers. An LNG supply interruption or LNG demand that exceeds available supply will also limit our ability to expand LNG sales to new customers and could disrupt our relationship with existing customers, which would hinder our growth. Furthermore, because transportation of LNG is relatively expensive, if we are required to supply LNG to our customers from distant locations and cannot pass these costs through to our customers, our operating margins will decrease on those sales due to our increased transportation costs.

LNG supply purchase commitments may exceed demand causing our costs to increase and impacting our LNG sales margins.

Two of our LNG supply agreements have a take or pay commitment and our California LNG liquefaction plant has a land lease and other fixed operating costs regardless of production and sales levels. The take or pay commitments require us to pay for the LNG that we have agreed to purchase irrespective of whether we can sell the LNG to our own customers. For example, the LNG Sales Agreement that we entered into with DGS on October 17, 2007 has a ten year term and, provided that Plant Capacity (as defined in the LNG Sales Agreement) is available to be taken by us, the plant is not shut down by DGS and no event beyond our reasonable control prevents us from taking delivery of LNG, we are committed to purchasing at least 45,000 gallons of LNG per day. Should the market demand for LNG decline, or if we lose significant LNG customers or if demand under any existing or any future LNG supply contract does not maintain its volume levels or grow, overall operating and supply costs may increase as a percentage of revenue and negatively impact our margins.

One of our third-party LNG suppliers may cancel its supply contract with us on short notice or increase its LNG prices, which would hinder our ability to meet customer demand and increase our costs.

Under certain circumstances, Williams Gas Processing Company ("Williams") may terminate our LNG supply contract with them on short notice. Williams may also significantly increase the price of LNG we purchase upon 24 hours' notice if their costs to produce LNG increases, and we may be required to reimburse them for certain other expenses. Our contract with Williams, which supplied 29% of the LNG we sold for the year ended December 31, 2008, 14% for the year ended December 31, 2009, and 13.2% for the year ended December 31, 2010, expires on June 30, 2011. Furthermore, there are a limited number of LNG suppliers in or near the areas where our LNG customers are located. It may be difficult to replace an LNG supplier, and we may be unable to obtain alternate suppliers at acceptable prices, in a timely manner, or at all. If significant supply interruptions occur, our ability to meet customer demand will be impaired, customers may cancel orders and we may be subject to supply interruption penalties. If we are subject to LNG price increases, our operating margins may be impaired and we may be forced to sell LNG at a loss under our LNG supply contracts.

If we are unable to obtain natural gas in the amounts needed on a timely basis or at reasonable prices, we could experience an interruption of CNG or LNG deliveries or increases in CNG or LNG costs, either of which could have an adverse effect on our business.

Some regions of the United States and Canada depend heavily on natural gas supplies coming from particular fields or pipelines. Interruptions in field production or in pipeline capacity could reduce the availability of natural gas or possibly create a supply imbalance that increases natural gas prices. We have in the past experienced LNG supply disruptions due to severe weather in the Gulf of Mexico and plant outages. If there are interruptions in field production, insufficient pipeline capacity, equipment failure on liquefaction production or delivery delays, we may experience supply stoppages which could result in our inability to fulfill delivery commitments. This could result in our being liable for contractual damages and daily penalties or otherwise adversely affect our business.

Oil companies, industrial gas companies, and natural gas utilities, which have far greater resources and brand awareness than we have, may expand into the natural gas fuel market, which could harm our business and prospects.

There are numerous potential competitors who could enter the market for CNG and LNG vehicle fuels. Many of these potential entrants, such as integrated oil companies, industrial gas companies, and natural gas utilities, have far greater resources and brand awareness than we have. Natural gas utilities, particularly in California, continue to own and operate natural gas fueling stations that compete with our stations. If the use of natural gas vehicles and demand for natural gas vehicle fuel increases, these companies may find it more attractive to enter or expand their operations in the market for natural gas vehicle fuels and we may experience increased pricing pressure, reduced operating margins and fewer expansion opportunities.

If we do not have effective futures contracts in place, increases in natural gas prices may cause us to lose money.

From 2005 to 2008, we sold and delivered approximately 30% of our total gasoline gallon equivalents of CNG and LNG under contracts that provided a fixed price or a price cap to our customers over terms typically ranging from one to three years, and in some cases up to five years. At any given time, however, the market price of natural gas may rise and our obligations to sell fuel under fixed price contracts may be at prices lower than our fuel purchase price if we do not have effective futures contracts in place. This circumstance has in the past and may again in the future compel us to sell fuel at a loss, which would adversely affect our results of operations and financial condition. Commencing with the adoption of our revised natural gas hedging policy in February 2007, our policy has been to purchase futures contracts to hedge our exposure to natural gas price variability related to our fixed price contracts. Such contracts, however, may not be available or we may not have sufficient financial resources to secure such contracts. In addition, under our hedging policy, we may reduce or remove futures contracts we have in place related to these contracts if such disposition is approved in advance by our board of directors and derivative committee. If we are not economically hedged with respect to our fixed price contracts, we will lose money in connection with those contracts during periods in which natural gas prices increase above the prices of natural gas included in our customers' contracts. As of December 31, 2010, we were economically hedged with respect to our fixed price contracts with our customers.

Our futures contracts may not be as effective as we intend.

Our purchase of futures contracts can result in substantial losses under various circumstances, including if we do not accurately estimate the volume requirements under our fixed price customer contracts when determining the volumes included in the futures contracts we purchase, or we elect to purchase a futures contract in connection with a bid proposal and ultimately we are not awarded the entire contract or our customer does not fully perform its obligations under the awarded contract. We also could incur significant losses if a counterparty does not perform its obligations under the applicable futures arrangement, the futures arrangement is economically imperfect or ineffective, or our futures policies and procedures are not properly followed or do not work as planned. Furthermore, we cannot be assured that the steps we take to monitor our futures activities will detect and prevent violations of our risk management policies and procedures.

A decline in the value of our futures contracts may result in margin calls that would adversely impact our liquidity.

We are required to maintain a margin account to cover losses related to our natural gas futures contracts. Futures contracts are valued daily, and if our contracts are in loss positions at the end of a trading day, our broker will transfer the amount of the losses from our margin account to a clearinghouse. If at any time the funds in our margin account drop below a specified maintenance level, our broker will issue a margin call that requires us to restore the balance. Payments we make to satisfy margin calls will reduce our cash reserves, adversely impact our liquidity and may also adversely impact our ability to expand our business. Moreover, if we are unable to satisfy the margin calls related to our futures contracts, our broker may sell these contracts to restore the margin requirement at a substantial loss to us. As of December 31, 2010, we had $6.5 million on deposit related to our futures contracts.

If our futures contracts do not qualify for hedge accounting, our net income (loss) and stockholders' equity will fluctuate more significantly from quarter to quarter based on fluctuations in the market value of our futures contracts.

We account for our futures activities under the relevant derivative accounting guidance, which requires us to value our futures contracts at fair market value in our financial statements. Prior to June 2008, our futures contracts did not qualify for hedge accounting, and therefore we have recorded any changes in the fair market value of these contracts directly in our consolidated statements of operations in the line item "derivative (gains) losses" along with any realized gains or losses during the period. Currently, we attempt to qualify all of our futures contracts for hedge accounting under the relevant derivative accounting guidance, but there can be no assurances that we will be successful in doing so. At December 31, 2010, all of our futures contracts qualified for hedge accounting. To the extent that all or some of our futures contracts do not qualify for hedge accounting, we could incur significant increases and decreases in our net income (loss) and stockholders' equity in the future based on fluctuations in the market value of our futures contracts from quarter to quarter. We had no derivative gains or losses related to our natural gas futures contracts for the years ended December 31, 2009 and 2010. Any negative fluctuations may cause our stock price to decline due to our failure to meet or exceed the expectations of securities analysts or investors.

Compliance with potential greenhouse gas regulations affecting our LNG plants or fueling stations may prove costly and negatively affect our financial performance.

California has adopted legislation, AB 32, which calls for a cap on greenhouse gas emissions throughout California and a statewide reduction to 1990 levels by 2020, and an additional 80% reduction below 1990 levels by 2050. Seven western U.S. states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces (British Columbia, Manitoba, Ontario and Quebec) formed the Western Climate Initiative to help combat climate change. Other states and the federal government are considering passing measures to regulate and reduce greenhouse gas emissions. Any of these regulations, when and if implemented, may regulate the greenhouse gas emissions produced by our LNG production plants in California and Texas or our LNG and CNG fueling stations and require that we obtain emissions credits or invest in costly emissions prevention technology. We cannot currently estimate the potential costs associated with federal or state regulation of greenhouse gas emissions from our LNG plants or LNG and CNG stations, and these unknown costs are not contemplated in the financial terms of our customer agreements. These unanticipated costs may have a negative impact on our financial performance and may impair our ability to fulfill customer contracts at an operating profit.

Natural gas fueling operations and vehicle conversions entail inherent safety and environmental risks that may result in substantial liability to us.

Natural gas fueling operations and vehicle conversions entail inherent risks, including equipment defects, malfunctions and failures and natural disasters, which could result in uncontrollable flows of natural gas, fires, explosions and other damages. For example, operation of LNG pumps requires special training and protective equipment because of the extreme low temperatures of LNG. LNG tanker trailers have also in the past been, and may in the future be, involved in accidents that result in explosions, fires and other damage. Improper refueling of LNG vehicles can result in venting of methane gas, which is a potent greenhouse gas, and LNG related methane emissions may in the future be regulated by the EPA or by state regulations. Additionally, CNG fuel tanks, if damaged or improperly maintained, may rupture and the contents of the tank may rapidly decompress and result in death or injury. In 2007, a driver of a CNG van in Los Angeles was killed when the previously damaged tank he was fueling ruptured. These risks may expose us to liability for personal injury, wrongful death, property damage, pollution and other environmental damage. We may incur substantial liability and cost if damages are not covered by insurance or are in excess of policy limits. If CNG or LNG vehicles are perceived to be unsafe, it will harm our growth and negatively affect BAF's ability to sell converted CNG vehicles, which would impair our financial performance.

Our business is heavily concentrated in the western United States, particularly in California and Arizona. Continuing economic downturns in these regions could adversely affect our business.

Our operations to date have been concentrated in California and Arizona. For the years ended December 31, 2008, 2009 and 2010, sales in California accounted for 44%, 49% and 49% respectively, and sales in Arizona accounted for 14%, 10% and 9%, respectively, of the total amount of gallons we delivered. A decline in the economy in these areas could slow the rate of adoption of natural gas vehicles, reduce fuel consumption or reduce the availability of government grants, any of which could negatively affect our growth.

We provide financing to fleet customers for natural gas vehicles, which exposes our business to credit risks.

We loan to certain qualifying customers a portion of, and occasionally up to 100%, of the purchase price of natural gas vehicles. We may also lease vehicles to customers in the future. There are risks associated with providing financing or leasing that could cause us to lose money. Some of these risks include: most of the equipment financed consists of vehicles, which are mobile and easily damaged, lost or stolen, there is a risk the borrower may default on payments, we may not be able to bill properly or track payments in adequate fashion to sustain growth of this service, and the amount of capital available to us is limited and may not allow us to make loans required by customers. Some of our customers, such as taxi owners, may depend on the CNG vehicles that we finance or lease to them as their sole source of income, which may make it difficult for us to recover the collateral in a bankruptcy proceeding. Any disruption in the credit markets may further reduce the amount of capital available to us and an economic recession or continued high unemployment rates may increase the rate of default by borrowers, leading to an increase in losses on our loan portfolio. As of December 31, 2010, we had $3.5 million outstanding in loans provided to customers to finance natural gas vehicle purchases.

Our business is subject to a variety of governmental regulations that may restrict our business and may result in costs and penalties.

We are subject to a variety of federal, state and local laws and regulations relating to the environment, health and safety, labor and employment and taxation, among others. These laws and regulations are complex, change frequently and have tended to become more stringent over time. Failure to comply with these laws and regulations may result in a variety of administrative, civil and criminal enforcement measures, including assessment of monetary penalties and the imposition of remedial requirements. From time to time, as part of the regular overall evaluation of our operations, including newly acquired operations, we may be subject to compliance audits by regulatory authorities. In addition, any failure to comply with regulations related to the government procurement process at the federal, state or local level or restrictions on political activities and lobbying may result in administrative or financial penalties including being barred from providing services to governmental entities, which accounted for approximately 53% of our yearly revenues from 2006 through 2010.

In connection with our LNG liquefaction activities and the landfill gas processing facility operated by DCE, we need or may need to apply for additional facility permits or licenses to address storm water or wastewater discharges, waste handling, and air emissions related to production activities or equipment operations. This may subject us to permitting conditions that may be onerous or costly. Compliance with laws and regulations and enforcement policies by regulatory agencies could require us to make material expenditures and may distract our officers, directors and employees from the operation of our business.

We may not be successful in developing or expanding our biomethane, or renewable natural gas, business.

In November, 2010, we announced that we have entered into an agreement to develop a pipeline quality biomethane project at a Republic Services owned landfill outside of Detroit, Michigan. We are also in the process of expanding our operations at our biomethane production facility at the McCommas Bluff landfill outside of Dallas, Texas. Biomethane production represents a new area of investment and operations for us, and we may not be successful in developing these projects and generating a financial return from our investment. Historically, projects that produce pipeline quality biomethane, or renewable natural gas, have often failed due to the volatile prices of conventional natural gas, unpredictable biomethane production levels and technological difficulties and costs associated with operating the production facilities. Our ability to succeed in expanding our McCommas Bluff project and developing our project in Michigan depends on our ability to successfully manage the construction and operation of biomethane production facilities and our ability to sell and market the biomethane at substantial premiums to recent conventional natural gas prices. If we are unsuccessful in managing the construction and operation of our biomethane production facilities, our business and financial results would be materially and adversely affected. In the absence of state and federal programs that support premium prices for renewable natural gas, we will be unable to generate profit and financial return from these investments, and our financial results could be materially and adversely affected.

Operational issues, permitting and other factors at DCE's landfill gas processing facility may adversely affect both DCE's ability to supply biomethane and our operating results.

In August 2008, we acquired our 70% interest in DCE. In April 2009, DCE entered into a 15-year gas sale agreement with Shell Energy North America (US) L.P. ("Shell") for the sale to Shell of specified levels of biomethane produced by DCE's landfill gas processing facility. There is, however, no guarantee that DCE will be able to produce or sell up to the maximum volumes called for under the agreement. DCE's ability to produce such volumes of biomethane depends on a number of factors beyond DCE's control, including, but not limited to, the availability and composition of the landfill gas that is collected, successful permitting, the operation of the landfill by the City of Dallas and the reliability of the processing facility's critical equipment. The DCE facility is subject to periods of reduced production or non-production due to upgrades, maintenance, repairs and other factors. For example, as part of an operational upgrade in March 2009, the facility was shut down for approximately one month. Also, on June 12, 2009, the facility was taken offline for repairs that were completed on July 2, 2009 and the facility was taken offline for upgrades from September 20, 2010 until September 25, 2010. Severe winter weather in Texas resulted in power outages and broken equipment in February 2011, resulting in a week of down time and an extended period during which the plant operated at half capacity. Future operational upgrades, including planned expansion of the plant, or complications in the operations of the facility could require additional shutdowns during 2011, and accordingly, DCE's revenues may fluctuate from quarter to quarter.

Our quarterly results of operations have not been predictable in the past and have fluctuated significantly and may not be predictable and may fluctuate in the future.

Our quarterly results of operations have historically experienced significant fluctuations. Our net losses (income) were approximately $5.4 million, $3.2 million, $12.1 million, $23.7 million, $6.5 million, $6.4 million, $18.5 million, $1.9 million, $24.4 million, $(9.9) million, $1.8 million, and $(13.8) million for the three months ended March 31, 2008, June 30, 2008, September 30, 2008, December 31, 2008, March 31, 2009, June 30, 2009, September 30, 2009, December 31, 2009, March 31, 2010, June 30, 2010, September 30, 2010, and December 31, 2010, respectively. Our quarterly results may fluctuate significantly as a result of a variety of factors, many of which are beyond our control. In particular, if our stock price increases or decreases in future periods during which our Series I warrants are outstanding, we will be required to recognize corresponding losses or gains related to the valuation of the Series I warrants that could materially impact our results of operations. If our quarterly results of operations fall below the expectations of securities analysts or investors, the price of our common stock could decline substantially. Fluctuations in our quarterly results of operations may be due to a number of factors, including, but not limited to, our ability to increase sales to existing customers and attract new customers, the addition or loss of large customers, construction cost overruns, downtime at our facilities (including any shutdowns of DCE's landfill gas processing facility), the amount and timing of operating costs, unanticipated expenses, capital expenditures related to the maintenance and expansion of our business, operations and infrastructure, changes in the price of natural gas, changes in the prices of CNG and LNG relative to gasoline and diesel, changes in our pricing policies or those of our competitors, fluctuation in the value of our outstanding Series I warrants or natural gas futures contracts, the costs related to the acquisition of assets or businesses, regulatory changes, and geopolitical events such as war, threat of war or terrorist actions. Investors in our stock should not rely on the results of one quarter as an indication of future performance as our quarterly revenues and results of operations may vary significantly in the future. Therefore, period-to-period comparisons of our operating results may not be meaningful.

The future price of our common stock or the offering price of our common stock in future offerings could result in a reduction of the exercise price of our Series I warrants and result in dilution of our common stock.

We issued Series I warrants to purchase up to 3,314,394 shares of our common stock in connection with our registered direct offering completed in November 2008. 2,130,682 of these Series I warrants remain outstanding as of December 31, 2010. These warrants contain provisions that require an adjustment in the exercise price of the Series I warrants in the event that we price any offering of common stock at a price below the current exercise price, which is $12.68 per share.

Sales of outstanding shares of our stock into the market in the future could cause the market price of our stock to drop significantly, even if our business is doing well.

If our stockholders sell, or indicate an intention to sell, substantial amounts of our common stock in the public market, the trading price of our common stock could decline. As of December 31, 2010, 69,610,098 shares of our common stock were outstanding. The 11,500,000 shares sold in our initial public offering, the 4,419,192 shares of common stock and the 2,130,682 shares of common stock subject to outstanding warrants sold in our registered direct offering that closed on November 3, 2008, the 9,430,000 shares of our common stock sold in our common stock offering that closed July 1, 2009 and the 3,450,000 shares of our common stock sold in our common stock offering that closed November 11, 2010 are freely tradable without restriction or further registration under federal securities laws unless purchased by our affiliates.

In addition, upon the closing of our acquisition of IMW, we issued 4,017,408 shares of our common stock, which are registered for immediate resale. We issued an additional 601,926 shares to the IMW shareholder in January 2011. IMW's shareholder had sold 1,908,468 shares of our common stock as of December 31, 2010.

Shares held by non-affiliates for more than six months may generally be sold without restriction, other than a current public information requirement, and may be sold freely without any restrictions after one year. All other outstanding shares of common stock may be sold under Rule 144 under the Securities Act, subject to applicable restrictions.

In addition, as of December 31, 2010, there were 10,433,551 shares underlying outstanding options and 17,130,682 shares underlying outstanding warrants (including the 2,130,682 Series I warrant shares sold in our registered direct offering which closed on November 3, 2008). All shares subject to outstanding options and warrants are eligible for sale in the public market to the extent permitted by the provisions of various option and warrant agreements and Rule 144, or have been registered under the Securities Act of 1933, as amended. If these additional shares are sold, or if it is perceived that they will be sold in the public market, the trading price of our stock could decline.

Further, as of December 31, 2010, 16,539,720 shares of our stock held by our co-founder and board member T. Boone Pickens are subject to pledge agreements with banks. Should one or more of the banks be forced to sell the shares subject to the pledge, the trading price of our stock could also decline. In addition, a number of our directors and executive officers have entered into Rule 10b5-1 Sales Plans with a broker to sell shares of our common stock that they hold or that may be acquired upon the exercise of stock options. Sales under these plans will occur automatically without further action by the director or officer once the price and/or date parameters of the selling plan are achieved. As of December 31, 2010, 1,851,765 shares in the aggregate were subject to future sale by our named executive officers and directors under these selling plans. All sales of common stock under the plans will be reported through appropriate filings with the SEC.

A significant portion of our stock is beneficially owned by a single stockholder whose interests may differ from yours and who will be able to exert significant influence over our corporate decisions, including a change of control.

As of December 31, 2010, Boone Pickens and affiliates (including Madeleine Pickens, his wife) owned in the aggregate 28% of our outstanding shares of common stock and beneficially owned in the aggregate approximately 41% of the outstanding shares of our common stock, inclusive of the 15,000,000 shares underlying a warrant held by Mr. Pickens. As a result, Mr. Pickens will be able to influence or control matters requiring approval by our stockholders, including the election of directors and the approval of mergers, acquisitions or other extraordinary transactions. Mr. Pickens may have interests that differ from yours and may vote in a way with which you disagree and which may be adverse to your interests. This concentration of ownership may have the effect of delaying, preventing or deterring a change of control of our company, could deprive our stockholders of an opportunity to receive a premium for their stock as part of a sale of our company, and might ultimately affect the market price of our stock. Conversely, this concentration may facilitate a change in control at a time when you and other investors may prefer not to sell.

Item 1B. Unresolved Staff Comments.

We have not received written comments from the SEC staff more than 180 days before the end of our 2010 fiscal year.

Item 2. Properties.

Our corporate headquarters are located at 3020 Old Ranch Parkway, Suite 400, Seal Beach, CA 90740, where we occupy approximately 30,000 square feet. Our office lease expires on January 31, 2015. We believe our existing facilities are adequate for our current and near term operating needs.

The BAF Technologies Inc. headquarters is located in Dallas, TX, where they occupy approximately 82,000 square feet. The lease expires April 30, 2012.

We own and operate the Pickens Plant located in Willis, Texas, approximately 50 miles north of Houston. We own approximately 24 acres on which the plant is situated, along with approximately 34 acres surrounding the plant.

We own an LNG liquefaction plant in Boron, California, approximately 125 miles from Los Angeles. In November 2006, we entered into a ground lease for the 36 acres on which this plant is situated. The lease is for an initial term of 30 years, beginning on the date that the plant commences full operations, and requires annual base rent payments of $230,000 per year, plus up to $130,000 per year for each 30,000,000 gallons of production capacity utilized, subject to future adjustment based on consumer price index changes. We began paying rent on December 1, 2008. For 2010, we recorded rent expense of approximately $1.5 million, which included royalty payments to the landlord for each gallon of LNG produced at the facility as well as for certain other services that the landlord provided.

We lease or license the land upon which we construct, operate and maintain some of our CNG and LNG fueling stations for our customers. We often own the equipment and fixtures that comprise the CNG fueling stations, and in some cases, LNG stations. The ground leases or licenses for our stations typically have a term of 10 years and require payments of a fixed amount or a variable amount based on the number of gallons sold at the site during the period.

We lease a manufacturing facility in Chilliwack, British Columbia where we occupy approximately 50,000 square feet. The facility lease expires in January 2018. We also lease a warehouse location in Chilliwack, British Columbia consisting of approximately 15,000 square feet that expires in October 2011.

We also lease two facilities in Taicang, China where we occupy approximately 32,000 square feet and 31,000 square feet. These leases expire in August 2012 and December 2013, respectively. We also lease an office in Shanghai, China where we occupy approximately 7,000 square feet. This lease expires in December 2012.

In Bangladesh, we occupy five office and warehouse spaces in various locations totaling approximately 7,000 square feet in the aggregate. The lease terms expire between January 2012 and July 2013.

We also occupy several smaller locations in Colombia, with leased space totaling approximately 19,000 square feet in the aggregate. The leases expire at various dates through January 2012.

Item 3. Legal Proceedings.

We are party to various legal actions that have arisen in the ordinary course of our business. During the course of our operations, we are also subject to audit by tax authorities for varying periods in various federal, state, local, and foreign tax jurisdictions. Disputes have and may continue to arise during the course of such audits as to facts and matters of law. It is impossible at this time to determine the ultimate liabilities that we may incur resulting from any lawsuits, claims and proceedings, audits, commitments, contingencies and related matters or the timing of these liabilities, if any. If these matters were to be ultimately resolved unfavorably, an outcome not currently anticipated, it is possible that such outcome could have a material adverse effect upon our consolidated financial position or results of operations. However, we believe that the ultimate resolution of such actions will not have a material adverse effect on our consolidated financial position, results of operations, or liquidity.

Item 4. (Removed and Reserved)

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Market Information

Our common stock has been quoted on the Nasdaq Global Market under the symbol "CLNE" since May 25, 2007. Prior to that time, there was no public market for our stock. Set forth below are the high and low sales prices as reported by Nasdaq for our common stock for the periods indicated.

	Sales Prices	
	High	Low
Fiscal Year 2009		
First Quarter 2009	$ 7.61	$ 4.62
Second Quarter 2009	$10.25	$ 5.89
Third Quarter 2009	$15.18	$ 7.81
Fourth Quarter 2009	$16.57	$10.95
Fiscal Year 2010		
First Quarter 2010	$23.70	$15.15
Second Quarter 2010	$23.65	$13.48
Third Quarter 2010	$19.36	$13.95
Fourth Quarter 2010	$15.80	$13.14

Holders

There were approximately 63 stockholders of record as of March 7, 2011. We believe there are approximately 52,679 stockholders of our common stock held in street name.

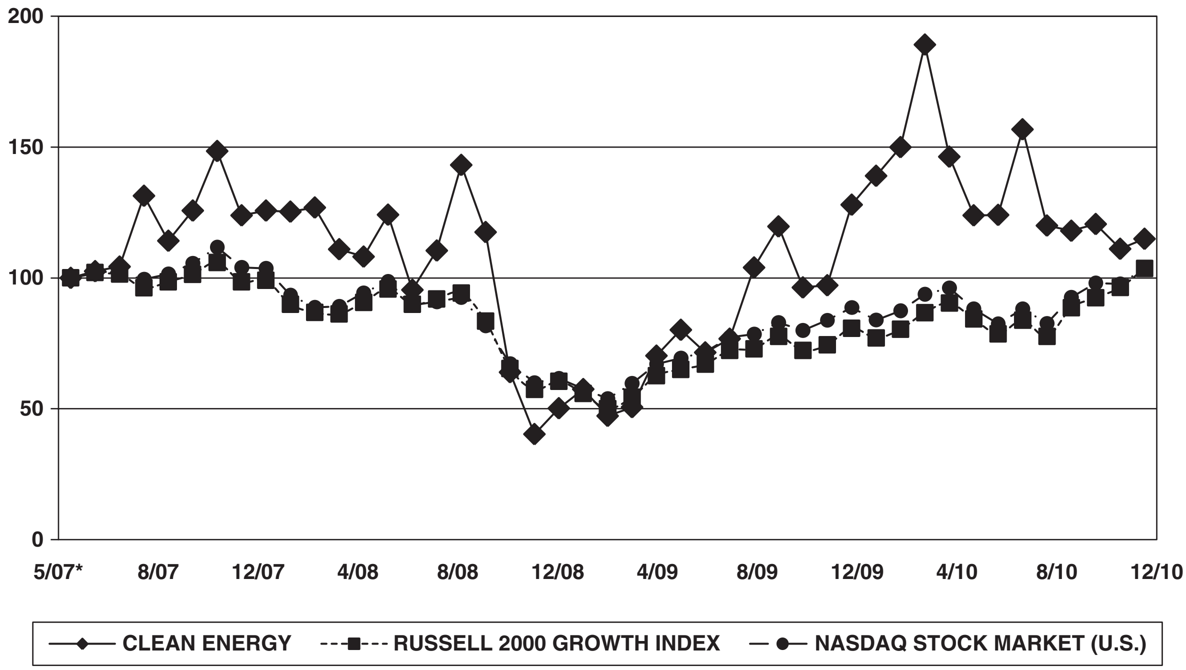
Dividend Policy

We have not paid any dividends to date and do not anticipate paying any dividends on our common stock in the foreseeable future. We anticipate that all future earnings will be retained to finance future growth.

Performance Graph

This performance graph shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), or incorporated by reference into any filing of Clean Energy Fuels Corp. under the Securities Act, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

The following graph shows a comparison from May 25, 2007 (the date our common stock commenced trading on The Nasdaq Global Market) through December 31, 2010 of the cumulative total return for our common stock, the Nasdaq Global Market Index, and the Russell 2000 Growth Index. We chose to include the Russell 2000 Growth Index as a comparable index due to the lack of a comparable industry index or peer group. We are the only actively traded public company whose only line of business is to sell natural gas and the associated equipment and services necessary to use natural gas as a vehicle fuel. Such returns are based on historical results and are not intended to suggest future performance. Data for the Nasdaq Global Market Index and the Russell 2000 Growth Index assumes reinvestment of dividends.



* Assumes $100 was invested on May 25, 2007 in our common stock, the Nasdaq Global Market Index, and the Russell 2000 Growth Index. The Nasdaq Global Market Index and the Russell 2000 Growth Index results include reinvestment of dividends.

Item 6. Selected Financial Data.

You should read the following selected historical consolidated financial data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and the notes elsewhere in this Form 10-K.

The consolidated statements of operations data for the years ended December 31, 2008, 2009, and 2010 and the consolidated balance sheet data at December 31, 2009, and 2010, are derived from our audited consolidated financial statements in this Form 10-K. The consolidated statements of operations data for the years ended December 31, 2006 and 2007, and the consolidated balance sheet data at December 31, 2006, 2007, and 2008 are derived from our audited consolidated financial statements that are not included in this Form 10-K. The historical results are not necessarily indicative of the results to be expected in any future period.

(In thousands, except share data)

	Year Ended December 31,				
	2006	2007	2008	2009	2010
Statement of Operations Data:					
Total Revenues(1)	$ 91,547	$ 117,716	$ 125,867	$ 131,503	$ 211,834
Operating expenses:					
Costs of sales	74,048	85,660	98,768	82,921	141,889
Derivative (gains) losses(2):					
Futures contracts	78,995	—	611	—	—
Series I warrant valuation	—	—	—	17,367	(10,278)
Loss on extinguishment of derivative liability	2,142	—	—	—	—
Selling, general and administrative(3)	20,860	35,934	62,416	47,509	63,258
Depreciation and amortization	5,765	7,108	9,624	16,992	22,487
Total operating expenses:	181,810	128,702	171,419	164,789	217,356
Operating income (loss)	(90,263)	(10,986)	(45,552)	(33,286)	(5,522)
Interest income (expense), net	746	3,506	1,630	(32)	(1,194)
Other (expense), net	(255)	(192)	(168)	(310)	2,080
Equity in gains (losses) of equity method investee	—	—	(188)	244	427
Income (loss) before income taxes	(89,772)	(7,672)	(44,278)	(33,384)	(4,209)
Income tax (expense) benefit	12,271	(1,222)	(290)	(304)	1,436
Net income	(77,501)	(8,894)	(44,568)	(33,688)	(2,773)
Minority interest in net income	—	—	105	439	257
Net loss attributable to Clean Energy Fuels Corp	$ (77,501)	$ (8,894)	$ (44,463)	$ (33,249)	$ (2,516)
Basic and diluted loss per share	$ (2.45)	$ (0.22)	$ (0.98)	$ (0.60)	$ (0.04)
Weighted average common share outstanding:					
Basic and diluted	31,676,399	40,258,440	45,367,991	55,021,961	62,549,311

(1) Revenues include the following amounts:

	Year Ended December 31,				
	2006	2007	2008	2009	2010
Fuel tax credits (VETC)	$3,810	$17,046	$17,197	$15,535	$16,042

(2) 2006 amount includes $78.7 million of losses on certain derivative contracts. The contracts were assumed by our largest stockholder, Boone Pickens, on December 28, 2006.

(3) 2008 amount includes $18.6 million of expenses to support Proposition 10 on the California ballot in November 2008. 2010 amount includes $2.2 million of impairment charges.

	December 31,				
	2006	2007	2008	2009	2010
Balance Sheet Data:					
Cash and cash equivalents	$ 937	$ 67,938	$ 36,284	$ 67,087	$ 55,194
Restricted cash	—	—	2,500	2,500	2,500
Short-term investments	—	12,480	—	—	—
Working capital	44,811	119,481	47,338	78,799	65,070
Total assets	136,933	249,025	290,374	355,799	583,499
Long-term debt, inclusive of current portion	282	225	25,084	12,221	64,416
Stockholders' equity	122,916	230,932	233,777	277,189	413,287

	Year Ended December 31,		
	2008	2009	2010
Key Operating Data:			
Gasoline gallon equivalents delivered (in millions):			
CNG	47.6	67.9	81.4
Biomethane	2.0	6.4	7.4
LNG	23.9	26.7	33.9
Total	73.5	101.0	122.7

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The discussion in this section contains forward-looking statements. These statements relate to future events or our future financial performance. We have attempted to identify forward-looking statements by terminology such as "anticipate," "believe," "can," "continue," "could," "estimate," "expect," "intend," "may," "plan," "potential," "predict," "should," "would" or "will" or the negative of these terms or other comparable terminology, but their absence does not mean that a statement is not forward-looking. These statements are only predictions and involve known and unknown risks, uncertainties and other factors, which could cause our actual results to differ from those projected in any forward-looking statements we make. See "Risk Factors" in Part I, Item 1A of this report for a discussion of some of these risks and uncertainties. This discussion should be read with our financial statements and related notes included elsewhere in this report.

We provide natural gas solutions for vehicle fleets primarily in the United States and Canada. Our primary business activity is selling CNG and LNG vehicle fuel to our customers. We also build, operate and maintain fueling stations, manufacture and service advanced natural gas fueling compressors, and related equipment, process and sell renewable biomethane and provide natural gas vehicle conversions. Our customers include fleet operators in a variety of markets, such as public transit, refuse hauling, airports, taxis and regional trucking. In April 2008, we opened our first CNG station in Lima, Peru, through our joint venture, Clean Energy del Peru. In August 2008, we acquired 70% of the outstanding membership interests of DCE. DCE owns a facility that collects, processes and sells renewable biomethane at the McCommas Bluff landfill in Dallas, Texas. On October 1, 2009, we acquired 100% of BAF Technologies, Inc. ("BAF"), a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles. On September 7, 2010, we completed the purchase of IMW, a company that manufactures and services advanced, non-lubricated natural gas fueling compressor and related equipment. On December 15, 2010, we acquired Northstar, who provides design, engineering, construction and maintenance services for LNG and LCNG fueling stations.

Overview

This overview discusses matters on which our management primarily focuses in evaluating our financial condition and operating performance.

Sources of revenue. We generate the vast majority of our revenue from selling CNG and LNG and providing operations and maintenance services to our customers. The balance of our revenue is provided by designing and constructing natural gas fueling stations, financing our customers' natural gas vehicle purchases, sales of pipeline quality biomethane produced by our DCE joint venture, sales of natural gas vehicles through our wholly owned subsidiary BAF, and commencing on September 7, 2010, sales of advanced natural gas fueling compressors and related equipment and maintenance services through IMW. In addition, on December 15, 2010, we began generating revenue from LNG and LCNG fueling station design, engineering, construction and maintenance services through Northstar.

Key operating data. In evaluating our operating performance, our management focuses primarily on: (1) the amount of CNG and LNG gasoline gallon equivalents delivered (which we define as (i) the volume of gasoline gallon equivalents we sell to our customers, plus (ii) the volume of gasoline gallon equivalents dispensed to our customers at stations where we provide operating and maintenance ("O&M") services but do not directly sell the CNG or LNG, plus (iii) our proportionate share of the gasoline gallon equivalents sold as CNG by our joint venture in Peru, plus (iv) our proportionate share of the gasoline gallon equivalents of biomethane produced and sold as pipeline quality natural gas by DCE), (2) our gross margin (which we define as revenue minus cost of sales), and (3) net income (loss). The following table, which you should read in conjunction with our consolidated financial statements and notes contained elsewhere in this Form 10-K, presents our key operating data for the years ended December 31, 2008, 2009, and 2010:

Gasoline gallon equivalents delivered

	Year Ended December 31,		
(in millions)	**2008**	**2009**	**2010**
CNG	47.6	67.9	81.4
Biomethane	2.0	6.4	7.4
LNG	23.9	26.7	33.9
Total	73.5	101.0	122.7
Operating data			
Gross margin	$ 27,099	$ 48,582	$69,945
Net loss	(44,463)	(33,249)	(2,516)

Key trends in 2008, 2009 and 2010. According to the U.S. Energy Information Administration, demand for natural gas fuels in the United States increased by approximately 26% during the period January 1, 2008 through December 31, 2010. We believe this growth in demand was attributable primarily to the rising prices of gasoline and diesel relative to CNG and LNG during these periods and increasingly stringent environmental regulations affecting vehicle fleets.

The number of fueling stations we served grew from 147 at December 31, 2004 to 224 at December 31, 2010 (a 52.4% increase). Included in this number are all of the CNG and LNG fueling stations we own, maintain or with which we have a fueling supply contract. The amount of CNG and LNG gasoline gallon equivalents we delivered from 2005 to 2010 increased by 116%. The increase in gasoline gallon equivalents delivered was the primary contributor to increased revenues during these periods. Our cost of sales also increased during these periods, which was attributable primarily to increased costs related to delivering more CNG and LNG to our customers.

During the last half of 2009 and the twelve months of 2010, we also experienced reduced margins in certain markets, particularly in the municipal transit and refuse sector. The reduction in margins is primarily a result of increased competition and sales agreements with larger entities that have greater pricing leverage. Also, in many cases, our agreements with our customers, including governmental agencies, are subject to a competitive bidding process and we may be required to reduce our prices to maintain our contracts as they come up for bid. We also have significant contracts with government entities that are experiencing large budget deficits and these customers have and may continue to demand price reductions for our services. In addition, in May and June of 2009, we acquired four compressed natural gas operations and maintenance services contracts with municipal transit agencies and in 2010 we won two contracts with a transit agency in California that have significant volume but smaller margins than we typically generate on our fuel sales. As a result, the overall average margin on our fuel sales across our business decreased during these periods.

We believe that our margins on fuel sales will improve in the future to the extent we are successful in increasing our retail CNG and LNG fueling operations, which is where we earn our highest margin, relative to our lower margin operations, such as municipal transit. If we are unsuccessful in growing our retail CNG and LNG fueling operations, we may experience reduced margins. We may also lose contracts with governmental customers if we are unwilling or unable to reduce our prices or lose in the competitive bidding process, which would reduce our volumes. For example, MTS of San Diego, which represented approximately 6.0 million gasoline gallon equivalents of our CNG volume in 2009, conducted a competitive bidding procurement and awarded the contract to a competitor beginning July 27, 2010. The Washington Metropolitan Area Transit Authority, which represented approximately 6.3 million gallons of CNG in 2010, also conducted a competitive bidding procurement which resulted in the award of the contract to a competitor on December 31, 2010. We will need to increase our business with non-government entities to replace volumes lost in competitive bid procurements when we are not successful in retaining the contracts.

During 2010, prices for oil, gasoline, diesel fuel and natural gas generally increased. Oil increased from a low of $72.89 per barrel on January 30, 2010 to a price of $91.38 per barrel on December 31, 2010. In California, average retail prices for gasoline have increased from a low of $2.97 per gallon in February 2010 to $3.33 per gallon at December 31, 2010, and average retail prices for diesel fuel have increased from a low of $2.90 per diesel gallon in February 2010 to $3.47 per diesel gallon at December 31, 2010. Higher gasoline and diesel prices improve our margins on fuel sales to the extent we price fuel at a discount to gasoline or diesel. During this time period, the price for natural gas remained fairly consistent. The NYMEX price for natural gas ranged from a low of $3.29 per MMbtu in November 2010 to $4.27 per MMbtu at December 31, 2010. The average retail sales price of our CNG fuel sold in the Los Angeles metropolitan area ranged from $2.50 for the month of January 2010 to $2.60 for the month of December 2010.

Recent developments. On September 7, 2010, the Company, acting through certain of its subsidiaries, completed its purchase of IMW. IMW manufactures and services advanced natural gas fueling compressors and related equipment for the global natural gas fueling market. IMW is headquartered near Vancouver, British Columbia, has a second manufacturing facility near Shanghai, China and has sales and service offices in Bangladesh, Columbia and the United States. We believe the acquisition of IMW will enable us to participate in the growth of natural gas vehicle fueling overseas, as well as in North America, and enable us to offer our customers a wider variety of natural gas vehicle fueling solutions.

On December 15, 2010, we acquired Northstar under a stock purchase agreement. Northstar is a leading provider of design, engineering, construction and maintenance services for LNG and LCNG fueling stations.

On February 17, 2011, we invested an additional $1.6 million in the Vehicle Production Group, LLC. At March 10, 2011, we have invested $12.0 million in VPG.

On February 25, 2011 (the "Closing Date"), we paid $1.2 million for a 19.9% interest in ServoTech Engineering, Inc. ("ServoTech"), a company who provides design and engineering services for natural gas fueling systems among other services. We also have an option to purchase the remaining 81.1% of ServoTech for $2.8 million over the 15 month period following the Closing Date.

Anticipated future trends. We anticipate that, over the long term, the prices for gasoline and diesel will continue to be higher than the price of natural gas as a vehicle fuel, and more stringent emissions requirements will continue to make natural gas vehicles an attractive alternative to traditional gasoline and diesel powered vehicles. Our belief that natural gas will continue, over the long term, to be a cheaper vehicle fuel than gasoline or diesel is based in part on the growth in U.S. natural gas production. A 2008 Navigant Consulting, Inc. study indicates that as a result of new unconventional gas shale discoveries from 22 basins in the U.S., maximum estimates of total recoverable domestic reserves from producers have increased to equal 118 years of U.S. production at 2007 production levels. The study indicated a mean level of reserves equal to 88 years of supply at 2007 production levels. According to the report, shale gas production growth from only the major six shale resources in the U.S., plus the Marcellus shale, could become 27 billion cubic feet per day and as high as 39 billion cubic feet per day by 2015. Navigant has also indicated that development of the shale resources base has resulted in a substantial surplus of natural gas compared to demand of as much as 11 billion cubic feet per day. These current surplus levels are 18% of annual average historical U.S. consumption levels of approximately 20 Tcf per year; providing sufficient gas supply to meet the requirements of all existing markets and to meet new market requirements. Based on analyst reports, we believe that there is a significant worldwide supply of natural gas relative to crude oil as well. According to the 2010 BP Statistical Review of World Energy, on a global basis, the ratio of proven natural gas reserves to 2009 natural gas production was 37% greater than the ratio of proven crude oil reserves to 2009 crude oil production. This analysis suggests significantly greater long term availability of natural gas than crude oil based on current consumption.

We believe there will be significant growth in the consumption of natural gas as a vehicle fuel among vehicle fleets, and our goal is to capitalize on this trend and enhance our leadership position as this market expands. With our recent acquisitions of IMW and Northstar, we are now a fully integrated provider of advanced compression technology, station-building and fueling. We have built natural gas fueling stations, and plan to build additional natural gas fueling stations, that will provide LNG to fleet vehicles at the Ports of Los Angeles and Long Beach and for other regional corridors throughout the United States. We also anticipate expanding our sales of CNG and LNG in the other markets in which we operate, including regional trucking, refuse hauling, airports and public transits. Consistent with the anticipated growth of our business, we also expect that our operating costs and capital expenditures will increase, primarily from the anticipated expansion of our station network or LNG production capacity, as well as the logistics of delivering more CNG and LNG to our customers. We also anticipate that we will continue to seek to acquire assets and/or businesses that are in the natural gas fueling infrastructure or biomethane production business that may require us to raise additional capital. Additionally, we have and will continue to increase our sales and marketing team and other necessary personnel as we seek to expand our existing markets and enter new markets, which will also result in increased costs.

Continuing high unemployment rates and reduced economic activity may reduce our opportunities to attract new fleet customers. Many governmental entities, which represented approximately 53% of our revenues from 2006 through 2010, are experiencing significant budget deficits as a result of the economic recession and have been, and may continue to be, unable to invest in new natural gas vehicles for their transit or refuse fleets or may be compelled to reduce public transportation and services, or the prices they pay for these services, which would negatively affect our business.

Sources of liquidity and anticipated capital expenditures. Liquidity is the ability to meet present and future financial obligations either through operating cash flows, the sale or maturity of existing assets, or by the acquisition of additional funds through capital management. Historically, our principal sources of liquidity have consisted of cash provided by operations and financing activities.

Our business plan calls for approximately $80.7 million in capital expenditures in 2011, primarily related to construction of new fueling stations. We may also elect to invest additional amounts in expansion of our California LNG plant, expansion of our DCE landfill gas processing plant, or for other acquisitions or investments in companies or assets in the natural gas fueling infrastructure, services and production industries, including biomethane production. We will need to raise additional capital as necessary to fund any expansion of our California LNG plant or DCE landfill gas plant, acquisitions or other capital expenditures or investments that we cannot fund through available cash, our line of credit from PCB, or cash generated by operations. The timing and necessity of any future capital raise will depend on our rate of new station construction, which may be affected by any federal legislation that provides incentives for natural gas vehicle purchases and fuel use, any decision to expand our California LNG plant or DCE gas processing plant and potential merger or acquisition activity. For more information, see "Liquidity and Capital Resources" below. We may not be able to raise capital on terms that are favorable to existing stockholders or at all. Any inability to raise capital may impair our ability to invest in new stations, expand our California LNG plant or DCE gas processing plant, develop natural gas fueling infrastructure and invest in strategic transactions or acquisitions and reduce our ability to grow our business and generate increased revenues.

Business risks and uncertainties. Our business and prospects are exposed to numerous risks and uncertainties. For more information, see "Risk Factors" in Part I, Item 1A.

Operations

We generate revenues principally by selling CNG and LNG and providing O&M services to our vehicle fleet customers. For the year ended December 31, 2010, CNG and biomethane (together) represented 72% and LNG represented 28% of our natural gas sales (on a gasoline gallon equivalent basis). To a lesser extent, we generate revenues by designing and constructing fueling stations and selling or leasing those stations to our customers. We also generate material revenues through sales of biomethane produced by our joint venture subsidiary DCE, sales of natural gas vehicles by our wholly owned subsidiary BAF, sales of advanced natural gas fueling compressors and related equipment and maintenance services through IMW (since September 7, 2010), and commencing on December 15, 2010, sales of LNG and LCNG fueling station design, construction and O&M services through Northstar. Substantially all of our operating and maintenance revenues are generated from CNG stations, as owners of LNG stations tend to operate and maintain their own stations. Substantially all of our station sale and leasing revenues have been generated from CNG stations.

CNG Sales

We sell CNG through fueling stations located on our customers' properties and through our network of public access fueling stations. At these CNG fueling stations, we procure natural gas from local utilities or brokers under standard, floating-rate arrangements and then compress and dispense it into our customers' vehicles. Our CNG sales are made primarily through contracts with our fleet customers. Under these contracts, pricing is determined primarily on an index-plus basis, which is calculated by adding a margin to the local index or utility price for natural gas. CNG sales revenues based on an index-plus methodology increase or decrease as a result of an increase or decrease in the price of natural gas. We also sell a small amount of CNG under fixed-price contracts. We will continue to offer fixed price contracts, as appropriate, and consistent with our natural gas hedging policy that was revised in May 2008. Our fleet customers typically are billed monthly based on the volume of CNG sold at a station. The remainder of our CNG sales are on a per fill-up basis at prices we set at the pump based on prevailing market conditions. These customers typically pay using a credit card at the station.

LNG Sales

We sell substantially all of our LNG to fleet customers, who typically own and operate their fueling stations. We also sell LNG to customers at our five public LNG stations and for non-vehicle use. During 2010, we procured 28% of our LNG from third-party producers, and we produced the remainder of the LNG at our liquefaction plants in Texas and California. For LNG that we purchase from third parties, we may enter into "take or pay" contracts that require us to purchase minimum volumes of LNG at index-based rates. We deliver LNG via our fleet of 58 tanker trailers to fueling stations, where it is stored and dispensed in liquid form into vehicles. We sell LNG principally through supply contracts that are priced on either a fixed-price or index-plus basis. LNG sales revenues based on an index-plus methodology increase or decrease as a result of an increase or decrease in the price of natural gas. We also provided price caps to certain customers on the index component of their index-plus pricing arrangement for certain contracts we entered into on or prior to December 31, 2006. Effective January 1, 2007, we ceased offering price-cap contracts to our customers, but we will continue to perform our obligations under price-cap contracts we entered into before January 1, 2007. We will continue to offer fixed price contracts as appropriate and consistent with our natural gas hedging policy adopted in May 2008. Our LNG contracts provide that we charge our customers periodically based on the volume of LNG supplied.

Government Incentives

From October 1, 2006 through December 31, 2010, we received a federal fuel tax credit ("VETC") of $0.50 per gasoline gallon equivalent of CNG and $0.50 per liquid gallon of LNG that we sold as vehicle fuel. Based on the service relationship with our customers, either we or our customers were able to claim the credit. We recorded these tax credits as revenues in our consolidated statements of operations as the credits are fully refundable and do not need to offset tax liabilities to be received. As such, the credits are not deemed income tax credits under the accounting guidance applicable to income taxes. In addition, we believe the credits are properly recorded as revenue because we often incorporate the tax credits into our pricing with our customers, thereby lowering the actual price per gallon we charge them. The program providing for the VETC expires on December 31, 2011.

Operation and Maintenance

We generate a portion of our revenue from operation and maintenance agreements for CNG fueling stations where we do not supply the fuel. We refer to this portion of our business as "O&M." At these fueling stations, the customer contracts directly with a local broker or utility to purchase natural gas. For O&M services, we do not sell the fuel itself, but generally charge a per-gallon fee based on the volume of fuel dispensed at the station. We include the volume of fuel dispensed at the stations at which we provide O&M services in our calculation of aggregate gasoline gallon equivalents sold.

Station Construction

We generate a small portion of our revenue from designing and constructing fueling stations and selling or leasing the stations to our customers. For these projects, we act as general contractor or supervise qualified third-party contractors. We charge construction fees or lease rates based on the size and complexity of the project.

On December 15, 2010, we completed the purchase of Northstar, an entity that provides design, engineering, construction and maintenance services for LNG and LCNG fueling stations. Since the December 15, 2010 acquisition date, Northstar contributed approximately $0.7 million to our revenue.

Vehicle Acquisition and Finance

In 2006, we commenced offering vehicle finance services for some of our customers' purchases of natural gas vehicles or the conversion of their existing gasoline or diesel powered vehicles to operate on natural gas. We loan to certain qualifying customers a portion of, and on occasion up to 100%, of the purchase price of their natural gas vehicles. We may also lease vehicles in the future. Where appropriate, we apply for and receive state and federal incentives associated with natural gas vehicle purchases and pass these benefits through to our customers. We may also secure vehicles to place with customers or pay deposits with respect to such vehicles prior to receiving a firm order from our customers, which we may be required to purchase if our customer fails to purchase the vehicle as anticipated. Through December 31, 2010, we have not generated significant revenue from vehicle finance activities.

Landfill Gas

In August 2008, we acquired 70% of the outstanding membership interests of DCE for a purchase price of $19.6 million including transaction costs. DCE owns a facility that collects, processes and sells biomethane from the McCommas Bluff landfill located in Dallas, Texas. From the acquisition date through December 31, 2008, and for the years ended December 31, 2009 and 2010, DCE generated approximately $1.8 million, $7.9 million and $11.3 million, respectively, in revenue from sales of biomethane, all of which is included in our consolidated statements of operations.

On April 3, 2009, DCE entered into a fifteen year gas sale agreement with Shell Energy North America (US), L.P. ("Shell") for the sale by DCE to Shell of biomethane produced by DCE's landfill gas processing facility.

DCE retains the right to reserve from the gas sale agreement up to 500 MMBtus per day of biomethane for sale as a vehicle fuel. To the extent that DCE produces volumes of biomethane in excess of the volumes sold under the agreement with Shell, DCE will either attempt to sell such volumes at then-prevailing market prices or seek to enter into another gas sale agreement in the future. There is no guarantee that DCE will produce or be able to sell up to the maximum volumes called for under the agreement, and DCE's ability to produce such volumes of biomethane is dependent on a number of factors beyond DCE's control including, but not limited to, the availability and composition of the landfill gas that is collected, the impact on DCE's operations of the operation of the landfill by the City of Dallas and the reliability of the processing plant's critical equipment. The processing equipment is currently being expanded and upgraded, which may result in significant down time to complete the work, which consequently may reduce DCE's sales of biomethane during the expansion and upgrade work. The expansion and upgrade work is anticipated to continue into the first half of 2012.

The sale price for the gas under the agreement with Shell is fixed. The sale price for the gas represents a substantial premium to the current prevailing prices for natural gas at March 8, 2011.

The gas sale agreement is terminable by either party on thirty days' written notice if the California Energy Commission makes a written determination or adopts a ruling or regulation after the date of the agreement that the biomethane sold under the agreement will, from the date of such ruling or regulation, no longer qualify as a California Renewable Portfolio Standard eligible fuel. In addition, Shell has the right to terminate the agreement upon thirty days' written notice if the volumes of biomethane produced and delivered, calculated monthly on a rolling two-year average, are less than an annual average of 630,720 MMBtu per year (or 2,083 MMBtu per day).

Vehicle Conversions

On October 1, 2009, we purchased all of the outstanding shares of BAF. Founded in 1992, BAF provides natural gas vehicle conversions, alternative fuel systems, application engineering, service and warranty support and research and development. BAF's vehicle conversions include taxis, limousines, vans, pick-up trucks and shuttle buses. BAF utilizes advanced natural gas system integration technology and has certified NGVs under both EPA and CARB standards achieving Super Ultra Low Emission Vehicle emissions. We generate revenues through the sale of natural gas vehicles that have been converted to run on natural gas by BAF. The majority of BAF's revenue during 2010 was derived from sales of converted natural gas service vans to AT&T and Verizon. During the fourth quarter of 2009 and for the year ended December 31, 2010, BAF contributed approximately $6.9 million and $42.3 million, respectively, to our revenue.

Natural Gas Fueling Compressors

On September 7, 2010, the Company, acting through certain of its subsidiaries, completed its purchase of IMW. IMW manufactures and services advanced, non-lubricated natural gas fueling compressors and related equipment for the global natural gas fueling market. IMW is headquartered near Vancouver, British Columbia, has a second manufacturing facility near Shanghai, China and has sales and service offices in Bangladesh, Columbia and the United States. Since the September 7, 2010 acquisition date, IMW contributed approximately $17.8 million to our revenue.

Volatility of Earnings and Cash Flows

Our earnings and cash flows historically have fluctuated significantly from period to period based on our futures activities, as all of our futures contracts entered into prior to June 30, 2008 have not qualified for hedge accounting under the relevant derivative accounting guidance. We have therefore recorded any changes in the fair market value of these contracts that did not qualify for hedge accounting directly in our statements of operations in the line item derivative (gains) losses along with any realized gains or losses generated during the period. For example, we experienced derivative loss of $0.3 million in the year ended December 31, 2008. Subsequent to June 30, 2008, our futures contracts did qualify for hedge accounting, so we had no derivative gains or losses in the years ended December 31, 2009 and 2010 related to our futures contracts. In accordance with our natural gas hedging policy, we plan to structure all subsequent futures contracts as cash flow hedges under the applicable derivative accounting guidance, but we cannot be certain that they will qualify. See "Risk Management Activities" below. If the futures contracts do not qualify for hedge accounting, we could incur significant increases or decreases in our earnings based on fluctuations in the market value of the contracts from period to period.

Additionally, we are required to maintain a margin account to cover losses related to our natural gas futures contracts. Futures contracts are valued daily, and if our contracts are in loss positions at the end of a trading day, our broker will transfer the amount of the losses from our margin account to a clearinghouse. If at any time the funds in our margin account drop below a specified maintenance level, our broker will issue a margin call that requires us to restore the balance. Consequently, these payments could significantly impact our cash balances. At December 31, 2010, we had $6.5 million on deposit in margin accounts, which are included in prepaid expenses and other current assets and notes receivable and other long-term assets on the balance sheet.

The decrease in the value of our futures positions and any required margin deposits on our futures contracts that are in a loss position could significantly impact our financial condition in the future.

Volatility of Earnings Related to Series I Warrants

Beginning January 1, 2009, under Financial Accounting Standards Board ("FASB") authoritative guidance, we are required to record the change in the fair market value of our Series I warrants in our consolidated financial statements. We recognized a loss (gain) of $17.4 million and ($10.3) million related to recording the fair market value changes of our Series I warrants in the years ended December 31, 2009 and December 31, 2010, respectively. See note 9 to our consolidated financial statements contained elsewhere herein. Our earnings or loss per share may be materially impacted by future gains or losses we are required to take as a result of valuing our Series I warrants. On November 10, 2010, 1,183,712 of the Series I warrants were exercised and are no longer outstanding.

Volatility of Earnings Related to Contingent Consideration

Under recent business combination accounting guidance, we are required to record the change in the value of the contingent consideration related to our acquisitions of both BAF and IMW in our financial statements through the contingency period, which expires December 31, 2011 for BAF and March 31, 2014 for IMW.

If the anticipated results of BAF or IMW increase or decrease during future periods, we may be required to recognize material losses or gains based on the valuation of the increased or decreased consideration due to the former BAF and IMW shareholders. To record the change in value of the BAF contingent consideration, we recognized losses of $0.3 million and $0.2 million during the quarters ended March 31, 2010 and June 30, 2010, respectively, and we recognized a gain of $0.5 million during the quarter ended September 30, 2010. There was no change during the quarter ended December 31, 2010. Subsequent to September 7, 2010, the closing date of the acquisition of IMW, we determined that no adjustment was required to the value of the contingent consideration owed to the former IMW shareholder during the quarter ended September 30, 2010, and we recognized a gain of $1.2 million during the quarter ended December 31, 2010 related to this obligation. Our earnings or loss per share may be materially impacted by future gains or losses we are required to take as a result of changes in the contingent consideration amount.

Debt Compliance

Our credit agreement with PCB ("Credit Agreement") requires us to comply with certain covenants. We may not incur indebtedness or liens except as permitted by the Credit Agreement, or declare or pay dividends. We must maintain, on a quarterly basis, minimum liquidity of not less than $6.0 million, accounts receivable balances, as defined, of not less than $8.0 million, consolidated net worth, as defined, of not less than $150.0 million, and a debt to equity ratio, as defined, of not more than 0.3 to 1.0. Beginning in the quarter ended June 30, 2009, we must also maintain a debt service ratio, as defined, of not less than 1.5 to 1.0 at each quarter end. In computing these amounts, we exclude the financial results and amounts of IMW. Effective in the fourth quarter of 2008, we established a lock-box arrangement with PCB subject to the Credit Agreement. Funds received from our customers are remitted to the lock-box and then deposited to a PCB bank account. The remitted funds are not used to pay-down the balance of the Credit Agreement unless there is an event of default on the Credit Agreement. One of the events of default is the occurrence of a "material adverse change," which is a subjective acceleration clause. Based on the relevant accounting guidance, we have classified our debt pursuant to the Credit Agreement as short-term or long-term, as appropriate, and we believe the likelihood of an event of default is more than remote but not more likely than not. If we default on the Credit Agreement, all of the obligations under the Credit Agreement will become immediately due and payable and all funds received in our lockbox held by PCB, plus $2.5 million we have deposited with PCB in a payment reserve account, will be applied to the balance due on the Credit Agreement. To the extent natural gas prices continue to fall, our volumes decline or our operating results do not materialize as planned, we could violate our covenants in the future. In the event we violate our covenants, we would seek a waiver from the bank. We were in compliance with all of our covenants at December 31, 2010.

Pursuant to the recent acquisition of IMW, our credit agreement with HSBC also requires that IMW complies with certain financial covenants as detailed in note 7 of our consolidated financial statements contained elsewhere herein. Among those financial covenants are that IMW shall not permit 1) its ratio of debt to tangible net worth to be greater than 3.25 to 1.0 until December 31, 2010 and greater than 3.00 to 1.0 on and after January 1, 2011, 2) its tangible net worth to at anytime be below CAD$3.0 million and 3) its ratio of current assets to current liabilities to be less than 1.15 to 1.0 until December 31, 2010 and less than 1.25 to 1.0 on and after January 1, 2011. Should IMW's operating results not materialize as planned, we could violate these covenants. If we were to violate a covenant, we would seek a waiver from the bank, which the bank is not obligated to grant. If the bank does not grant a waiver, all of the obligations under the credit agreement would be due and payable. IMW was in compliance with these covenants as of December 31, 2010.

Risk Management Activities

Historically, a significant portion of our natural gas fuel sales have been covered by contracts to sell LNG or CNG to our customers at a fixed price or a variable index based price subject to a cap. These contracts expose us to the risk that the price of natural gas may increase above the natural gas cost component included in the price at which we are committed to sell gas to our customers. We account for sales of natural gas under these contracts as described below in "Critical Accounting Policies—Fixed Price and Price Cap Sales Contracts."

In an effort to mitigate the volatility of our earnings related to our futures contracts and to reduce our risk related to fixed price sales contracts, our board of directors revisited our risk management policies and procedures and adopted a revised natural gas hedging policy in February 2007, which was amended effective May 29, 2008, and restricts our ability to purchase natural gas futures contracts and offer fixed price sales contracts to our customers. Unless otherwise agreed in advance by the board of directors and the derivative committee, we will conduct our futures activities and enter into fixed price sales contracts only in accordance with the natural gas hedging policy, a complete copy of which was filed as Exhibit 99.1 to our Form 8-K filed with the SEC on June 20, 2008. Pursuant to the policy, we only purchase futures contracts to hedge our exposure to variability in expected future cash flows related to a particular fixed price contract or bid. Subject to the conditions set forth in the policy, we purchase futures contracts in quantities reasonably expected to hedge effectively our exposure to cash flow variability related to such fixed price sales contracts entered into after the date of the policy. The summary of the policy described above does not purport to be complete and is qualified in its entirety by reference to the copy of the policy previously filed.

Due to the restrictions of our revised hedging policy, we expect to offer fewer fixed price sales contracts to our customers. If we do offer a fixed price sales contract, we anticipate including a price component that would cover our increased costs as well as a return on our estimated cash requirements over the duration of the underlying futures contracts. The amount of this price component will vary based on the anticipated volume and the natural gas price component to be covered under the fixed price sales contracts.

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles ("US GAAP"). The preparation of financial statements requires management to make estimates and judgments that affect the reported amounts of assets and liabilities, revenue and expenses, and disclosures of contingent assets and liabilities as of the date of the financial statements.

On a periodic basis, we evaluate our estimates, including those related to revenue recognition, asset realization, accounts receivable reserves, notes receivable reserves, warranty reserves, derivative values, income taxes, and the fair value of equity instruments granted as stock-based compensation. We use historical experience, market quotes, and other assumptions as the basis for making estimates. Actual results could differ from those estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

Impairment of Goodwill and Long-lived Assets

We evaluate the carrying value of goodwill during the fourth quarter of each fiscal year and between annual evaluations if events occur or circumstances change that would more likely than not reduce the fair value of the goodwill below its carrying amount. Such circumstances could include, but are not limited to: (i) a significant adverse change in legal factors or in business climate, (ii) unanticipated competition, or (iii) an adverse action or assessment by a regulator. In performing the impairment review, we determine the carrying amount of each reporting unit by assigning assets and liabilities, including the existing goodwill, to those reporting units. A reporting unit is defined as an operating segment or one level below an operating segment. A component of an operating segment is deemed a reporting unit if the component constitutes a business for which discrete financial information is available and management regularly reviews the operating results of that component. More than one component can be combined in to one reporting unit assuming certain aggregation criteria are met.

To evaluate whether goodwill is impaired, we compare the fair value of the reporting unit to which the goodwill is assigned to the reporting unit's carrying amount, including goodwill. We determine the fair value of each reporting unit using the present value of expected future cash flows for that reporting unit. If the carrying amount of a reporting unit exceeds its fair value, then the amount of the impairment loss must be measured. The impairment loss would be calculated by comparing the implied fair value of reporting unit goodwill to its carrying amount. In calculating the implied fair value of reporting unit goodwill, the fair value of the reporting unit is allocated to all of the other assets and liabilities of that unit based on their fair values. The excess of the fair value of a reporting unit over the amount assigned to its other assets and liabilities is the implied fair value of goodwill. An impairment loss would be recognized when the carrying amount of goodwill exceeds its implied fair value. To date, we have had no impairments of goodwill.

We test tangible and intangible long-lived assets with definite useful lives for impairment whenever circumstances or events may affect the recoverability of the long-lived assets. The evaluation is primarily dependent on the estimated future cash flows of the assets and the fair value of these items, as determined by management based on a number of estimates, including future cash flow projections, discount rates and terminal values. In determining these estimates, management considered internally generated information and information obtained from discussions with market participants. The determination of fair value requires significant judgment both by management and outside experts engaged to assist in this process.

The impairment test for long-lived assets is a two step process. The first step is to assess if events or changes in circumstances have affected the recoverability of long-lived assets. If management believes that recoverability has been affected, then step two requires management to calculate the undiscounted future cash flow related to the asset or asset group and to compare the cash flow to the carrying value of the asset or asset group. If the undiscounted future cash flows exceed the carrying value, then there is no impairment.

During the fourth quarter of 2010, we recorded an impairment charge of $1.5 million related to an operating and maintenance contract we lost in a competitive bid to a competitor. In addition, during the fourth quarter of 2010, our subsidiary, DCE, expensed approximately $0.7 million of costs related to equipment that was replaced as part of its expansion of the McCommas Bluff landfill in Dallas, Texas.

Warranty Reserves

Our warranty periods range up to thirty-six months, depending on the product or service. We provide a warranty reserve for estimated product warranty costs at the time the net sales are recognized. Although we engage in quality programs and processes, our warranty obligation is affected by product failure rates and the cost of the failed product. We continuously monitor and analyze warranty claims and maintain a reserve for the related warranty costs based on historical experience and assumptions. If actual failure rates and the resulting cost of repair vary from our historically based estimates, revisions to the estimated warranty reserve would be required.

Natural Gas Derivative Activities

FASB authoritative guidance for our derivative instruments, specifically our natural gas futures contracts, requires the recognition of all derivatives as either assets or liabilities in the consolidated balance sheet and the measurement of those instruments at fair value to the extent they qualify for hedge accounting. For those contracts that do not qualify for hedge accounting, we record the changes in the fair value of the derivatives directly to our consolidated statements of operations. For those contracts that do qualify for hedge accounting, we record the changes in the fair value in our consolidated balance sheet as a component of stockholders' equity. We determine the fair value of our derivatives at the end of each reporting period based on quoted market prices from the NYMEX discounted to reflect the time value of money for contracts related to future periods.

The counter-party to our derivative transactions is a high credit quality counterparty, however, we are subject to counterparty credit risk to the extent the counterparty to the derivatives is unable to meet its settlement commitments. We manage this credit risk by minimizing the number and size of its derivative contracts and by actively monitoring the creditworthiness of our counterparties. We record valuation adjustments against the derivative assets to reflect counterparty risk, if necessary. The counterparty is also exposed to credit risk by us, which requires us to provide cash deposits as collateral when our contracts are in a liability position in the aggregate.

Revenue Recognition

We recognize revenue on our gas sales and for our O&M services in accordance with US GAAP, which requires that four basic criteria must be met before revenue can be recognized: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred and title and the risks and rewards of ownership have been transferred to the customer or services have been rendered; (3) the price is fixed or determinable; and (4) collectability is reasonably assured. Applying these factors, we typically recognize revenue from the sale of natural gas at the time fuel is dispensed or, in the case of LNG sales agreements, delivered to our customers' storage facilities. We recognize revenue from O&M agreements as we provide the related services.

In certain transactions with our customers, we agree to provide multiple products or services, including construction of and either leasing or sale of a station, providing O&M to the station, and sale of fuel to the customer. We evaluate the separability of revenues based on current FASB authoritative guidance, which provides a framework for establishing whether or not a particular arrangement with a customer has one or more revenue elements. Prior to 2010, to the extent we had adequate objective evidence of the values of the separate elements indentified as part of a contract, we allocated the revenue from the contract on a relative fair value basis at the inception of the arrangement. During 2008 and 2009, we did not have objective evidence for our multi-element arrangements, which generally resulted in the deferral of revenue until the future services are performed. However, in 2010, we elected to apply newly issued FASB authoritative guidance that allows us to use a combination of objective and reliable evidence to develop management's best estimate of the fair value of the undelivered element. If the arrangement contains a lease, we use the existing evidence of fair value to separate the lease from the other elements in the arrangement.

We recognize revenue related to our leasing activities in accordance with current FASB authoritative guidance. Our existing station leases are sales-type leases, giving rise to profit at the delivery of the leased station. Unearned revenue is amortized into income over the life of the lease using the effective-interest method. For those arrangements, we recognize gas sales and O&M service revenues as earned from the customer on a volume-delivered basis.

We typically recognize revenue on long-term fueling station construction projects where we sell the station to the customer using the completed-contract method. However, for IMW and Northstar, we use the percentage-of-completion method of accounting. In those circumstances, revenue is recognized as work on a contract progresses, based on cost incurred in relation to total estimated costs to be incurred for that project.

We recognize revenue on biomethane sales and vehicle sales when we transfer title of the gas or vehicle to our customer.

Stock-Based Compensation

We recognize compensation expense related to stock options granted to employees based on the grant date fair value. Our assessment of the estimated fair value of the stock options granted is affected by our stock price as well as assumptions regarding a number of complex and subjective variables and the related tax impact. We utilize the Black-Scholes model to estimate the fair value of stock options granted.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. This model also requires the input of highly subjective assumptions, including: the expected volatility of our common stock price, expected dividends, if any, expected life of the stock option, and the risk free interest rate appropriate for the expected holding period.

Income Taxes

We compute income taxes under the asset and liability method. This method requires the recognition of deferred tax assets and liabilities for temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. The impact on deferred taxes of changes in tax rates and laws, if any, are applied to the years during which temporary differences are expected to be settled and are reflected in the consolidated financial statements in the period of enactment. We record a valuation allowance against any deferred tax assets when management determines it is more likely than not that the assets will not be realized. When evaluating the need for a valuation analysis, we use estimates involving a high degree of judgment including projected future income and the amounts and estimated timing of the reversal of any deferred tax liabilities.

We operate within multiple domestic and foreign taxing jurisdictions and are subject to audit in these jurisdictions. These audits can involve complex issues, which may require an extended period of time for resolution. Although we believe that adequate consideration has been given to such issues, it is possible that the ultimate resolution of such issues could be significantly different than originally estimated.

Recently Issued Accounting Pronouncements

See Note 1 to our consolidated financial statements contained elsewhere herein.

Results of Operations

Fiscal Year Ended December 31, 2010 Compared to Fiscal Year Ended December 31, 2009

Revenue. Revenue increased by $80.3 million to $211.8 million in the year ended December 31, 2010, from $131.5 million in the year ended December 31, 2009. A portion of this increase was the result of an increase in the number of gallons delivered between periods from 101.0 million gasoline gallon equivalents to 122.7 million gasoline gallon equivalents. The increase in volume was primarily from an increase in CNG sales of 13.5 million gallons. The acquisition of four compressed natural gas operations and maintenance services contracts in May and June of 2009, four new refuse customers, two new transit customers, and one regional trucking customer together accounted for 11.3 million gallons of the CNG volume increase. The volume growth from our existing public, refuse and transit customers, combined with the volume growth from our share of our joint venture in Peru, contributed to the remaining CNG volume increase. We also experienced an increase of 7.2 million gallons in LNG volume between periods, which was primarily due to the volume growth of 2.3 million gallons from our existing transit and refuse customers, combined with a 3.8 million gallon increase from our port trucking customers. We also had a LNG volume increase of 1.0 million gallons from two new refuse customers. We had an increase in biomethane sales (our 70% share of the biomethane sales at DCE) of 1.0 million gallons. Revenue also increased between periods by $35.4 million from sales of natural gas conversion equipment and vehicles by BAF, which we acquired on October 1, 2009. Our acquisitions of IMW on September 7, 2010 and Northstar on December 15, 2010 contributed $17.8 million and $0.7 million, respectively, to our increased revenue between periods. We also experienced a $5.6 million increase, excluding Northstar, in station construction revenues between periods. Revenue attributable to VETC also increased between periods as we recorded $16.0 million of revenue related to fuel tax credits in 2010, compared to $15.5 million in 2009. These increases were offset by the decrease in our effective price per gallon charged between periods. Our effective price per gallon was $0.99 for the year ended December 31, 2010, which represents a $0.01 per gallon decrease from $1.00 in the year ended December 31, 2009. This decrease is primarily due to the acquisition of certain O&M agreements in 2009 and 2010 that generate less revenue per gallon than contracts where we supply the natural gas commodity.

Cost of sales. Cost of sales increased by $59.0 million to $141.9 million in the year ended December 31, 2010, from $82.9 million in the year ended December 31, 2009. Our cost of sales primarily increased between periods as a result of delivering more volume to our customers together with $25.4 million of increased costs related to BAF's vehicle equipment sales, which we began to recognize on October 1, 2009 when we acquired the company. Our acquisition of IMW on September 7, 2010 and Northstar on December 15, 2010 contributed $14.0 million and $0.5 million, respectively, to our increased cost of sales between periods. We also experienced a $4.4 million increase in station construction costs between periods. These increases were offset by the decrease in our effective cost per gallon of $0.01 per gallon, to $0.70 per gallon during 2010. This decrease was primarily the result of certain O&M contracts that we acquired in 2009 and 2010 that are included in our volume totals but do not increase our cost of sales amount significantly as we do not pay for the natural gas consumed at the properties.

Selling, general and administrative. Selling, general and administrative expenses increased by $15.8 million to $63.3 million in the year ended December 31, 2010, from $47.5 million in the year ended December 31, 2009. A significant portion of this increase was the result of our salaries and benefits amount increasing by $7.2 million between periods as we increased our employee headcount from 229 at December 31, 2009 to 710 (including the addition of 420, 70 and 23 IMW, BAF and

Northstar employees, respectively) at December 31, 2010. We also experienced a $3.8 million increase in business insurance, contract labor, software/hardware maintenance, training/seminars and office supplies related to our continued business growth and our acquisitions of IMW and Northstar in 2010. Our travel and entertainment expenses increased $1.9 million between periods, primarily due to the increased travel of our sales team. In addition, our professional fees increased $1.8 million between periods, primarily for legal, audit and consulting services related to the acquisitions of IMW and Northstar. 2009 includes a reversal of a bad debt for $1.3 million that did not recur in 2010. Our marketing expenses increased $1.1 million between periods primarily due to certain advertising we conducted related to the Ports of Los Angeles and Long Beach and the refuse sector. During the fourth quarter of 2010, we recorded an impairment charge of $1.5 million related to an intangible asset as one of the contracts we acquired in 2009 was lost through a competitive bidding process, and $0.7 million at our DCE subsidiary related to equipment that was replaced as part of their expansion of the McCommas Bluff landfill in Dallas, Texas. Offsetting these increases was a decrease of $2.2 million between periods related to our stock-based compensation expense and a decrease of $1.2 million during the fourth quarter of 2010 related to a decrease in the IMW contingent consideration liability.

Depreciation and amortization. Depreciation and amortization increased by $5.5 million to $22.5 million in the year ended December 31, 2010, from $17.0 million in the year ended December 31, 2009. This increase was primarily due to additional depreciation expense in the year ended December 31, 2010 related to increased property and equipment balances between periods, primarily related to our expanded station network. Our 2010 amortization expense includes increased amortization of the intangible assets we obtained in connection with our acquisition of the operation and maintenance contracts we acquired during the second quarter of 2009, BAF in the fourth quarter of 2009, IMW in the third quarter of 2010, and Northstar in the fourth quarter of 2010.

Derivative (gain) loss on Series I warrant valuation. Derivative (gain) loss decreased by $27.7 million to a gain of $10.3 million in the year ended December 31, 2010, from a loss of $17.4 million in the year ended December 31, 2009. The amounts represent the non-cash impact with respect to valuing our outstanding Series I warrants based on our mark-to-market accounting for the warrants (see note 9 to our consolidated financial statements contained elsewhere herein) during the periods.

Interest income (expense), net. Interest income (expense), net, increased by $1.2 million from $0 to $1.2 million of expense for the year ended December 31, 2010. This increase was primarily the result of an increase in interest expense in the year ended December 31, 2010 related to debt we incurred related to the acquisition of IMW.

Other income (expense), net. Other income (expense), net, increased by $2.4 million to $2.1 million of income for the year ended December 31, 2010, from a loss of $0.3 million for the year ended December 31, 2009. This increase was primarily due to the impact of foreign currency exchange gains at IMW.

Income (loss) from equity method investment. During 2010, we recorded equity income of $0.4 million related to our 49% interest in our Peruvian joint venture, and in 2009, we recorded a gain of $0.2 million related to our interest.

Loss (income) of noncontrolling interest. During the year ended December 31, 2010, we recorded $0.3 million for the noncontrolling interest in the net loss of DCE, compared to $0.4 million for the noncontrolling interest in the net loss of DCE in the year ended December 31, 2009. The noncontrolling interest represents the 30% interest of our joint venture partner.

Fiscal Year Ended December 31, 2009 Compared to Fiscal Year Ended December 31, 2008

Revenue. Revenue increased by $5.6 million to $131.5 million in the year ended December 31, 2009, from $125.9 million in the year ended December 31, 2008. A portion of this increase was the result of an increase in the number of gallons delivered from 73.5 million gasoline gallon equivalents to 101.0 million gasoline gallon equivalents. Revenue also increased by $6.9 million from sales of natural gas conversion equipment and vehicles by BAF, which we acquired on October 1, 2009, and $5.6 million in increased station construction revenue between periods. The increase in volume was primarily from an increase in CNG sales of 20.3 million gallons and an increase in biomethane sales (our 70% share of the biomethane sales of DCE) of 4.4 million gallons. The acquisition of four compressed natural gas operations and maintenance services contracts in May and June, eight new refuse customers, and one new transit customer together accounted for 17.5 million gallons of the CNG volume increase. The volume growth from our joint venture in Peru and from existing refuse and transit customers contributed to the remaining CNG volume increase. We believe that the biomethane sales increase was primarily attributable to our investment in new wells and the capital upgrades to the processing plant that we completed in the first quarter of 2009. We also experienced an increase of 2.8 million gallons in LNG volume between periods, which was primarily due to the volume growth from our port trucking customers. These increases were offset by the decrease in our effective price per gallon charged between periods. Our effective price per gallon was $1.00 in the year ended December 31, 2009, which represents a $0.45 per gallon decrease from $1.45 in the year ended December 31, 2008. This decrease is primarily due to the decreased price of natural gas in 2009, upon which a significant portion of our revenues are based. In the majority of our contracts, natural gas commodity prices are a direct pass-through to our customer or the customer pays for the natural gas commodity themselves. Revenue attributable to VETC also decreased between periods as we recorded $15.5 million of revenue related to fuel tax credits in 2009, compared to $17.2 million in 2008 due to the fact that a few of our customers began collecting the credit that we had previously collected.

Cost of sales. Cost of sales decreased by $15.9 million to $82.9 million in the year ended December 31, 2009, from $98.8 million in the year ended December 31, 2008. Our cost of sales primarily decreased between periods as a result of our effective cost per gallon declining by $0.62 per gallon to $0.71 in 2009, primarily due to the decreased price of natural gas in 2009. Offsetting this decrease was a $19.5 million increase in costs related to delivering more volume between periods together with $4.7 million of costs related to BAF's vehicle sales, which we began to recognize on October 1, 2009 when we acquired the company. We also experienced a $5.2 million increase in station construction costs between periods.

Selling, general and administrative. Selling, general and administrative expenses decreased by $14.9 million to $47.5 million in the year ended December 31, 2009, from $62.4 million in the year ended December 31, 2008. Our marketing expenses decreased $20.5 million between periods primarily because we did not incur certain advertising costs related to the Ports of Los Angeles and Long Beach and to support the Clean Alternative Fuels Act in California in 2009 as we did in 2008. Our bad debt expense decreased $1.4 million between periods due to a reversal of our BAF loan loss provision in the third quarter of 2009. Our professional service fees decreased $1.0 million between periods primarily due to reduced legal, audit and consulting services. These decreases were offset by $3.3 million increase in stock option expense between periods, primarily due to the expensing of options granted to our employees in December 2008 and January 2009, and an increase of $2.4 million in bonus expense between periods due to higher anticipated payouts in 2009. There was also an increase of $2.2 million in salaries and benefits between periods primarily related to the hiring of additional employees. Our employee headcount increased from 140 at December 31, 2008 to 229 at December 31, 2009.

Depreciation and amortization. Depreciation and amortization increased by $7.4 million to $17.0 million in the year ended December 31, 2009, from $9.6 million in the year ended December 31,

2008. This increase was primarily due to additional depreciation expense in the year ended December 31, 2009 related to increased property and equipment balances between periods, including our expanded station network and our California LNG plant. Our December 31, 2009 amortization amount also includes amortization of the City of Dallas landfill gas lease that we acquired in connection with our acquisition of DCE on August 15, 2008 and amortization of the intangible assets we obtained in connection with our acquisition of the operation and maintenance contracts we acquired during the second quarter of 2009 and BAF in the fourth quarter of 2009.

Derivative losses. Derivative losses increased by $16.8 million to $17.4 million in the year ended December 31, 2009, from $0.6 million in the year ended December 31, 2008. The 2009 amount represents the impact of our mark-to-market accounting for our Series I warrants (see note 20 to our consolidated financial statements contained elsewhere herein). The 2008 amount represents a loss we recognized in the year ended December 31, 2008 with respect to the sale of certain futures contracts we purchased in conjunction with the portion of a fixed priced bid on an LNG supply contract.

Interest income (expense), net. Interest income (expense), net, decreased by $1.7 million to $32,000 of expense for the year ended December 31, 2009. This decrease was primarily the result of an increase in interest expense in the year ended December 31, 2009 related to debt we incurred with PCB to acquire our 70% interest in DCE on August 15, 2008.

Other income (expense), net. Other income (expense), net, increased by $141,000 to $311,000 of expense for the year ended December 31, 2009. This increase was primarily related to the write-off of certain non-recoverable station costs in the year ended December 31, 2009 that did not occur in the year ended December 31, 2008.

Income (loss) from equity method investment. During 2009, we recorded equity income of $244,000 related to our 49% interest in our Peruvian joint venture, and in 2008, we recorded a loss of $188,000 related to our interest.

Loss (income) of noncontrolling interest. During the year ended December 31, 2009, we recorded $439,000 for the noncontrolling interest in the net loss of DCE. The noncontrolling interest represents the 30% interest of our joint venture partner. In 2008, we recorded $105,000 for the non-controlling interest in the net loss of DCE.

Seasonality and Inflation

To some extent, we experience seasonality in our results of operations. Natural gas vehicle fuel amounts consumed by some of our customers tends to be higher in summer months when buses and other fleet vehicles use more fuel to power their air conditioning systems. Natural gas commodity prices tend to be higher in the fall and winter months due to increased overall demand for natural gas for heating during these periods.

Since our inception, inflation has not significantly affected our operating results. However, costs for construction, repairs, maintenance, electricity and insurance are all subject to inflationary pressures and could affect our ability to maintain our stations adequately, build new stations, build new LNG plants and expand our existing facilities or materially increase our operating costs.

Liquidity and Capital Resources

Historically, our principal sources of liquidity have consisted of cash provided by operations and financing activities. In May 2007, we completed our initial public offering of 10,000,000 shares of common stock at a public offering price of $12.00 per share. Net cash proceeds from the initial public offering were approximately $108.5 million, after deducting underwriting discounts, commissions and offering expenses. On August 15, 2008, in connection with our acquisition of 70% of the membership interests of DCE, we entered into a credit agreement with PCB pursuant to which we borrowed $18.0 million under a term loan and an additional $12.0 million under a line of credit (see note 7 to the accompanying consolidated financial statements). On September 24, 2008, we sold 319,488 shares of our common stock at a price of $15.65 per share to Boone Pickens Interests, Ltd. for proceeds of approximately $5.0 million. On November 3, 2008, we sold 4,419,192 units of common stock and warrants for $7.92 per unit and we raised net proceeds of approximately $32.5 million after deducting offering costs. On July 1, 2009, we sold 9,430,000 shares of our common stock to third party investors and received net proceeds of $73.2 million. On November 11, 2010, we sold 3,450,000 shares of our common stock, primarily to third party investors, and received net proceeds of $42.6 million. Additionally, on November 10, 2010, we entered into an amendment with one of the holders of the Series I warrants pursuant to which the expiration date of such warrant for the purchase of 1,183,712 shares of common stock was changed to November 10, 2010 and the warrants were exercised on this date. Proceeds, net of offering costs from the exercise of the Series I warrants, totaled $11.8 million. On October 7, 2009, we repaid the $18.0 million term loan with PCB and simultaneously amended the Credit Agreement to obtain a $20 million line of credit ("LOC") from PCB. The $20 million LOC expires August 14, 2011, but we have a one year renewal option we can exercise as long as we are not in default on the PCB debt facilities. As of December 31, 2010, we have not drawn any loan amounts under the LOC and we had an outstanding balance of $9.9 million on our Facility B Loan. As of December 31, 2010, IMW had an outstanding balance of $4.6 million under the IMW Lines of Credit and a balance of $44.6 million under the IMW Notes.

In addition to funding operations, our principal uses of cash have been, and are expected to be, the construction of new fueling stations, construction of LNG production facilities, the purchase of new LNG tanker trailers, investment in biomethane production, mergers and acquisitions, the financing of natural gas vehicles for our customers and general corporate purposes, including making deposits to support our derivative activities, geographic expansion (domestically and internationally), expanding our sales and marketing activities, support of legislative initiatives and for working capital for our expansion. We have also acquired and may continue to seek to acquire and invest in companies or assets in the natural gas and biomethane fueling infrastructure, services and production industries. On December 15, 2010, the Company acquired 100% of the equity interests of Northstar. The purchase price primarily consisted of a closing cash payment in the amount of $7.4 million. The remaining consideration consisted of annual future payments in the amount of $0.7 million, commencing on the first anniversary of the closing date and ending on the fifth anniversary of the closing date. The Company has also committed to pay up to $4.0 million in retention bonuses to certain key employees commencing on the first anniversary of the closing and ending on the fourth anniversary of the closing date. We financed our operations in 2010 primarily through cash on hand and cash provided by financing activities.

At December 31, 2010, we had total cash and cash equivalents of $55.2 million, compared to $67.1 million at December 31, 2009.

Cash used in operating activities was $4.0 million for 2010, compared to $13.3 million of cash provided by operating activities in 2009. Our operating cash flow, before working capital changes, increased between periods, mostly due to the improved operating results at BAF in 2010. Offsetting this increase was a decrease in our working capital amounts between periods, primarily caused by an increase in receivable balances between periods. The biggest increase between periods related to our fuel tax credit receivable, which increased $15.0 million from 2009 to 2010. We anticipate receiving approximately $16.0 million of our tax credit receivables in the second quarter of 2011.

Cash used in investing activities was $68.7 million for 2010, compared to $43.4 million for 2009. Our purchases of property and equipment were $50.5 million during 2010, compared to $30.5 million in 2009. In 2009, we acquired four compressed natural gas operations and maintenance service contracts and BAF for $10.4 million. In 2010, we paid $20.5 million related to our acquisitions of IMW and

Northstar. We made an additional investment in the Vehicle Production Group, LLC ("VPG"), a company developing a CNG taxi and a paratransit vehicle, during 2009 of $5.6 million, compared to $0.4 million for the same period in 2010.

Cash provided by financing activities for 2010 was $62.6 million, compared to $60.9 million for 2009. In 2009, we received net proceeds of $73.8 million from the issuance of common stock and the exercise of stock options. In 2010, we received net proceeds of $53.6 million from the issuance of common stock and the exercise of stock options. Also in 2010, we received net proceeds of $11.5 million related to the exercise of 1,183,712 Series I warrants. In 2009, we drew $7.2 million from PCB to fund capital expenditures related to DCE's landfill plant upgrade and paid back $20.0 million of capital lease obligations and debt instruments during the year. In 2010, we drew $12.7 million and paid $14.3 million under IMW's revolving line of credit. We also made payments of $1.1 million on our capital lease obligations and debt instruments during the year.

Our financial position and liquidity are, and will be, influenced by a variety of factors, including our ability to generate cash flows from operations, deposits and margin calls on our futures positions, the level of any outstanding indebtedness and the interest we are obligated to pay on this indebtedness, our capital expenditure requirements (which consist primarily of station construction, LNG plant construction costs, DCE plant construction costs and the purchase of LNG tanker trailers and equipment) and any merger or acquisition activity.

Capital Expenditures

Our business plan calls for approximately $80.7 million in capital expenditures in 2011, primarily related to construction of new fueling stations. We may also elect to invest additional amounts in expansion of our California LNG plant, expansion of our DCE landfill gas processing plant, construction of a Michigan landfill gas processing plant, or for other acquisitions or investments in companies or assets in the natural gas fueling infrastructure, services and production industries, including biomethane production. We will need to raise additional capital as necessary to fund any expansion of our California LNG plant or DCE landfill gas plant, acquisitions or other capital expenditures or investments that we cannot fund through available cash, our line of credit from PCB, the potential exercise of a warrant for 15,000,000 shares of our common stock at an exercise price of $10 per share held by Boone Pickens that expires in December 2011, or cash generated by operations. The timing and necessity of any future capital raise will depend on our rate of new station construction, which may be affected by any federal legislation that provides incentives for natural gas vehicle purchases and fuel use, any decision to expand our California LNG plant or DCE gas processing plant and potential merger or acquisition activity. For more information, see "Liquidity and Capital Resources" below. We may not be able to raise capital on terms that are favorable to existing stockholders or at all. Any inability to raise capital may impair our ability to invest in new stations, expand our California LNG plant or DCE gas processing plant, develop natural gas fueling infrastructure and invest in strategic transactions or acquisitions and reduce the ability of our business to grow and generate increased revenues.

Our credit agreement with PCB requires that we comply with certain covenants, as detailed in footnote 7 of our consolidated financial statements contained elsewhere herein. One of the covenants requires that we maintain accounts receivable balances from certain subsidiaries above $8.0 million at each quarter-end during the term. To the extent natural gas prices fall, which would result in decreased revenues, or our volumes sold decline, we could violate this covenant. Also, beginning with the quarter ending June 30, 2009, we are required to maintain a debt service ratio, as defined, of 1.5 to 1. Should our operating results not materialize as planned, we could violate this covenant. If we were to violate a covenant, we would seek a waiver from the bank, which the bank is not obligated to grant. If the bank does not grant a waiver, all of the obligations under the credit agreement will become immediately due and payable and $2.5 million of our funds held by PCB would be applied to the balance due on the PCB loans. We also would be unable to use the $20 million PCB line of credit if this were to occur. We were in compliance with all of the covenants as of December 31, 2010.

Contractual Obligations

The following represents the scheduled maturities of our contractual obligations as of December 31, 2010:

Contractual Obligations:	Payments Due by Period Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt and capital lease obligations(a)	$ 68,365,430	$23,240,427	$34,202,616	$10,922,387	$ —
Operating lease commitments(b)	22,808,211	3,165,571	6,111,567	6,014,285	7,516,788
"Take or pay" LNG purchase contracts(c)	21,896,738	4,055,925	6,116,850	6,116,850	5,607,113
Construction contracts(d)	17,901,945	17,901,945	—	—	—
Total	$130,972,324	$48,363,868	$46,431,033	$23,053,522	$13,123,901

(a) Consists of long-term debt and capital lease obligations to finance acquisitions and equipment purchases, including interest.

(b) Consists of various space and ground leases for our California LNG plant, offices and fueling stations as well as leases for equipment.

(c) The amounts in the table represent our estimates for our fixed LNG purchase commitments under two "take-or-pay" contracts.

(d) Consists of our obligations to fund various fueling station construction projects, net of amounts funded through December 31, 2010, and excluding contractual commitments related to station sales contracts.

Off-Balance Sheet Arrangements

At December 31, 2010, we had the following off-balance sheet arrangements that had, or are reasonably likely to have, a material effect on our financial condition.

- outstanding surety bonds for construction contracts and general corporate purposes totaling $34.6 million,
- two take-or-pay contracts for the purchase of LNG,
- operating leases where we are the lessee,
- operating leases where we are the lessor and owner of the equipment, and
- firm commitments to sell CNG and LNG at fixed prices.

We provide surety bonds primarily for construction contracts in the ordinary course of business, as a form of guarantee. No liability has been recorded in connection with our surety bonds as we do not believe, based on historical experience and information currently available, that it is probable that any amounts will be required to be paid under these arrangements for which we will not be reimbursed.

We have entered into two contracts that require us to purchase minimum volumes of LNG. One contract expires in June 2011 and the other contract expires in October 2017.

We have entered into operating lease arrangements for certain equipment and for our office and field operating locations in the ordinary course of business. The terms of our leases expire at various dates through 2016. Additionally, in November 2006, we entered into a ground lease for 36 acres in

California on which we built our California LNG liquefaction plant. The lease is for an initial term of thirty years and requires payments of $230,000 per year, plus up to $130,000 per year for each 30 million gallons of production capacity utilized, subject to future adjustment based on consumer price index changes. We must also pay a royalty to the landlord for each gallon of LNG produced at the facility, as well as a fee for certain other services that the landlord will provide. Commercial operations began December 1, 2008, and the fixed payments for this lease are included in "Operating lease commitments" in the "Contractual Obligations" table set forth above.

We are also the lessor in various leases with our customers, whereby our customers lease certain stations and equipment that we own.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

In the ordinary course of business, we are exposed to various market risk factors, including changes in general economic conditions, domestic and foreign competition, commodity price risk and foreign currency exchange rates.

Commodity Risk. We are subject to market risk with respect to our sales of natural gas, which has historically been subject to volatile market conditions. Our exposure to market risk is heightened when we have a fixed price or price cap sales contract with a customer that is not covered by a futures contract, or when we are otherwise unable to pass through natural gas price increases to customers. Natural gas prices and availability are affected by many factors, including weather conditions, overall economic conditions and foreign and domestic governmental regulation and relations.

Natural gas costs represented 42% (or 44% excluding BAF) of our cost of sales for 2009 and 30% (or 33% excluding BAF, IMW and Northstar) of our cost of sales for 2010. Prices for natural gas over the eleven-year period from December 31, 1999 through December 31, 2010, based on the NYMEX daily futures data, have ranged from a low of $1.65 per Mcf to a high of $19.38 per Mcf. At December 31, 2010, the NYMEX index price of natural gas was $4.27 per Mcf.

To reduce price risk caused by market fluctuations in natural gas, we may enter into exchange traded natural gas futures contracts. These arrangements also expose us to the risk of financial loss in situations where the other party to the contract defaults on its contract or there is a change in the expected differential between the underlying price in the contract and the actual price of natural gas we pay at the delivery point.

We account for these futures contracts in accordance with FASB authoritative guidance on derivatives. The accounting under this guidance for changes in the fair value of a derivative depends upon whether it has been specified in a hedging relationship and, further, on the type of hedging relationship. To qualify for designation in a hedging relationship, specific criteria must be met and appropriate documentation maintained.

The fair value of the futures contracts we use is based on quoted prices in active exchange traded or over the counter markets which are then discounted to reflect the time value of money for contracts applicable to future periods. The fair value of these futures contracts is continually subject to change due to market conditions. In an effort to mitigate the volatility in our earnings related to futures activities our board of directors adopted a revised natural gas hedging policy which restricts our ability to purchase natural gas futures contracts and offer fixed price sales contracts to our customers. We plan to structure prospective futures contracts so that they will be accounted for as cash flow hedges under this guidance, but we cannot be certain they will qualify. For more information, please read "—Risk Management Activities" above.

We have prepared a sensitivity analysis to estimate our exposure to market risk with respect to the futures contracts we hold as of December 31, 2010 to hedge the fixed price component of certain supply contracts. If the price of natural gas were to fluctuate (increase or decrease) by 10% from the price quoted on NYMEX on December 31, 2010 ($4.27 per Mcf), we could expect a corresponding fluctuation in the value of the contracts of approximately $0.9 million.

Foreign exchange rate risk. Because we have foreign operations, we are exposed to foreign currency exchange gains and losses. Since the functional currency of our foreign operations is in their local currency, the currency effects of translating the financial statements of those foreign subsidiaries, which operate in local currency environments, are included in the accumulated other comprehensive income (loss) component of consolidated equity and do not impact earnings. However, foreign currency transaction gains and losses not in our subsidiaries' functional currency do impact earnings and resulted in approximately $1.9 million of gains in 2010. During 2010 our primary exposure to foreign currency rates related to our Canadian operations that had certain outstanding notes payable denominated in the U.S. dollar that were not hedged.

We have prepared a sensitivity analysis to estimate our exposure to market risk with respect to our monetary transactions denominated in a foreign currency. If the exchange rate on these assets and liabilities were to fluctuate by 10% from the rate as of December 31, 2010, we would expect a corresponding fluctuation in the value of the assets and liabilities of approximately $4.9 million.

Quarterly Results of Operations

The following table sets forth the Company's quarterly consolidated statements of operations data for the eight quarters ended December 31, 2010. The information for each quarter is unaudited and the Company has prepared them on the same basis as the audited consolidated financial statements appearing elsewhere in this Form 10-K. This information includes all adjustments that management considers necessary for the fair presentation of such data. The quarterly data should be read together with the Company's consolidated financial statements and related notes appearing elsewhere in this Form 10-K. The results of operations for any one quarter are not necessarily indicative of results for any future period.

Quarterly Financial Data (Unaudited)
(In thousands, except share data)

	For the Quarter Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
Revenue:				
Product revenues	$28,382	$24,828	$ 26,291	$37,134
Service revenues	1,866	3,042	4,891	5,069
Total revenues	30,248	27,870	31,182	42,203
Operating expenses:				
Cost of sales:				
Product cost of sales	21,252	15,165	16,369	23,980
Service cost of sales	392	1,040	2,389	2,334
Derivative (gains) losses:				
Series I warrant valuation	177	2,210	15,422	(442)
Selling, general and administrative	11,566	11,591	10,492	13,860
Depreciation and amortization	3,617	4,123	4,517	4,735
Total operating expenses	37,004	34,129	49,189	44,467
Operating loss	(6,756)	(6,259)	(18,007)	(2,264)
Interest income (expense), net	(33)	(60)	(276)	337
Other income (expense), net	(40)	(146)	(108)	(16)
Income (loss) from equity method investments	17	36	78	113
Loss before income taxes	(6,812)	(6,429)	(18,313)	(1,830)
Income tax expense	(68)	(73)	(68)	(95)
Net loss	(6,880)	(6,502)	(18,381)	(1,925)
Loss (income) of noncontrolling interest	386	125	(80)	8
Net loss attributable to Clean Energy Fuels Corp.	$(6,494)	$(6,377)	$(18,461)	$(1,917)
Basic earnings (loss) per share	$ (0.13)	$ (0.13)	$ (0.31)	$ (0.03)
Fully diluted earnings (loss) per share	$ (0.13)	$ (0.13)	$ (0.31)	$ (0.03)

	For the Quarter Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Revenue:				
Product revenues	$ 34,273	$ 39,434	$40,975	$75,154
Service revenues	4,716	4,601	4,679	8,002
Total revenues	38,989	44,035	45,654	83,156
Operating expenses:				
Cost of sales:				
Product cost of sales	25,496	28,692	31,190	47,533
Service cost of sales	2,063	1,923	2,319	2,673
Derivative (gains) losses:				
Series I warrant valuation	18,605	(16,615)	(7,866)	(4,402)
Selling, general and administrative	13,649	14,878	15,855	18,876
Depreciation and amortization	4,991	5,070	5,507	6,919
Total operating expenses	64,804	33,948	47,005	71,599
Operating income (loss)	(25,815)	10,087	(1,351)	11,557
Interest income (expense), net	109	(22)	(70)	(1,211)
Other income (expense), net	43	(39)	(309)	2,385
Income from equity method investments	77	29	96	225
Income (loss) before income taxes	(25,586)	10,055	(1,634)	12,956
Income tax (expense) benefit	1,203	(77)	(290)	600
Net income (loss)	(24,383)	9,978	(1,924)	13,556
Loss (income) of noncontrolling interest	16	(83)	94	230
Net income (loss) attributable to Clean Energy Fuels Corp.	$(24,367)	$ 9,895	$ (1,830)	$13,786
Basic earnings (loss) per share	$ (0.41)	$ 0.16	$ (0.03)	$ 0.21
Fully diluted earnings (loss) per share	$ (0.41)	$ 0.14	$ (0.03)	$ 0.18

Item 8. Financial Statements and Supplementary Data.

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Clean Energy Fuels Corp.:

We have audited the accompanying consolidated balance sheets of Clean Energy Fuels Corp. and subsidiaries (the Company) as of December 31, 2009 and 2010, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2010. In connection with our audits of the consolidated financial statements, we also have audited the related financial statement schedule. We also have audited the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these consolidated financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Clean Energy Fuels Corp. and subsidiaries as of December 31, 2009 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, Clean Energy Fuels Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As indicated in the accompanying *Management's Report on Internal Control Over Financial Reporting*, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of IMW Industries, Ltd. and Northstar (formerly Wyoming Northstar Incorporated, Southstar LLC, and M&S Rental LLC), which constituted 8.4% and 0.3% of total revenues during the year ended December 31, 2010, and 21.0% and 3.0% of total assets as of December 31, 2010, respectively. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of IMW Industries, Ltd. and Northstar.

Effective January 1, 2009, the Company changed its method of accounting for business combinations, and effective January 1, 2010, the Company changed its method of accounting for revenue recognition on transactions with multiple deliverables.

/s/ KPMG LLP

Los Angeles, California
March 10, 2011

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Balance Sheets

(In thousands, except share data)

	December 31, 2009	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 67,087	$ 55,194
Restricted cash	2,500	2,500
Accounts receivable, net of allowance for doubtful accounts of $898 and $702 as of December 31, 2009 and December 31, 2010, respectively	16,340	45,645
Other receivables	8,862	27,280
Inventory, net	6,217	20,483
Prepaid expenses and other current assets	7,394	10,959
Total current assets	108,400	162,061
Land, property and equipment, net	172,183	211,643
Notes receivable and other long-term assets	8,186	15,059
Investments in other entities	10,537	10,748
Goodwill	21,572	71,814
Intangible assets, net of accumulated amortization	34,921	112,174
Total assets	$ 355,799	$ 583,499
Liabilities and Stockholders' Equity		
Current liabilities:		
Current portion of long-term debt and capital lease obligations	$ 2,439	$ 22,712
Accounts payable	14,775	28,635
Accrued liabilities	9,696	28,137
Deferred revenue	2,691	17,507
Total current liabilities	29,601	96,991
Long-term debt and capital lease obligations, less current portion	9,782	41,704
Other long-term liabilities	36,040	28,588
Total liabilities	75,423	167,283
Commitments and contingencies (Note 11)		
Stockholders' equity:		
Preferred stock, $0.0001 par value. Authorized 1,000,000 shares; issued and outstanding no shares	—	—
Common stock, $0.0001 par value. Authorized 149,000,000 shares; issued and outstanding 59,840,151 shares and 69,610,098 shares at December 31, 2009 and December 31, 2010, respectively	6	7
Additional paid-in capital	424,581	569,202
Accumulated deficit	(149,410)	(151,926)
Accumulated other comprehensive income (loss)	2,012	(3,996)
Total Clean Energy Fuels Corp. stockholders' equity.	277,189	413,287
Noncontrolling interest in subsidiary	3,187	2,929
Total stockholders' equity	280,376	416,216
Total liabilities and stockholders' equity	$ 355,799	$ 583,499

See accompanying notes to consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Statements of Operations

(In thousands, except share and per share data)

	Years Ended December 31, 2008	2009	2010
Revenue:			
Product revenues	$ 120,161	$ 116,635	$ 189,836
Service revenues	5,706	14,868	21,998
Total revenue	125,867	131,503	211,834
Operating expenses:			
Cost of sales:			
Product cost of sales	97,015	76,766	132,911
Service cost of sales	1,753	6,155	8,978
Derivative losses (gains):			
Futures contracts	611	—	—
Series I warrant valuation	—	17,367	(10,278)
Selling, general and administrative	62,416	47,509	63,258
Depreciation and amortization	9,624	16,992	22,487
Total operating expenses	171,419	164,789	217,356
Operating loss	(45,552)	(33,286)	(5,522)
Interest income (expense), net	1,630	(32)	(1,194)
Other income (expense), net	(168)	(310)	2,080
Income (loss) from equity method investments	(188)	244	427
Loss before income taxes	(44,278)	(33,384)	(4,209)
Income tax (expense) benefit	(290)	(304)	1,436
Net loss	(44,568)	(33,688)	(2,773)
Loss of noncontrolling interest	105	439	257
Net loss attributable to Clean Energy Fuels Corp.	$ (44,463)	$ (33,249)	$ (2,516)
Loss per share:			
Basic and diluted	$ (0.98)	$ (0.60)	$ (0.04)
Weighted average common shares outstanding:			
Basic and diluted	45,367,991	55,021,961	62,549,311

See accompanying notes to consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss)

(In thousands, except share data)

	Common stock		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest in Subsidiary	Total Stockholders' Equity	Total Comprehensive Income (Loss)
	Shares	Amount						
Balance, December 31, 2007	44,274,375	$ 4	$297,867	$ (69,086)	$ 2,148	$ —	$230,933	
Issuance of common stock upon exercise of options	87,414	—	351	—	—	—	351	
Issuance of common stock in exchange for services	2,984	—	30	—	—	—	30	
Issuance of common stock to Boone Pickens	319,488	—	4,999	—	—	—	4,999	
Issuance of common stock in Unit offering, net of offering costs (see note 9)	4,419,192	1	19,072	—	—	—	19,073	
Issuance of Series I warrant, net of offering costs (see note 9)	—	—	9,762	—	—	—	9,762	
Issuance of Series II warrants, net of offering costs (see note 9)	—	—	3,651	—	—	—	3,651	
Cashless exercise of Series II warrants (see note 9)	1,134,759	—	—	—	—	—	—	
Acquisition of noncontrolling interest in DCE	—	—	—	—	—	3,625	3,625	
Stock-based compensation	—	—	10,735	—	—	—	10,735	
Net loss	—	—	—	(44,463)	—	—	(44,463)	$(44,463)
Unrealized loss on futures contracts	—	—	—	—	(654)	—	(654)	(654)
Foreign currency translation adjustment	—	—	—	—	(640)	—	(640)	(640)
Balance, December 31, 2008	50,238,212	5	346,467	(113,549)	854	3,625	237,402	(45,757)
Issuance of common stock upon exercise of options	171,939	—	588	—	—	—	588	
Issuance of common stock, net of offering costs (see note 9)	9,430,000	1	73,217	—	—	—	73,218	
Adoption of FASB ASC 815, Series I warrants	—	—	(9,762)	(2,612)	—	—	(12,374)	
Stock-based compensation	—	—	14,071	—	—	—	14,071	
Net loss	—	—	—	(33,249)	—	(439)	(33,688)	(33,688)
Unrealized gain on futures contracts	—	—	—	—	814	—	814	814
Foreign currency translation adjustment	—	—	—	—	345	—	345	345
Balance, December 31, 2009	59,840,151	6	424,581	(149,410)	2,013	3,186	280,376	(32,529)
Issuance of common stock upon exercise of options	1,118,827	—	11,049	—	—	—	11,049	
Issuance of common stock, net of offering costs (see note 9)	3,450,000	—	42,562	—	—	—	42,562	
Issuance of common stock upon exercise of Series I warrants	1,183,712	—	17,152	—	—	—	17,152	
Issuance of common stock upon business combinations	4,017,408	1	61,938	—	—	—	61,939	
Stock-based compensation	—	—	11,920	—	—	—	11,920	
Net loss	—	—	—	(2,516)	—	(257)	(2,773)	(2,773)
Unrealized loss on futures contracts	—	—	—	—	(4,231)	—	(4,231)	(4,231)
Foreign currency translation adjustment	—	—	—	—	(1,778)	—	(1,778)	(1,778)
Balance, December 31, 2010	69,610,098	$ 7	$569,202	$(151,926)	$(3,996)	$2,929	$416,216	$ (8,782)

See accompanying notes to consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Statements of Cash Flows

(In thousands)

	Years Ended December 31,		
	2008	2009	2010
Cash flows from operating activities:			
Net loss	$(44,568)	$(33,688)	$ (2,773)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation and amortization	9,624	16,992	22,487
Asset impairments	—	—	2,248
Provision for doubtful accounts and notes	529	(783)	264
Loss on disposal of assets	171	423	181
Derivative (gain) loss	—	17,367	(10,278)
Stock-based compensation expense	10,736	14,071	11,920
Common stock issued in exchange for services	30	—	—
Accretion of notes payable	—	—	1,118
Change in contingent consideration for acquisitions	—	—	(1,184)
Changes in operating assets and liabilities, net of assets and liabilities acquired:			
Accounts and other receivables	11,224	(2,656)	(35,718)
Inventory	(707)	109	(4,882)
Margin deposits on futures contracts	(1,114)	(2,118)	(3,706)
Return (deposits) on LNG trucks	9,318	5,752	285
Prepaid expenses and other assets	(3,401)	(1,298)	(860)
Accounts payable	445	925	999
Accrued expenses and other	5,637	(1,826)	15,863
Net cash provided by (used in) operating activities	(2,076)	13,270	(4,036)
Cash flows from investing activities:			
Purchases of property and equipment	(78,032)	(30,499)	(50,534)
Proceeds from sale of property and equipment	386	60	282
Proceeds from sale of loans receivable	—	3,026	2,418
Purchases of short-term investments	(45,230)	—	—
Maturity or sales of short-term investments	57,710	—	—
Initial note issuance to DCE	(714)	—	—
Acquisitions, net of cash acquired	(19,275)	(10,362)	(20,473)
Investments in other entities	(4,616)	(5,634)	(427)
Restricted cash	(2,500)	—	—
Net cash used in investing activities	(92,271)	(43,409)	(68,734)
Cash flows from financing activities:			
Proceeds from Unit offering (see note 9)	32,484	—	—
Proceeds from exercise of Series I warrants	—	—	11,537
Proceeds from issuance of common stock and exercise of stock options	5,351	73,805	53,611
Proceeds from capital lease obligations and debt instruments	25,239	7,160	200
Proceeds from revolving line of credit	—	—	12,665
Repayment of borrowing under revolving line of credit	—	—	(14,348)
Repayment of capital lease obligations and debt instruments	(380)	(20,023)	(1,050)
Net cash provided by financing activities	62,694	60,942	62,615
Effect of exchange rates on cash and cash equivalents	—	—	(1,738)
Net increase (decrease) in cash	(31,653)	30,803	(11,893)
Cash, beginning of year	67,937	36,284	67,087
Cash, end of year	$ 36,284	$ 67,087	$ 55,194
Supplemental disclosure of cash flow information:			
Income taxes paid	$ 149	$ 334	$ 222
Interest paid, net of $493, $539, and $434 capitalized, respectively	$ 449	$ 1,078	$ 2,251

See accompanying notes to consolidated financial statements.

(1) Summary of Significant Accounting Policies

The Company

Clean Energy Fuels Corp., together with its majority and wholly owned subsidiaries (hereinafter collectively referred to as "Clean Energy" or the "Company"), is engaged in the business of selling natural gas fueling solutions to its customers, primarily in the United States and Canada. Beginning September 7, 2010 through its acquisition of I.M.W. Industries, Ltd. ("IMW"), the Company began selling certain equipment and services internationally. Clean Energy was incorporated in April 2001. In June 2001, the Company acquired certain assets and interests of Pickens Fuel Corp. (a private company owned by Boone Pickens) and BCG eFuels, Inc. (owned by Terasen, Inc. ("Terasen") (formerly BC Gas, Inc.)), and Westport Innovations Inc. ("Westport Innovations") of Vancouver, British Columbia. For accounting purposes, BCG eFuels, Inc. was deemed the acquiring entity in the formation of the Company and was accounted for on a carryover cost basis. On December 31, 2002, the Company acquired all the outstanding membership interests of Blue Energy & Technologies, L.L.C. ("Blue Energy").

Clean Energy has a broad customer base in a variety of markets, including public transit, refuse, airports, and regional trucking. At December 31, 2010, Clean Energy operated, maintained or supplied 224 natural gas fueling locations in Arizona, California, Colorado, District of Columbia, Florida, Georgia, Idaho, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Rhode Island, Texas, Virginia, Washington, and Wyoming within the United States, and in British Columbia and Ontario within Canada. The Company also generates revenue through operation and maintenance ("O&M") agreements with certain customers, through building and selling or leasing natural gas fueling stations to its customers, and through financing its customers' vehicle purchases. In April 2008, the Company opened its first compressed natural gas ("CNG") station in Lima, Peru through the Company's joint venture, Clean Energy del Peru. In August 2008, the Company acquired 70% of the outstanding membership interests of Dallas Clean Energy, LLC ("DCE"). DCE owns a facility that collects, processes and sells renewable biomethane collected from a landfill in Dallas, Texas. On October 1, 2009, the Company acquired 100% of BAF Technologies, Inc. ("BAF"), a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles. On September 7, 2010, the Company acquired 100% of IMW, a company engaged in the manufacturing and servicing of natural gas fueling compressors and related equipment. On December 15, 2010, the Company acquired 100% of Wyoming Northstar Incorporated, Southstar, LLC, and M&S Rental LLC (collectively "Northstar"), a provider of design, engineering, construction and maintenance services for LNG and LCNG fueling stations.

Principles of Consolidation

The consolidated financial statements include the financial statements of Clean Energy and its majority or wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of consolidated financial statements in conformity with U.S. generally accepted accounting principles ("US GAAP") require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and

(In thousands, except share and per share data)

(1) Summary of Significant Accounting Policies (Continued)

liabilities at the date of the consolidated financial statements and revenues and expenses during the reporting period. Actual results could differ from those estimates. Current economic conditions may require the use of additional estimates and these estimates may be subject to a greater degree of uncertainty as a result of the uncertain economy.

Cash and Cash Equivalents

The Company considers all highly liquid investments with maturities of three months or less on the date of acquisition to be cash equivalents.

Fair Value of Financial Instruments

The carrying values of the Company's financial instruments, including cash and cash equivalents, accounts and other receivables, notes receivable, accounts payable, accrued liabilities, capital lease obligations and notes payable approximate fair value.

Inventories

Inventories are stated at the lower of cost or market on a first-in, first out basis. Management's estimate of market includes a provision for slow-moving or obsolete inventory based upon inventory on hand and forecasted demand.

Inventories consisted of the following as of December 31, 2009 and 2010:

	2009	2010
Raw materials and spare parts	$6,217	$17,634
Work in process	—	1,196
Finished goods	—	1,653
Total	$6,217	$20,483

Property and Equipment

Property and equipment are recorded at cost. Depreciation and amortization are recognized over the estimated useful lives of the assets using the straight-line method. The estimated useful lives of depreciable assets are twenty years for LNG liquefaction plant assets, ten years for station equipment and LNG trailers, and three to seven years for all other depreciable assets. Leasehold improvements are amortized over the shorter of their estimated useful lives or related lease terms. Periodically, the Company receives grant funding to assist in the financing of natural gas fueling station construction. The Company records the grant proceeds as a reduction of the cost of the respective asset. Total grant proceeds received were approximately $384, $325, and $831 for the years ended December 31, 2008, 2009 and 2010, respectively.

Long-Lived Assets

The Company reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Recoverability of

(In thousands, except share and per share data)

(1) Summary of Significant Accounting Policies (Continued)

long-lived assets to be held and used is measured by a comparison of the carrying amount of an asset to future net undiscounted cash flows expected to be generated by the asset or asset group. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or the fair value less costs to sell.

During the fourth quarter of 2010, the Company's majority-owned subsidiary, DCE, recorded an impairment charge of $717 related to equipment that was replaced as part of its expansion of the McCommas Bluff landfill in Dallas, Texas.

Goodwill and Intangible Assets

Goodwill represents the excess of costs incurred over the fair value of the net assets of acquired businesses. Goodwill and intangible assets acquired in a business combination and determined to have an indefinite useful life are not amortized. Instead, they are tested for impairment at least annually in accordance with Financial Accounting Standards Board ("FASB") authoritative guidance. When assessing fair value, the Company looks at its projected future cash flows and its market capitalization for its respective operations. To the extent the Company's projected future cash flows do not materialize as planned or its market capitalization goes down, the Company could be forced to take an impairment charge in future periods.

Intangible assets with finite useful lives are amortized over their respective estimated useful lives and reviewed for impairment whenever events or changes in circumstances indicate that the carrying value of the asset may not be recoverable.

During the fourth quarter of 2010, as a result of losing a competitive bid to a customer, the Company recorded an impairment charge of $1,531 related to an intangible asset.

The Company's intangible assets as of December 31, 2009 and 2010 were as follows:

	2009	2010
Technology	$22,671	$ 77,071
Customer relationships	9,100	21,590
Acquired contracts	5,896	13,075
Trademark and tradenames	700	7,400
Non-compete agreements	66	2,126
Total	$38,433	$121,262

Amortization expense for intangible assets was $535, $2,247, and $5,915 for the years ended December 31, 2008, 2009 and 2010, respectively. Accumulated amortization as of December 31, 2009 and 2010 was $3,512 and $9,088, respectively. Estimated amortization expense for the five years succeeding the year ended December 31, 2010 is approximately $9,754, $8,903, $8,766, $8,246, and $8,246, respectively.

(In thousands, except share and per share data)

(1) Summary of Significant Accounting Policies (Continued)

Warranty Liability

The Company records warranty liabilities at the time of sale for the estimated costs that may be incurred under its standard warranty. Changes in the warranty liability are presented in the following tables:

	December 31, 2009	December 31, 2010
Warranty liability at beginning of year	$ —	$1,136
Assumed liability through acquisitions	989	691
Costs accrued for new warranty contracts and changes in estimates for pre-existing warranties	222	782
Service obligations honored	(75)	(271)
Warranty liability at end of year	$1,136	$2,338

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which the liability is incurred or becomes reasonably estimable and if there is a legal obligation to restore or remediate the property at the end of the asset life or at the end of the lease term. All of the Company's fueling and storage equipment is located above-ground. The liability amounts are based upon future retirement cost estimates and incorporate many assumptions such as the costs to restore the property, future inflation rates, and the adjusted risk free rate of interest. When the liability is initially recorded, the Company capitalizes the cost by increasing the related property and equipment balance. Over time, the liability is increased and expense is recognized for the change in present value, and the initial capitalized cost is depreciated over the useful life of the asset.

The following table summarizes the activity of the asset retirement obligation, of which $835 and $939 is included in other long-term liabilities, with the remaining current portion included in accrued liabilities, as of December 31, 2009 and 2010, respectively:

	2009	2010
Beginning balance	$489	$ 918
Liabilities incurred	393	183
Liabilities settled	(4)	(23)
Accretion expense	40	50
Ending balance	$918	$1,128

Revenue Recognition

The Company recognizes revenue on gas sales and O&M services in accordance with US GAAP, which requires that four basic criteria must be met before revenue can be recognized: (i) persuasive evidence of an arrangement exists; (ii) delivery has occurred and title and the risks and rewards of ownership have been transferred to the customer or services have been rendered; (iii) the price is fixed

(1) Summary of Significant Accounting Policies (Continued)

or determinable; and (iv) collectability is reasonably assured. Applying these factors, the Company typically recognizes revenue from the sale of natural gas at the time fuel is dispensed or, in the case of LNG sales agreements, delivered to the customers' storage facilities. The Company recognizes revenue from O&M agreements as the related services are provided.

In certain transactions with Clean Energy customers, the Company agrees to provide multiple products or services, including construction of and either leasing or sale of a station, providing O&M to the station, and sale of fuel to the customer. The Company evaluates the separability of revenues based on FASB authoritative guidance, which provides a framework for establishing whether or not a particular arrangement with a customer has one or more revenue elements. Prior to 2010, to the extent the Company had objective evidence of the values of the separate elements indentified as part of a contract, the Company allocated the revenue from the contract on a relative fair value basis at the inception of the arrangement. During 2008 and 2009, the Company did not have sufficient objective evidence for its multiple-element arrangements, which generally resulted in the deferral of revenue until the future services are performed. However, in 2010, the Company elected to apply newly issued FASB authoritative guidance that allows it to use a combination of internal and external objective and reliable evidence to develop management's best estimate of the fair value of the undelivered element. If the arrangement contains a lease, the Company uses the existing evidence of fair value to separate the lease from the other elements in the arrangement.

The Company recognizes revenue related to its leasing activities in accordance with FASB authoritative guidance. The Company's existing station leases are sales-type leases, giving rise to profit at the delivery of the leased station. Unearned revenue is amortized into income over the life of the lease using the effective-interest method. For those arrangements, Clean Energy recognizes gas sales and O&M service revenues as earned from the customer on a volume-delivered basis.

The Company typically recognizes revenue on long-term fueling station construction projects where it sells the station to the customer using the completed-contract method. However, IMW and Northstar use the percentage-of-completion method of accounting because the projects are small and the Company has been able to demonstrate that it can reasonably estimate costs to complete. In those circumstances, revenue is recognized as work on a contract progresses, based on costs incurred in relation to total estimated costs to be incurred for a project.

The Company recognizes revenue on biomethane sales and vehicle sales when it transfers title of the gas or vehicle to our customer.

Volumetric Excise Tax Credits ("VETC")

The Company records its VETC credits as revenue in its consolidated statements of operations as the credits are fully refundable and do not need to offset income tax liabilities to be received. VETC revenues for the years ended December 31, 2008, 2009 and 2010, were $17,197, $15,535, and $16,042, respectively. The legislation providing for VETC was reinstated in the fourth quarter of 2010, made retroactive to January 1, 2010 and extended to December 31, 2011.

(1) Summary of Significant Accounting Policies (Continued)

LNG Transportation Costs

The Company records the costs incurred to transport LNG to its customers in the line item cost of sales in the accompanying statements of operations.

Advertising Costs

Advertising costs are expensed as incurred. Advertising costs amounted to $985, $932, and $1,260 for the years ended December 31, 2008, 2009 and 2010, respectively. For the year ended December 31, 2008, the Company also recognized expenses of $18,647 in support of Proposition 10 on the California ballot in November 2008.

Stock-based Compensation

The Company recognizes compensation expense for all stock-based payment arrangements, net of an estimated forfeiture rate, over the requisite service period of the award. For stock options, the Company determines the grant date fair value using the Black-Scholes option-pricing model which requires the input of certain assumptions, including the expected life of the stock-based payment awards, stock price volatility and risk-free interest rates.

Foreign Currency Translation

In accordance with FASB authoritative guidance, the Company uses the local currency as the functional currency of its foreign subsidiary. Accordingly, all assets and liabilities outside the United States are translated into U.S. dollars at the rate of exchange in effect at the balance sheet date. Revenue and expense items are translated at the weighted-average exchange rates prevailing during the period. Net foreign currency translation adjustments are recorded as accumulated other comprehensive income in stockholders' equity.

Foreign currency transactions occur when there is a receivable or payable denominated in other than the respective entity's functional currency. The Company records the changes in the exchange rate for these transactions in the consolidated statements of operations. For the fiscal years ended December 31, 2008, 2009 and 2010, foreign exchange transaction gains and losses were included in other income (expense) and were gains of $9, $2, and $1,902, respectively.

Income Taxes

Income taxes are computed using the asset and liability method. Under this method, deferred income taxes are recognized by applying enacted statutory tax rates applicable to future years to differences between the tax bases and financial reporting amounts of existing assets and liabilities. Valuation allowances are established when it is more likely than not that such deferred tax assets will not be realized.

The Company has a recognition threshold and a measurement attribute for the financial statement recognition and measurement of tax positions taken or expected to be taken in a tax return. For those benefits to be recognized, a tax position must be more likely than not to be sustained upon examination by taxing authorities based on the technical merits of the position. The amount recognized

(In thousands, except share and per share data)

(1) Summary of Significant Accounting Policies (Continued)

is measured as the largest amount of benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefit in income tax expense.

Net Loss Per Share

Basic net loss per share is computed by dividing net loss by the weighted-average number of common shares outstanding during the period. Diluted net loss per share is computed by dividing net loss by the weighted-average number of common shares outstanding and potentially dilutive securities outstanding during the period. Potentially dilutive securities include stock options and warrants. The dilutive effect of stock options and warrants is computed under the treasury stock method. Potentially dilutive securities are excluded from the computations of diluted net loss per share if their effect would be antidilutive.

The following potentially dilutive securities have been excluded from the diluted net loss per share calculations because their effect would have been antidilutive:

	2008	2009	2010
Stock options	8,234,467	10,348,188	10,433,551
Warrants	18,314,394	18,314,394	17,130,682

Derivative Financial Instruments

The Company, in an effort to manage its natural gas commodity price risk exposures related to certain contracts, utilizes derivative financial instruments. The Company, from time to time, enters into natural gas futures contracts that are over-the-counter swap transactions that convert its index-based gas supply arrangements to fixed price arrangements. The Company accounts for its derivative instruments in accordance with FASB authoritative guidance for derivative instruments and hedging activities, which requires the recognition of all derivatives as either assets or liabilities in the consolidated balance sheet and the measurement of those instruments at fair value.

Historically, through June 30, 2008, the Company's derivative instruments have not qualified for hedge accounting under the authoritative guidance. On and after July 1, 2008, the Company entered into futures contracts that did qualify for hedge accounting. The Company's futures contracts at December 31, 2010 are being accounted for as cash flow hedges and are being used to mitigate the Company's exposure to changes in the price of natural gas and not for speculative purposes. At December 31, 2010, all of the Company's futures contracts qualified for hedge accounting.

The counter-party to the Company's derivative transactions is a high credit quality counterparty; however, the Company is subject to counterparty credit risk to the extent the counterparty to the derivatives is unable to meet its settlement commitments. The Company manages this credit risk by minimizing the number and size of its derivative contracts. The Company actively monitors the creditworthiness of its counterparties and records valuation adjustments against the derivative assets to reflect counterparty risk, if necessary. The counter-party is also exposed to credit risk of the Company, which requires the Company to provide cash deposits as collateral.

(1) Summary of Significant Accounting Policies (Continued)

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during the period from transactions and other events and circumstances from non-owner sources. The difference between net income and comprehensive income for the years ended December 31, 2008, 2009, and 2010 was primarily comprised of the Company's foreign currency translation adjustment and unrealized gains (losses) on futures contracts.

Concentration of Credit Risk

Credit is extended to all customers based on financial condition, and collateral is generally not required. Concentrations of credit risk with respect to trade receivables are limited because of the large number of customers comprising the Company's customer base and dispersion across many different industries and geographies. However, certain international customers have historically been slower to pay on trade receivables. Accordingly, the Company continuously monitors collections and payments from its customers and maintains a provision for estimated credit losses based upon its historical experience and any specific customer collection issues that it has identified. In addition, through Export Development Canada, IMW maintains accounts receivable insurance on a substantial portion of its foreign trade receivables, which covers up to 90% of the related outstanding balance. Although such credit losses have historically been within the Company's expectations and the provisions established, the Company cannot guarantee that it will continue to experience the same credit loss rates that it has in the past.

Recently Adopted Accounting Changes and Recently Issued and Adopted Accounting Standards

In October 2009, the FASB issued new authoritative guidance on multi-deliverable revenue arrangements. This guidance establishes requirements that must be met for an entity to recognize revenue from the sale of a delivered item that is part of a multiple-element arrangement when other items have not yet been delivered. One of the previous requirements this guidance amended was that there be objective and reliable evidence of the standalone selling price of the undelivered items, which must be supported by either vendor-specific objective evidence ("VSOE") or third party evidence ("TPE"). This new guidance eliminates the requirement that all undelivered elements have VSOE or TPE before an entity can recognize the portion of an overall arrangement fee that is attributable to items that already have been delivered. In the absence of VSOE or TPE of the standalone selling price for one or more delivered or undelivered elements in a multiple-element arrangement, entities now are required to estimate the selling prices of those elements. The overall arrangement fee will be allocated to each element (both delivered and undelivered items) based on their relative selling prices, regardless of whether those selling prices are evidenced by VSOE or TPE. The Company adopted the new guidance on January 1, 2010. During the year ended December 31, 2010, the Company recognized approximately $276 of gross margin under the previous guidance and $1,636 of gross margin under the new guidance. At December 31, 2010, the Company had deferred revenue of $943 under the previous guidance.

In January 2010, the FASB issued new accounting guidance which intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels, the reasons for the transfers and to present information about

(1) Summary of Significant Accounting Policies (Continued)

purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). The Company has applied the new disclosure requirements as of January 1, 2010. See note 17.

(2) Acquisitions

Natural Gas Fueling Compressors

On September 7, 2010, the Company, acting through certain of its subsidiaries, completed its purchase of the advanced natural gas fueling compressor and related equipment manufacturing and servicing business of IMW. IMW manufactures and services advanced, non-lubricated natural gas fueling compressors and related equipment for the global natural gas fueling market. IMW is headquartered near Vancouver, British Columbia, has a second manufacturing facility near Shanghai, China and has sales and service offices in Bangladesh, Colombia and the United States.

In connection with the closing of the Company's acquisition of IMW, a subsidiary of the Company (the "Acquisition Subsidiary") executed an upfront cash payment of approximately $15,585 (subject to a final working capital adjustment) and issued 4,017,408 shares of the Company's common stock at closing to IMW's shareholder. The issued shares were registered and available for immediate resale by the IMW shareholder. An additional $288 was paid by the Acquisition Subsidiary subsequently when the Chinese regulatory authorities approved the transfer of IMW Compressors (Shanghai) Co. Ltd. to the Acquisition Subsidiary. The Acquisition Subsidiary also issued the following promissory notes (collectively, the "IMW Notes"): (i) a promissory note with a principal amount of $12,500 that was due and payable on January 31, 2011, (ii) a promissory note with a principal amount of $12,500 that is due and payable on January 31, 2012, (iii) a promissory note with a principal amount of $12,500 that is due and payable on January 31, 2013, and (iv) a promissory note with a principal amount of $12,500 that is due and payable on January 31, 2014. Each payment under the IMW Notes will consist of $5,000 in cash and $7,500 in cash and/or shares of the Company's common stock (the exact combination of cash and/or stock to be determined at the Company's option). In addition, pursuant to a security agreement executed at closing, the IMW Notes are secured by a subordinate security interest in IMW. On January 31, 2011, the Company paid $5,000 in cash and issued 601,926 shares to the IMW shareholders to settle the IMW Note due on that date.

IMW's former shareholder may also receive additional contingent consideration based on future gross profits earned by IMW over the next four years. The additional contingent consideration is subject to achieving minimum gross profit targets and will be determined based on a sliding scale that increases at certain gross profit levels. During the four-year period during which these earn-out payments may be made, the former shareholder of IMW will receive between 0 and 23 percent of the gross profit of IMW as additional consideration, up to a maximum of $40,000 in the aggregate (which maximum would be payable if IMW achieves approximately $174,000 in gross profit over the four-year period during which these earn-out payments may be made).

(In thousands, except share and per share data)

(2) Acquisitions (Continued)

The Company accounted for this acquisition in accordance with FASB authoritative guidance for business combinations, which requires the Company to recognize the assets acquired and the liabilities assumed, measured at their fair values as of the date of acquisition. The following table summarizes the allocation of the aggregate purchase price to the fair value of the assets acquired and liabilities assumed:

Current assets	$ 27,149
Property, plant and equipment	2,559
Identifiable intangible assets	81,400
Goodwill	45,049
Total assets acquired	156,157
Liabilities assumed	(25,986)
Total purchase price	$130,171

Management allocated approximately $81,400 of the purchase price to the identifiable intangible assets related to technology, customer relationships, non-compete agreements, and trademarks that were acquired with the acquisition. The fair value of the identifiable intangible assets will be amortized on a straight-line basis over their estimated useful lives ranging from three to twenty years. In addition, management allocated $45,049 to goodwill as part of the acquisition and recorded a contingent liability of $9,300 related to the additional contingent consideration described above. Under FASB authoritative guidance, the Company is required to adjust the value of the contingent consideration for this acquisition in the statement of operations as the value of the obligation changes each reporting period. As of December 31, 2010, the fair value of the contingent consideration was $8,100.

As of March 10, 2011, the purchase price allocation is preliminary and could change materially in subsequent periods. Any subsequent changes to the purchase price allocation that result in material changes to the Company's consolidated financial results will be adjusted retroactively. The final purchase price allocation is pending the consideration of income tax related matters.

The results of operations of IMW have been included in the Company's consolidated financial statements since September 7, 2010.

The following table presents the Company's unaudited pro forma results of operations for the years ended December 31, 2009 and 2010 as if the acquisition had occurred at the beginning of the respective periods. The pro forma financial data for all periods presented include adjustments for the following: (i) elimination of intercompany transactions (ii) recording the additional amortization expense from the identifiable intangible assets (iii) adjusting the estimated tax provision of the pro forma combined results; (iv) US GAAP conversion adjustments and (v) the issuance of the Company's common stock as part of the acquisition. The Company prepared the pro forma financial information for the combined entities for comparative purposes only, and it is not indicative of what actual results

(In thousands, except share and per share data)

(2) Acquisitions (Continued)

would have been if the acquisition had taken place at the beginning of the respective periods, or of future results.

	For the year ended December 31, 2009	For the year ended December 31, 2010
Revenue	$172,322	$249,093
Net (loss)	(38,892)	(7,922)
(Loss) per share:		
Basic and diluted	$ (0.66)	$ (0.12)

For the period from September 7, 2010 through December 31, 2010, IMW contributed approximately $17,795 and $319, respectively, to the Company's revenue and net loss.

Liquefied Natural Gas Station Construction

On December 15, 2010, the Company acquired Northstar, a leading provider of design, engineering, construction and maintenance services for LNG and LCNG fueling stations. The purchase price primarily consisted of a closing cash payment in the amount of $7,414. The remaining consideration consists of five annual payments in the amount of $700 each commencing on the first anniversary of the closing date, and up to $4,000 in retention bonuses to certain key employees to be paid in four annual installments commencing on the first anniversary of the closing date.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed as of December 15, 2010:

Current assets	$ 4,434
Property, plant and equipment	941
Identifiable intangible assets	3,350
Goodwill	5,228
Total assets acquired	13,953
Liabilities assumed	(3,648)
Total purchase price	$10,305

Management allocated $2,250 of the purchase price to the identifiable intangible assets related to non-compete agreements, customer relationships, and backlog. The fair value of these identifiable intangibles will be amortized on a straight-line basis over their estimated useful lives ranging from one to ten years. The Company also allocated $1,100 of the purchase price to trademarks, which management believes has an indefinite useful life. In addition, management allocated $5,228 to goodwill as part of the acquisition. As of March 10, 2011, the purchase price allocation is preliminary and could change materially in subsequent periods. Any subsequent changes to the purchase price allocation that result in material changes to the Company's consolidated financial results will be adjusted retroactively. The final purchase price allocation is pending the consideration of income tax related matters.

(In thousands, except share and per share data)

(2) Acquisitions (Continued)

The results of Northstar's operations have been included in the Company's consolidated financial statements since December 15, 2010. Pro forma financial information has been excluded as Northstar's historical results of operation are immaterial to that of the Company.

Landfill Operation

On August 15, 2008, the Company and Cambrian Energy McCommas Bluff LLC ("Cambrian") formed a joint venture to acquire all of the outstanding membership interests of DCE. DCE owns a facility that collects, processes and sells landfill gas at the McCommas Bluff landfill located in Dallas, Texas. This acquisition enables the Company to participate in the production of pipeline quality renewable biomethane, which may be used as a vehicle fuel.

The Company paid an aggregate of $19,551, including transaction costs, to acquire a 70% interest in DCE. Also as part of the transaction, the Company granted DCE's minority investor an exclusive, non-assignable option to purchase from the Company up to and including a 19% membership interest in DCE. The exercise price of the option is $368 for each 1%, up to $6,992 for the total 19%. The option may be exercised as a whole or in part (but only in 1% increments) during the ten-year period commencing on the date the loan made by the Company to DCE has been repaid in full.

The Company borrowed $18,000 from PlainsCapital Bank ("PCB") to finance the acquisition of its membership interests in DCE. The Company also obtained a $12,000 line of credit from PCB to finance capital improvements of the DCE processing facility pursuant to a loan made by the Company to DCE and to pay certain costs and expenses related to the acquisition and the PCB loan (see note 7).

The Company accounted for this acquisition in accordance with authoritative guidance for business combinations that requires the Company to recognize the assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree at the acquisition date, measured at their fair values as of that date of acquisition. The following table summarizes the allocation of the aggregate purchase price to the fair value of the assets acquired and liabilities assumed, net of Cambrian's non controlling interest, in the DCE acquisition:

Current assets	$ 1,129
Property, plant and equipment	1,822
Identifiable intangible assets	21,811
Total assets acquired	24,762
Current liabilities assumed	(1,481)
Non-controlling interest	(3,730)
Total purchase price	$19,551

The Company allocated approximately $21,811 to the identifiable intangible asset related to the fair value of DCE's landfill gas lease with the City of Dallas that was acquired with the acquisition. The fair value of the identifiable intangible asset will be amortized on a straight-line basis over the remaining life of the lease, approximately 16.5 years at the acquisition date. The results of DCE's operations have been included in the Company's consolidated financial statements since August 15, 2008.

(2) Acquisitions (Continued)

Operating and Maintenance Contracts

In May and June 2009, the Company acquired four compressed natural gas operations and maintenance services contracts for $5,645 in cash. The Company recorded $537 to tangible assets and $5,108 of intangible assets related to customer relationships, which are being amortized over their expected lives of eight years. The results of operations of the acquired contracts are included in the Company's consolidated financial statements from their acquisition dates forward, which are May 2009 for two of the contracts and June 2009 for the remaining two contracts. In addition, as part of the acquisition, the Company became the custodian of certain customer-owned inventories that it is required to replenish when the contracts expire. The customer-owned inventory was valued by the Company's as an asset at $986 with a corresponding balance of $986 recorded as a liability on the acquisition dates of the contracts. During 2010, the Company recorded a charge of $1,531 related to the impairment of an intangible asset originally recorded with this acquisition.

Vehicle Conversion

On October 1, 2009, the Company purchased all the outstanding shares of BAF Technologies, Inc. ("BAF"), under a stock purchase agreement. The Company paid an aggregate of $8,467 to acquire BAF. Pursuant to the terms of the agreement, the purchase price was reduced by the amount of BAF's outstanding debt, which was repaid in full at closing. Due to the fact that approximately $3,790 of BAF's outstanding debt, including interest, was held by a subsidiary of the Company, the Company paid a net amount of approximately $4,717 in cash to acquire BAF at the closing. BAF shareholders will be able to earn additional consideration if BAF achieves certain gross profit targets in fiscal 2011. The additional consideration will be determined as a percentage of gross profit based on a sliding scale that increases at certain gross profit levels, subject to achieving a minimum gross profit target and capped by a maximum additional payment amount. For 2010, the shareholders of BAF will receive between one and twenty-six percent of the gross profit of BAF as additional consideration if BAF achieves $8,000 or more in gross profit, up to a maximum of $11,000 in additional consideration (which maximum amount would be payable if BAF achieved approximately $42,300).

For 2011, the shareholders of BAF will receive between one and twenty-one percent of the gross profit of BAF as additional consideration if BAF achieves $8,500 or more in gross profit, up to a maximum of $11,000 in additional consideration (which maximum amount would be payable if BAF achieved approximately $52,400 in gross profit in 2011). The Company accounted for this acquisition in accordance with authoritative guidance for business combinations, which requires the Company to recognize the assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree at the acquisition date, measured at their fair values as of that date of acquisition. The following table

(In thousands, except share and per share data)

(2) Acquisitions (Continued)

summarizes the allocation of the aggregate purchase price to the fair value of the assets acquired and liabilities assumed:

Current assets	$ 4,820
Property, plant and equipment	158
Identifiable intangible assets	10,660
Goodwill	774
Total assets acquired	16,412
Current liabilities assumed	(4,845)
Total purchase price	$11,567

The Company allocated approximately $10,660 of the purchase price to the identifiable intangible assets related to customer relationships, engine certifications and trademarks that were acquired with the acquisition. The fair value of the identifiable intangible assets will be amortized on a straight-line basis over their estimated useful lives of 1.5 to 8 years. In addition, the Company allocated $774 to goodwill as part of the acquisition and recorded a contingent liability of $3,100 related to the possible consideration owed to BAF shareholders if BAF achieves certain gross profit targets in 2010 and 2011. Under the accounting guidance the Company must follow for this acquisition, the Company is required to adjust the value of the contingent consideration for this acquisition in the statement of operations as the value of the obligation changes each reporting period. At December 31, 2010, the liability for this obligation remained $3,100.

The results of BAF's operations have been included in the Company's consolidated financial statements since October 1, 2009.

(3) Other Receivables

Other receivables at December 31, 2009 and 2010 consisted of the following:

	2009	2010
Loans to customers to finance vehicle purchases	$1,179	$ 1,013
Capital lease receivables	1,210	273
Accrued customer billings	—	1,976
Advances to vehicle manufacturers	2,413	3,603
Fuel tax credits	2,627	17,577
Other	1,433	2,838
	$8,862	$27,280

(In thousands, except share and per share data)

(4) Land, Property and Equipment

Land, property and equipment at December 31, 2009 and 2010 are summarized as follows:

	2009	2010
Land	$ 473	$ 1,198
LNG liquefaction plants	91,831	92,856
Station equipment	83,935	91,492
LNG trailers	11,887	12,020
Other equipment	15,744	24,478
Construction in progress	14,191	53,386
	218,061	275,430
Less accumulated depreciation	(45,878)	(63,787)
	$172,183	$211,643

(5) Investment in Other Entities

Through December 31, 2010, the Company has invested approximately $10,427 in The Vehicle Production Group LLC ("VPG"), a company that is developing a natural gas vehicle made in the United States for taxi and paratransit use. In February 2011, the Company invested $1,564 of additional funds in VPG. The Company accounts for its investment in VPG under the cost method of accounting as the Company does not have the ability to exercise significant influence over VPG's operations.

(6) Accrued Liabilities

Accrued liabilities at December 31, 2009 and 2010 consisted of the following:

	2009	2010
Salaries and wages	$2,556	$ 2,218
Accrued gas and equipment purchases	628	6,995
Derivative liability	—	3,060
Accrued refund of tax credits	—	880
Contingent consideration obligations	—	3,493
Accrued property and other taxes	2,384	3,999
Accrued professional fees	577	670
Accrued employee benefits	777	1,659
Accrued warranty liability	1,136	2,338
Other	1,638	2,825
	$9,696	$28,137

(7) Long-term Debt

In conjunction with the Company's acquisition of its 70% interest in Dallas Clean Energy, LLC ("DCE"), on August 15, 2008, the Company entered into a credit agreement ("Credit Agreement") with PlainsCapital Bank ("PCB"). The Company borrowed $18,000 (the "Facility A Loan") to finance

(7) Long-term Debt (Continued)

the acquisition of its membership interests in DCE. The Company also obtained a $12,000 line of credit from PCB to finance capital improvements of the DCE processing facility and to pay certain costs and expenses related to the acquisition and the PCB loans (the "Facility B Loan").

On October 7, 2009, the Facility A Loan was repaid in full and converted into a $20,000 line of credit (the "A Line of Credit") pursuant to an amendment to the Credit Agreement. On August 13, 2010, the Credit Agreement was amended to extend the maturity date of the A Line of Credit to August 14, 2011 and add an unused facility fee. The amendment also provides for a 1-year option to extend the maturity date to August 14, 2012, subject to the Company not being in default on the A Line of Credit. The unused facility fees are to be paid quarterly, in an amount equal to one-tenth of one percent (0.10%) of the unused portion. As of December 31, 2010, the Company did not have any amounts outstanding under the A Line of Credit.

The principal amount of the Facility B Loan became due and payable in annual payments commencing on August 1, 2009, and continuing each anniversary date thereafter, with each such payment being in an amount equal to the lesser of twenty percent of the aggregate principal amount of the Facility B Loan then outstanding or $2,800. Pursuant to an amendment to the Facility B loan between the Company and PCB dated November 1, 2010, PCB agreed to forgo the scheduled payment due from the Company on August 2010 in the amount of $2,059 until January 31, 2011. As of December 31, 2010, the Company had an outstanding balance of $9,909 under the Facility B Loan. Any amount of unpaid principal and interest outstanding on the Facility B Loan is due and payable on August 15, 2013.

Interest accrues daily on the amounts outstanding under the Credit Agreement at the greater of the prime rate of interest for the United States plus 0.50% per annum, or 5.50% per annum. The Company paid a facility fee of $300 in connection with the Credit Agreement. As of December 31, 2010, the unamortized balance of the facility fee was $158. Amortization of the facility fee is recorded as additional interest expense in the consolidated statements of operations.

The Credit Agreement requires the Company to comply with certain covenants. The Company may not incur indebtedness or liens except as permitted by the Credit Agreement, or declare or pay dividends. The Company must maintain, on a quarterly basis, minimum liquidity of not less than $6,000, accounts receivable balances, as defined, of not less than $8,000, consolidated net worth, as defined, of not less than $150,000, and a debt to equity ratio, as defined, of not more than 0.3 to 1.0. Beginning in the quarter ended June 30, 2009, the Company must also maintain a minimum debt service ratio, as defined, of 1.5 to 1.0 at each quarter end. In computing these amounts, the Company excludes the financial results and amounts of IMW. Effective in the fourth quarter of 2008, the Company established a lock-box arrangement with PCB subject to the Credit Agreement. Funds from the Company's customers are remitted to the lock-box and then deposited to a PCB bank account. The remitted funds are not used to pay-down the balance of the Credit Agreement. However, if the Company defaults on the Credit Agreement, all of the obligations under the Credit Agreement will become immediately due and payable and all funds received in the Company's lock-box held by PCB will be applied to the balance due on the A Line of Credit and the Facility B Loan. One of the events of default is the occurrence of a "material adverse change," which is a subjective acceleration clause. Based on the authoritative guidance for balance sheet classification of borrowings outstanding under revolving credit agreements that include both a subjective acceleration clause and a lock-box

(7) Long-term Debt (Continued)

arrangement, the Company has classified its debt pursuant to the Credit Agreement as short-term or long-term, as appropriate, and believes that the likelihood of an event of default is more than remote, but not more likely than not.

One of the Company's bank covenants is a requirement to maintain accounts receivable balances from certain subsidiaries above $8,000 at each quarter end during the term. Because the Company's revenues are dependent on the price of natural gas and the volume of natural gas the Company delivers, to the extent natural gas prices fall or the Company's volumes decline, the Company could violate this covenant in the future. Beginning with the quarter ended June 30, 2009, the Company is required to maintain a debt service ratio, as defined, of not less than 1.5 to 1.0. To the extent the Company's operating results do materialize as planned, the Company could violate this covenant in the future. As of December 31, 2010, the Company was in compliance with its covenants. The Credit Agreement is secured by the Company's interest in, and note receivable from, DCE (described below), certain of the Company's accounts receivable and inventory balances and 45 of the Company's LNG tanker trailers. The net book value of the collateral securing the PCB loans was approximately $65,017 at December 31, 2010. The Company maintains $2,500 in a payment reserve account at PCB. PCB may, in the event of a default, withdraw funds from the account to apply to the principal and interest payments due on the A Line of Credit or the Facility B Loan. Such amount is included as restricted cash in the Company's consolidated balance sheet at December 31, 2010.

In conjunction with the DCE acquisition mentioned above, the Company also entered into a Loan Agreement with DCE (the "DCE Loan") to provide secured financing of up to $14,000 to DCE for future capital expenditures or other uses as agreed to by the Company, in its sole discretion. As of December 31, 2010, the Company is owed approximately $11,200 under the DCE Loan. Interest on the unpaid balance accrues at a rate of 12% per annum and became payable quarterly beginning on September 30, 2008. The principal amount of the loan is due and payable in annual payments commencing on August 1, 2009, and continuing each anniversary date thereafter, with each such payment being in an amount equal to the lesser of the aggregate principal amount of the DCE Loan then outstanding or $2,800. As referenced above, PCB agreed to forgo the Company's Facility B Loan payment due in August 2010 in the amount of $2,059 until January 31, 2011, which payment was made on such date. The Company granted an additional extension to DCE for the payment due January 31, 2011 to March 31, 2011. On August 1, 2013, the entire amount of unpaid principal and interest under the DCE Loan is due and payable.

The principal and accrued interest balances, as well as any interest income related to the DCE Loan, are eliminated in the consolidated financial statements of the Company. Any event of default by DCE on the DCE Loan results in a cross-default of the Company's Credit Agreement with PCB. Events of default include failure to make payments when due, DCE's failure to perform under the provisions of its landfill lease with the City of Dallas, DCE's violation of a covenant under its operating agreement and other standard events of default.

In connection with the closing of the Company's acquisition of IMW, the Company issued the IMW Notes (see note 2).

Also in connection with the closing of the Company's acquisition of IMW, the Company entered into an Assumption Agreement (the "Assumption Agreement") with HSBC Bank Canada ("HSBC")

(7) Long-term Debt (Continued)

pursuant to which the Company assumed the obligations and liabilities of IMW under the following arrangements with HSBC (collectively, the "IMW Lines of Credit"):

(i) An operating line of credit with a limit of $7,750 in Canadian dollars ("CAD") bearing interest at prime plus 1.25%, to assist in financing the day-to-day working capital needs of IMW.

(ii) A bank guarantee line with a limit of CAD$3,000, which allows IMW to provide guarantees and/or standby letters of credit to overseas suppliers or bid/performance deposits on contracts.

(iii) A forward exchange contract line with a limit of CAD$13,750. The forward exchange contract line allows IMW to enter into foreign exchange forward contracts up to the notional limit of CAD$13,750 (no forward exchange contracts were outstanding at December 31, 2010).

(iv) A MasterCard limit with a maximum amount of CAD$150.

(v) An operating line of credit with a limit of 4,000 Renminbi ("RMB") (CAD$593) bearing interest at the 6 month People's Bank of China rate plus 2.5%.

(vi) A bank guarantee line with a limit of 1,000 RMB (CAD$148).

(vii) A 16,750 Bengali Taka (CAD$239) operating line of credit bearing interest at 14%.

(viii) A 320,000 Columbian Peso (CAD$166) operating line of credit bearing interest at the Colombia benchmark rate plus 7 to 9%.

The IMW Lines of Credit are secured by a general security agreement providing a first priority security interest in all present and after acquired personal property of IMW, including specific charges on all serial numbered goods, inventory and other assets and assignment of risk insurance (the "Security"). The IMW Lines of Credit contain no fixed repayment terms or mandatory principal payments and are due on demand. Based on the relevant accounting guidance, we have classified this debt pursuant to the credit agreement as short-term given that it is due on demand.

The Assumption Agreement with HSBC also includes certain financial covenants. Among these financial covenants are that IMW shall not permit: 1) its ratio of debt to tangible net worth to be greater than 3.25 to 1.0 until December 31, 2010 and greater than 3.0 to 1.0 on or after January 1, 2011, 2) its tangible net worth to at anytime be below CAD$3,000 and 3) its ratio of current assets to current liabilities to be less than 1.15 to 1.0 until December 31, 2010 and less than 1.25 to 1.0 on or after January 1, 2011. IMW was in compliance with the financial covenants as of December 31, 2010.

In addition, the Company and IMW agreed that should the making of any scheduled payment by IMW to the seller of IMW under the IMW Notes result in IMW being in breach of the Assumption Agreement, the IMW Lines of Credit or the Security, the Company shall furnish IMW with the funds needed to remain in compliance with the Assumption Agreement, the IMW Lines of Credit and the Security. Further, the Company and IMW agreed that should IMW make any future earn-out payments to the seller of IMW in connection with the acquisition of IMW, and should the making of such earn-out payments result in IMW being in breach of the Assumption Agreement, the IMW Lines of Credit or the Security, then the Company shall furnish IMW with the funds needed to make such

(In thousands, except share and per share data)

(7) Long-term Debt (Continued)

earn-out payments and remain in compliance with the Assumption Agreement, the IMW Lines of Credit and the Security.

In connection with the closing of the Company's acquisition of Northstar, the Company issued notes payable as described in note 2.

Long-term debt at December 31, 2009 and 2010 consisted of the following:

	December 31, 2009	December 31, 2010
Facility B loan	$10,047	$ 9,909
IMW future payment notes	—	44,568
Northstar future payments	—	2,900
DCE notes	—	435
IMW assumed debt	—	4,626
Capital lease obligations	2,174	1,978
Total debt and capital lease obligations	12,221	64,416
Less amounts due within one year and short-term borrowings	(2,439)	(22,712)
Total long-term debt and capital lease obligations	$ 9,782	$ 41,704

The following is a summary of aggregate maturities of long-term debt for each of the years ending December 31:

	2011	2012	2013	2014	2015
Facility B loan	$ 4,252	$ 1,926	$ 3,731	$ —	$ —
IMW future payment notes	12,426	11,559	10,704	9,879	—
Northstar future payments	665	625	583	538	489
DCE notes	285	150	—	—	—
IMW assumed debt	4,578	48	—	—	—
Capital lease obligations	506	469	484	233	286
Total	$22,712	$14,777	$15,502	$10,650	$775

(In thousands, except share and per share data)

(8) Derivative Transactions

The Company marks to market its open futures positions at the end of each period and records the net unrealized gain or loss during the period in derivative (gains) losses in the consolidated statements of operations or in accumulated other comprehensive income in the consolidated balance sheets in accordance with the applicable accounting guidance. The Company recorded unrealized (gains) losses of $654, ($814), and $4,231, in other comprehensive income (loss) in the years ended December 31, 2008, 2009 and 2010 related to its futures contracts. Of the $4,071 liability for the Company's future contracts at December 31, 2010, $3,060 is included in accrued liabilities for the short-term amount, and $1,011 is included in other long-term liabilities for the long-term amount in the Company's consolidated balance sheet as of December 31, 2010. Of the asset for the Company's futures contracts of $159 as of December 31, 2009, an asset of $442 is included in prepaid expenses and other current assets for the short-term amount, and a liability of $283 is included in other long-term liabilities for the long-term amount in the Company's consolidated balance sheet. The Company's ineffectiveness related to its futures contracts in the year ended December 31, 2009 and 2010 were insignificant. During the years ended December 31, 2009 and 2010, the Company recognized cost of sales of $1,834 and $1,781, in the accompanying consolidated statement of operations related to its futures contracts that were settled during the years.

The following table presents the notional amounts and weighted average fixed prices per gasoline gallon equivalent of the Company's natural gas futures contracts as of December 31, 2010:

	Gallons	Weighted Average Price Per Gasoline Gallon Equivalent
2011	11,600,000	$0.82
2012	5,160,000	0.81
January to May, 2013	300,000	0.81

(9) Stockholders' Equity

Authorized Shares

The Company's certificate of incorporation authorizes the issuance of two classes of capital stock designated as common stock and preferred stock, each having $0.0001 par value per share. As of December 31, 2010, the Company was authorized to issue 150,000,000 shares, of which 149,000,000 shares are designated common stock and 1,000,000 shares are designated preferred stock.

Dividend Provisions

The Company did not declare nor pay any dividends during the years ended December 31, 2008, 2009 or 2010.

Voting Rights

Each holder of common stock has the right to one vote per share owned on matters presented for stockholder action.

(9) Stockholders' Equity (Continued)

Issuance of Common Stock

On July 1, 2009, the Company closed a follow-on public offering of 9,430,000 shares of common stock at a price of $8.30 per share. The aggregate amount of common shares sold reflects the exercise in full by the underwriters of their option to purchase 1,230,000 additional shares of the Company's common stock. The Company received aggregate net proceeds of $73,218, after deducting underwriting discounts and commissions and estimated offering expenses payable by the Company.

On November 11, 2010, the Company issued 3,450,000 shares of common stock at a price of $13.25 per share, including 50,068 shares purchased by key executives of the Company, and the exercise in full by the underwriters of their option to purchase 450,000 additional shares of the Company's common stock. The purchase price paid by the key executives of the Company was $14.48 per share, which was the consolidated closing bid price of the Company's common stock on the NASDAQ Global Market on November 10, 2010. The Company received aggregate net proceeds of $42,562 after deducting underwriting discounts and commissions and offering expenses payable by the Company.

Issuance of Common Stock and Warrants

On October 28, 2008, the Company entered into a Placement Agent Agreement (the "Placement Agent Agreement") relating to the sale and issuance by the Company to select investors of 4,419,192 units (the "Units"), with each Unit consisting of (i) one share of the Company's common stock, par value $0.0001 per share, (ii) a warrant to purchase 0.75 shares of Common Stock (the "Series I Warrant"), and (iii) one warrant to purchase up to 0.2571 shares of Common Stock (the "Series II Warrant"). The price of each Unit was $7.92 per Unit. The transaction closed on November 3, 2008, and the Company issued 4,419,192 shares of common stock, Series I Warrants to purchase up to 3,314,394 shares of Common Stock, and Series II Warrants to purchase up to 1,136,364 shares of Common Stock. The Company received approximately $32,484 after deducting the placement agent's fees and other offering expenses related to the Unit sale. The proceeds of $32,484 were allocated between the common stock, the Series I Warrants and the Series II Warrants. The Company allocated $19,166, $9,745 and $3,573 to the common stock, the Series I Warrants and the Series II Warrants, respectively.

The Series I Warrants became exercisable beginning six months from the date of issuance for a period of seven years from the date they become exercisable, and carry an exercise price of $12.68 per share. On November 10, 2010, the Company entered into an amendment with one of the holders of the Series I warrants pursuant to which the expiration date of such warrant for the purchase of 1,183,712 shares of common stock was changed to November 10, 2010. In consideration of the modification to the expiration date, the Company agreed to pay the holder of such warrant approximately $3,172. The Company received notice on November 10, 2010 that such warrant was being exercised in full, and issued 1,183,712 shares of its common stock for an aggregate exercise price of approximately $15,009. Upon exercise, the Company recognized a gain of approximately $3,208 related to the transaction. For additional information on the Series I Warrants see note 17.

The Series II Warrants became exercisable on November 5, 2008 upon the failure of the California Alternative Fuel Vehicles and Renewable Energy Act, or Proposition 10, in the California statewide election. The Series II Warrants were all exercised on a cashless basis at the exercise price of $0.01 per

(In thousands, except share and per share data)

(9) Stockholders' Equity (Continued)

share, which resulted in the issuance of 1,134,759 shares of common stock to the Series II Warrant holders on November 12, 2008.

Stock Option Plans

In December 2002, the Company adopted its 2002 Stock Option Plan ("2002 Plan"). The board of directors determines eligibility, vesting schedules, and exercise prices for options granted under the 2002 Plan. Options generally have a term of ten years.

Under the 2002 Plan, eligible persons may be issued options for services rendered to the Company. Under the 2002 Plan, the purchase price per share for each option granted shall not be less than 100% of the fair market value of the Company's common stock on the date of such option grant; provided, however, that the purchase price per share of common stock issued to a 10% stockholder shall not be less than 110% of such fair market value on the date of such option grant. Options generally vest over a three-year period.

In December 2006, the Company adopted its 2006 Equity Incentive Plan ("2006 Plan"). The 2006 Plan was effective on May 24, 2007, the date the Company completed its initial public offering of common stock. Under the 2006 Plan, 6,390,500 shares of common stock were initially authorized for issuance, and on January 1, 2007, 2008, 2009 and 2010, this number was automatically increased by 1,000,000 shares at each date in accordance with the terms of the 2006 Plan. During 2009, the shareholders of the Company approved an additional increase of 1,500,000 authorized shares for issuance under the 2006 Plan. The 2002 Plan became unavailable for new awards upon the effectiveness of the 2006 Plan. If any outstanding option under the 2002 Plan expires or is cancelled, the shares allocable to the unexercised portion of that option will be added to the share reserve under the 2006 Plan and will be available for grant under the 2006 Plan. As of December 31, 2010, the Company had 11,890,500 shares reserved for issuance in total under the 2006 Plan. At December 31, 2010, the Company had 21,555 shares available for grant under the 2006 Plan.

Option activity for the year ended December 31, 2010 is as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding, December 31, 2009	10,348,188	$ 9.57		
Options granted	1,592,600	14.39		
Options exercised	(1,118,827)	9.88		
Options forfeited	(388,410)	14.62		
Outstanding, December 31, 2010	10,433,551	10.09	7.0	$39,138
Exercisable, December 31, 2010	6,952,247	$ 9.33	6.1	$31,372

As of December 31, 2010, there was $24,988 of total unrecognized compensation cost related to non-vested shares. That cost is expected to be recognized over a weighted average period of 1.7 years. The total fair value of shares vested during the year ended December 31, 2010 was $12,216.

(In thousands, except share and per share data)

(9) Stockholders' Equity (Continued)

All of the Company's unvested options issued prior to October 2005 vested in October 2005 when the Company experienced a change in control in accordance with the 2002 Plan. The Company plans to issue new shares to its employees upon the employee's exercise of their options. The intrinsic value of all options exercised during 2008, 2009 and 2010 was $600, $1,700, and $4,435, respectively.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following assumptions used for grants during the year ended December 31, 2010:

Dividend yield	0.00%
Expected volatility	76.04% to 84.00%
Risk-free interest rate	1.73% to 2.74%
Expected life in years	6.0

The weighted-average grant date fair value of options granted during the years ended December 31, 2008, 2009, and 2010, were $4.89, $7.07, and $10.17, respectively. The volatility amounts used during the year were estimated based on several comparable companies. The expected lives used during the year were based on the weighted average of the vesting periods averaged with the term of the respective options. The risk free rates used during the year were based on the U.S. Treasury yield curve at the time of grant. The Company recorded $10,736, $14,071, $11,920 of stock option expense during the years ended December 31, 2008, 2009 and 2010, respectively. The Company has not recorded any tax benefit related to its stock option expense.

Boone Pickens Warrant Agreement

On December 28, 2006, the Company issued to Boone Pickens a five-year warrant to purchase 15,000,000 shares of the Company's common stock at an exercise price of $10.00 per share.

(10) Income Taxes

The components of income (loss) before income taxes for the years ended December 31, 2008, 2009, and 2010 are as follows:

	2008	2009	2010
U.S.	$(42,996)	$(32,651)	$(5,791)
Foreign	(1,177)	(294)	1,839
	$(44,173)	$(32,945)	$(3,952)

(In thousands, except share and per share data)

(10) Income Taxes (Continued)

The provision (benefit) for income taxes consists of the following:

	2008	2009	2010
Current:			
State	$ 261	$ 304	$ 255
Federal	28	—	(1,753)
Foreign	—	—	117
Total current	289	304	(1,381)
Deferred:			
State	(1,242)	(756)	(966)
Federal	(5,932)	(4,502)	(4,361)
Foreign	(375)	724	145
Change in valuation allowance	7,549	4,534	5,127
Total deferred	—	—	(55)
Total	$ 289	$ 304	$(1,436)

Income tax expense (benefit) for the years ended December 31, 2008, 2009 and 2010 differs from the "expected" amount computed using the federal income tax rate of 34% as a result of the following:

	2008	2009	2010
Computed expected tax expense (benefit)	$(13,793)	$(11,201)	$(1,344)
State and local taxes, net of federal benefit	148	40	169
Nondeductible expenses	8,419	7,481	(2,540)
Tax rate differential on foreign earnings	—	—	(563)
Refund of alternative minimum taxes	—	—	(1,285)
Tax credits	(210)	(1,045)	(850)
Other	(569)	495	(150)
Change in valuation allowance	6,294	4,534	5,127
Total tax expense (benefit)	$ 289	$ 304	$(1,436)

(In thousands, except share and per share data)

(10) Income Taxes (Continued)

Deferred tax assets and liabilities result from differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. The tax effect of temporary differences that give rise to deferred tax assets and liabilities as of December 31, 2009 and 2010 are as follows:

	2009	2010
Deferred tax assets:		
Accrued expenses	$ 791	$ 917
Sales-type leases	546	544
Alternative minimum tax and general business credits	3,195	2,760
Derivative loss	12,281	9,902
Stock option expense	8,231	8,476
Other	741	974
Net operating loss carryforwards	29,409	42,844
Total deferred tax assets	55,194	66,417
Less valuation allowance	(35,992)	(41,119)
Net deferred tax assets	19,202	25,298
Deferred tax liabilities:		
Depreciation and amortization—domestic	(17,675)	(22,858)
Depreciation and amortization—foreign	—	(2,244)
Partnership income	(1,527)	(2,187)
Total deferred tax liabilities	(19,202)	(27,289)
Net deferred tax assets (liabilities)	$ —	$ (1,991)

At December 31, 2010, the Company had federal and state net operating loss carryforwards of approximately $112,000 and $91,300, respectively. The Company's federal net operating loss carryforward will expire beginning in 2026. The Company's state net operating loss carryforwards begin expiring in 2011. The Company also has a foreign net operating loss carryforward of approximately $3,100 at December 31, 2010. Due to the change of ownership provisions of Internal Revenue Code Section 382, utilization of a portion of the Company's net operating loss and tax credit carryforwards may be limited in future periods.

In assessing the realizability of the net deferred tax assets, management considers whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers projected future taxable income and tax planning strategies in making this assessment. As of December 31, 2009 and 2010, the Company provided a valuation allowance of $35,992, and $41,119, respectively, to reduce the net deferred tax assets due to uncertainty surrounding the realizability of these assets. The net change in the valuation allowance for the years ended December 31, 2008, 2009, and 2010 was $7,549, $4,534, and $5,127 respectively, after adjustments between current and deferred taxes.

The Company has made no provision for U.S. income taxes on the earnings of its foreign subsidiaries, as these amounts are intended to be indefinitely reinvested in operations outside the

(In thousands, except share and per share data)

(10) Income Taxes (Continued)

United States. As of December 31, 2010, the cumulative amount of undistributed earnings of the Company's foreign subsidiaries was approximately $4,100. Because of the potential availability of U.S. foreign tax credits, it is not practicable to determine the U.S. federal income tax liability that would be payable if such earnings were not reinvested indefinitely.

On January 1, 2007, the Company adopted certain accounting guidance that clarifies the accounting for uncertain positions. This guidance requires that the Company recognizes the impact of a tax position in its financial statements if the position is more likely than not of being sustained upon examination, based on the technical merits of the position. The impact of the adoption of this guidance was immaterial to the Company's consolidated financial statements. The total amount of unrecognized tax benefits as of December 31, 2009 and 2010 were $100 and $50, respectively, which if recognized, would primarily affect the effective tax rate in future periods.

The following is a tabular reconciliation of the total amounts of unrecognized tax benefits for the years ended December 31, 2009 and 2010:

Unrecognized tax benefit—December 31, 2008	$ 369
Gross (decreases)—tax positions in prior years	(269)
Unrecognized tax benefit—December 31, 2009	100
Gross (decreases)—tax positions in prior years	(50)
Unrecognized tax benefit—December 31, 2010	$ 50

FASB authoritative guidance requires the Company to accrue interest and penalties where there is an underpayment of taxes based on the Company's best estimate of the amount ultimately to be paid. The Company's policy is to recognize interest accrued related to unrecognized tax benefits and penalties as income tax expense. During each of the years ended December 31, 2009 and 2010, the Company accrued $6 of interest. No penalties have been accrued by the Company.

The Company is subject to taxation in the United States and various states and foreign jurisdictions. The Company's tax years for 2005 through 2009 are subject to examination by various tax authorities. The Company is no longer subject to U.S. examination for years before 2005, and state examinations for years before 2006. The Company is currently under audit by the Internal Revenue Service for tax years 2006 through 2008. On July 15, 2010, the IRS sent the Company a letter disallowing approximately $5,073 related to certain claims the Company made from October 1, 2006 to June 30, 2008 under the Volumetric Excise Tax Credit program. The Company believes its claims were properly made and has appealed the IRS's request for payment.

A number of years may elapse before an uncertain tax position is finally resolved. It is often difficult to predict the final outcome or the timing of resolution of any particular uncertain tax position, but the Company believes that its reserves for income taxes reflect the most probable outcomes. The Company adjusts the reserve, as well as the related interest, in light of changing facts and circumstances. Settlement of any particular position would usually require the use of cash and result in the reduction of the related reserve, or there could be a change in the amount of the Company's net operating loss. The resolution of a matter would be recognized as an adjustment to the provision for income taxes and the effective tax rate in the period of resolution. As of December 31, 2010, it is

(10) Income Taxes (Continued)

possible that the Company's liability for uncertain tax positions will be reduced by as much as $50 during the year ended December 31, 2011 as a result of the settlement of tax positions with tax authorities and lapses of statutes of limitations.

(11) Commitments and Contingencies

Environmental Matters

The Company is subject to federal, state, local, and foreign environmental laws and regulations. The Company does not anticipate any expenditures to comply with such laws and regulations which would have a material impact on the Company's consolidated financial position, results of operations, or liquidity. The Company believes that its operations comply, in all material respects, with applicable federal, state, local and foreign environmental laws and regulations.

Litigation, Claims and Contingencies

The Company may become party to various legal actions that arise in the ordinary course of its business. During the course of its operations, the Company is also subject to audit by tax authorities for varying periods in various federal, state, local and foreign tax jurisdictions. Disputes may arise during the course of such audits as to facts and matters of law. It is impossible at this time to determine the ultimate liabilities that the Company may incur resulting from any lawsuits, claims and proceedings, audits, commitments, contingencies and related matters or the timing of these liabilities, if any. If these matters were to be ultimately resolved unfavorably, an outcome not currently anticipated, it is possible that such outcome could have a material adverse effect upon the Company's consolidated financial position or results of operations. However, the Company believes that the ultimate resolution of such actions will not have a material adverse affect on the Company's consolidated financial position, results of operations, or liquidity.

On July 15, 2010, the Internal Revenue Service ("IRS") sent the Company a letter disallowing approximately $5,073 related to certain claims it made from October 1, 2006 to June 30, 2008 under the Volumetric Excise Tax Credit program. The Company believes its claims were properly made and has appealed the IRS's request for payment.

Operating Lease Commitments

The Company leases facilities, including the land for its LNG production plant in Boron, California, and certain equipment under noncancelable operating leases expiring at various dates

(In thousands, except share and per share data)

(11) Commitments and Contingencies (Continued)

through 2038. The following schedule represents the future minimum lease obligations for all noncancelable operating leases as of December 31, 2010:

Fiscal year:	
2011	$ 3,166
2012	2,990
2013	3,121
2014	3,147
Thereafter	10,384
Total future minimum lease payments	$22,808

Rent expense, including variable rent, totaled $2,219, $5,183, and $6,190 for the years ended December 31, 2008, 2009 and 2010, respectively.

Take-or-Pay LNG Supply Contracts

At December 31, 2010, the Company has entered into an LNG supply contract at market prices that contains minimum take or pay provisions over the term of the contract. The contract contains fixed amounts the Company must pay for any shortfall below its minimum volume requirements and also contains a variable charge that is based on the price of natural gas at the beginning and end of the month when a shortfall occurs. The contract expires in June 2011. For the years ended December 31, 2008, 2009 and 2010, the Company paid approximately $13,417, $3,750, and $4,281, respectively, under take-or-pay supply contracts. At December 31, 2010, the fixed commitments under this contract totaled approximately $998 for the year ending December 31, 2011.

Additionally, in October 2007, the Company entered into an LNG sales agreement with Desert Gas Services (formerly known as Spectrum Energy Services, LLC) ("DGS"), to purchase, on a take-or-pay basis over a term of ten years, 45,000 gallons per day of LNG from a plant to be constructed by DGS in Ehrenberg, Arizona, which is near the California border. This obligation began in March 2010, and for the year ended December 31, 2010, the Company paid approximately $4,041 under the take-or-pay supply contract. The contract expires in October 2017. At December 31, 2010, the fixed commitments under this contract totaled approximately $3,058 for each of the years ending December 31, 2011 through December 31, 2016, and $2,549 for the year ended December 31, 2017.

(12) Geographic Information

Several of the Company's functions, including marketing, engineering, and finance are performed at the corporate level. As a result, significant interdependence and overlap exists among the Company's geographic areas. Accordingly, revenue, operating income (loss), and long-lived assets shown for each geographic area may not be the amounts which would have been reported if the geographic areas were independent of one another. Revenue by geographic area is based on where services are rendered and

(In thousands, except share and per share data)

(12) Geographic Information (Continued)

finished goods are sold. Operation income (loss) is based on the location of the entity selling the finished goods or providing the services.

	2008	2009	2010
Revenue:			
United States	$124,847	$130,546	$194,512
Canada	1,020	957	6,158
Other	—	—	11,164
Total revenue	$125,867	$131,503	$211,834
Operating income (loss):			
United States	$(44,426)	$(33,054)	$ (7,251)
Canada	(1,126)	(232)	1,386
Other	—	—	343
Total operating income (loss)	$(45,552)	$(33,286)	$ (5,522)
Long-lived assets:			
United States	$205,625	$237,345	$271,741
Canada	2,047	1,867	133,078
Other	—	—	2,287
Total long-lived assets	$207,672	$239,212	$407,106

The Company's goodwill and intangible assets at December 31, 2008, 2009 and 2010 relate to its United States operations, its BAF operations, IMW operations, and Northstar operations.

(13) 401(k) Plan

The Company has established a savings plan ("Savings Plan") which is qualified under Section 401(k) of the Internal Revenue Code. Eligible employees may elect to make contributions to the Savings Plan through salary deferrals of up to 20% of their base pay, subject to limitations. The Company may make discretionary contributions to the Savings Plan that are subject to limitations. For the years ended December 31, 2008, 2009 and 2010, the Company contributed approximately $188, $377, and $551 of matching contributions to the Savings Plan, respectively.

(14) Supplier Concentrations

During 2008, 2009, and 2010, the Company incurred approximately 13%, 8%, and 9%, respectively, of its natural gas expense related to its LNG sales from Williams Gas Processing Company pursuant to a floating rate purchase contract that includes minimum purchase commitments. In 2010, the Company incurred 30% of its natural gas expense related to its LNG sales from Shell Energy, which supplies the Company's LNG plant in California and DGS's plant in Arizona where the Company has a take or pay obligation. During 2008, 2009 and 2010, the Company incurred approximately 32%, 28%, and 17%, respectively, of its natural gas costs related to its CNG operations from the SoCal Gas Company and San Diego Gas and Electric. Any inability to obtain natural gas in the amounts needed on a timely basis or at commercially reasonable prices could result in interruption of gas deliveries or increases in gas costs, which could have a material adverse effect on the Company's business, financial condition, and results of operations until alternative sources could be developed at a reasonable cost.

(In thousands, except share and per share data)

(15) Capitalized Lease Obligation and Receivables

The Company leases equipment under capital leases with a weighted-average interest rate of 7.3%. At December 31, 2010, future payments under these capital leases are as follows:

2011	$ 671
2012	569
2013	489
2014	266
2015	287
Total minimum lease payments	2,282
Less amount representing interest	(305)
Present value of future minimum lease payments	1,977
Less current portion	(546)
Capital lease obligations, less current portion	$1,431

The value of the equipment under capital lease as of December 31, 2009 and 2010 are $2,943 and $2,943, with related accumulated amortization of $811 and $1,084, respectively.

The Company also leases certain fueling station equipment, including one of the assets leased above under capital lease, to certain customers under sales-type leases at a 10% interest rate. The leases are payable in varying monthly installments through February 2017.

At December 31, 2010, future receipts under these leases are as follows:

2011	$ 319
2012	236
2013	220
2014	220
2015	220
Thereafter	256
Total	1,471
Less amount representing interest	(160)
	$1,311

(16) Fixed Price and Price Cap Sales Contracts Without an Underlying Futures Contracts

From time to time, the Company enters into contracts with various customers, primarily municipalities, to sell LNG or CNG at fixed prices, and prior to January 1, 2007, the Company from time to time also entered into contracts to sell LNG or CNG at prices subject to a price cap. Effective January 1, 2007, the Company no longer offers contracts with a price cap to its customers. The contracts generally range from two to five years. The most significant cost component of LNG and CNG is the price of natural gas. Through June 2008, the Company also may or may not have had a futures contract in place to economically offset the price of natural gas it was selling to its customers on a fixed price basis. For any futures contracts that were in place related to these contracts, they did

(16) Fixed Price and Price Cap Sales Contracts Without an Underlying Futures Contracts (Continued)

not qualify for hedge accounting and they may have been sold and subsequently reestablished over the term of the customer contract.

As part of determining the fixed price or price cap in the contracts, the Company works with its customers to determine their future usage over the contract term. However, the Company's fixed price and price cap customers do not agree to purchase a minimum amount of volume or guarantee their volume of purchases. There is not an explicit volume in the contract as the Company agrees to sell its customers volumes on an "as needed" basis, also known as a "requirements contract." The volume required under these contracts varies each month, and is not subject to any minimum commitments. For U.S. generally accepted accounting purposes, there is not a "notional amount," which is one of the required conditions for a transaction to be a derivative pursuant to the authoritative guidance.

The Company's sales agreements that fix the price or cap the price of LNG or CNG that it sells to its customers are, for accounting purposes, firm commitments, and U.S. generally accepted accounting principles do not require or allow the Company to record a loss until the delivery of the gas and corresponding sale of the product occurs. When the Company enters into these fixed price or price cap contracts with its customers, the price is set based on the prevailing index price of natural gas at that time. However, the index price of natural gas constantly changes, and throughout the term of the contract, the fixed price of the natural gas included in the customer's contract price typically diverges from the corresponding index price of natural gas after the Company enters into the sales contract (with the price of natural gas having historically increased).

Prior to June 2008, from an accounting perspective, during periods of rising natural gas prices, the Company's futures contracts related to these transaction have generally been marked-to-market through the recognition of a derivative asset and a corresponding derivative gain in its statements of operations. However, because the Company's contracts to sell LNG or CNG to its customers at fixed prices or an index-based price that is subject to a fixed price cap are not derivatives for purposes of U.S. generally accepted accounting principles, a liability or a corresponding loss has not been recognized in the Company's statements of operations during these periods of rising natural gas prices for the future commitments under these contracts. As a result, for these situations, the Company's statements of operations do not reflect its firm commitments to deliver LNG or CNG at prices that are below, and in some cases, substantially below, the prevailing market price of natural gas (and therefore LNG or CNG).

(17) Fair Value Measurements

The Company follows the authoritative guidance for fair value measurements with respect to assets and liabilities that are measured at fair value on a recurring basis and nonrecurring basis. Under the standard, fair value is defined as the exit price, or the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The standard also establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs market participants would use in valuing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions about the factors market participants would use in valuing the asset or liability developed based upon the best

(In thousands, except share and per share data)

(17) Fair Value Measurements (Continued)

information available in the circumstances. The hierarchy is broken down into three levels. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities. Level 2 inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and inputs (other than quoted prices) that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability. Categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement.

During the twelve months ended December 31, 2010, the Company's financial instruments consisted of natural gas futures contracts, debt instruments, contingent consideration, and its Series I warrants. The Company uses quoted forward price curves, discounted to reflect the time value of money, to value its natural gas futures contracts. The Company uses projected financial results for the respective entities, discounted to reflect the time value of money, to value its contingent consideration obligations. The fair market value of the Company's debt instruments approximated their carrying values at December 31, 2009 and 2010. The Company uses either a Monte Carlo simulation model or the Black-Scholes model, depending on the current terms, to value the Series I warrants. The Company considers a variety of market data with observable inputs when estimating the expected volatility used in the model. For example, the Company considers the historical volatilities of its competitors, the call option value of convertible bonds of certain peer group entities and the implied volatilities of its exchange traded stock options. The Company also uses the implied volatilities of its short-term (i.e. 3 to 9 month) traded options and extrapolates the data over the remaining term of the Series I warrants, which was approximately 5.8 years as of December 31, 2010. Given the extrapolation beyond the term of the short term exchange traded options is not based on observable market inputs for a significant portion of the remaining term of the warrants, the Series I warrants have been classified as a Level 3 fair value determination in the table below.

The following tables provide information by level for assets and liabilities that are measured at fair value on a recurring basis:

Description	Balance at December 31, 2010	Quoted Prices In Active Markets for Identical Items (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities:				
Natural gas futures contracts	$ 4,071	$ —	$4,071	$ —
Contingent consideration obligations	11,200	—	—	11,200
Series I warrants	14,148	—	—	14,148

(In thousands, except share and per share data)

(17) Fair Value Measurements (Continued)

The following tables provide a reconciliation of the beginning and ending balances of items measured at fair value on a recurring basis in the table above that used significant unobservable inputs (Level 3).

Liabilities: Series I Warrants	2009	2010
Beginning Balance	$12,374	$ 29,741
Total (gain) loss included in earnings	17,367	(10,278)
Issuance of warrants	—	—
Exercise of warrants	—	(5,315)
Transfers In/Out	—	—
Ending Balance	$29,741	$ 14,148

Included in the gain of $10,278 is a gain of $3,208 related to the exercise of the Series I warrants.

Liabilities: Contingent Consideration	2009	2010
Beginning Balance	$ —	$ 3,100
Business combinations	3,100	9,300
Total (gain) loss included in earnings	—	(1,200)
Payments	—	—
Transfers In/Out	—	—
Ending Balance	$3,100	$11,200

There were no long-lived asset impairments for 2009. During the fourth quarter of 2010, the Company recorded an impairment of $1,531 of an acquired operating and maintenance contract lost in a competitive bid to a competitor. In addition, during the fourth quarter of 2010, the Company's subsidiary, DCE, expensed approximately $717 of costs related to equipment that was replaced as part of its expansion of the McCommas Bluff landfill in Dallas, Texas.

(20) Subsequent Events

On January 31, 2011, the Company made the payment on the first IMW Note by paying $5,000 in cash and issuing 601,926 shares of the Company's common stock.

On February 17, 2011, the Company invested an additional $1,564 in VPG.

On February 25, 2011 (the "Closing Date"), the Company paid $1,200 for a 19.9% interest in ServoTech Engineering, Inc. ("ServoTech"), a company who provides design and engineering services for natural gas fueling systems among other services. The Company also has an option to purchase the remaining 81.1% of ServoTech for $2,800 over the 15 month period following the Closing Date.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of disclosure controls and procedures.

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer (our principal executive and principal financial officers, respectively), evaluated the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply its judgment in evaluating the benefits of possible controls and procedures relative to their costs.

Based on management's evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2010, our disclosure controls and procedures are designed at a reasonable assurance level and are effective to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting.

We regularly review our system of internal control over financial reporting and make changes to our processes and systems to improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new, more efficient systems, consolidating activities, and migrating processes.

On September 7, 2010, the Company completed the acquisition of substantially all of the assets of IMW. On December 15, 2010, the Company acquired the ownership interests of Northstar. Subsequent to these acquisitions, the Company began to integrate these businesses into its internal control over financial reporting structure. As such, there have been changes during the quarter associated with the establishment of internal control over financial reporting with respect to IMW and Northstar. As of December 31, 2010, IMW and Northstar have been excluded from management's report of internal control over financial reporting as described below.

There were no other changes in our internal control over financial reporting that occurred during the period covered by this Annual Report on Form 10-K that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over our financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended). Our management assessed the effectiveness of our internal controls over financial reporting as of December 31, 2010. In making its assessment of the effectiveness of our internal controls over financial reporting, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework*. Our management's evaluation excluded the business of our wholly owned subsidiaries, IMW Industries Ltd and Northstar (formerly Wyoming Northstar Incorporated, Southstar LLC and M&S Rental LLC), which constituted 8.4% and 0.3% of our total revenues during the year ended December 31, 2010, and 21.0% and 3.0% of our total assets as of December 31, 2010, respectively. In accordance with the guidance issued by the SEC, companies are allowed to exclude acquisitions from their assessment of internal controls over financial reporting during the first year subsequent to the acquisition. Based on these criteria, our management has concluded that, as of December 31, 2010, our internal control over financial reporting is effective. Our independent registered public accounting firm, KPMG LLP, has issued an audit report on our assessment of our internal control over financial reporting, which is included in Part II, Item 8 of this Form 10-K.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this item is incorporated by reference to the proxy statement for our Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2010.

Item 11. Executive Compensation.

The information required by this item is incorporated by reference to the proxy statement for our 2011 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2010.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this item is incorporated by reference to the proxy statement for our 2011 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2010.

Item 13. Certain Relationships and Related Transactions and Director Independence.

The information required by this item is incorporated by reference to the proxy statement for our 2011 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2010.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated by reference to the proxy statement for our 2011 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2010.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a)(1) **Consolidated Financial Statements.**

The following documents are filed in Part II, Item 8 of this annual report on Form 10-K:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2009 and 2010

Consolidated Statements of Operations for the Years Ended December 31, 2008, 2009 and 2010

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2008, 2009 and 2010

Consolidated Statements of Cash Flows for the Years Ended December 31, 2008, 2009 and 2010

Notes to Consolidated Financial Statements

(a)(2) **Financial Statement Schedules.**

The following financial statement schedule is filed as a part of this annual report on Form 10-K:

Schedule II: Valuation and Qualifying Accounts

All other schedules have been omitted as they are not required, not applicable, or the required information is otherwise included.

	Allowances for Doubtful Trade Receivables	Reserve for Excess and Obsolete Inventory	Allowance for Doubtful Notes Receivables
Balance at December 31, 2007	$ 502	$ 124	$ 1,251
Charges (benefit) to operations	387	105	142
Deductions	(231)	(160)	—
Balance at December 31, 2008	658	69	1,393
Charges (benefit) to operations	334	216	(1,119)
Deductions	(94)	(180)	(58)
Balance at December 31, 2009	898	105	216
Charges (benefit) to operations	264	553	—
Deductions	(460)	(458)	(123)
Balance at December 31, 2010	$ 702	$ 200	$ 93

(a)(3) **Exhibits.**

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
2.1	Purchase and Sale Agreement dated as of May 7, 2009 by and between Clean Energy and Exterran Energy Solutions, L.P.	Filed as Exhibit 2.1 to the Current Report on Form 8-K.	May 11, 2009
2.2	Stock Purchase Agreement dated September 23, 2009, by and among Clean Energy, a California corporation, BAF Technologies, Inc., a Kentucky corporation and All the Shareholders of BAF Technologies, Inc.	Filed as Exhibit 2.4 to the Current Report on Form 8-K.	September 29, 2009
2.3	Asset Purchase Agreement, dated July 1, 2010, among Clean Energy, a California corporation, 0884808 B.C. Ltd., a British Columbia corporation, and 0884810 B.C. Ltd., a British Columbia corporation, on the one hand, and I.M.W. Industries Ltd., a British Columbia corporation, 652322 B.C. Ltd., a British Columbia corporation, Miller Family Trust and Bradley N. Miller, on the other hand.	Filed as Exhibit 2.5 to the Current Report on Form 8-K.	July 6, 2010

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
2.4	Amendment to Asset Purchase Agreement, dated as of September 7, 2010, by and among Clean Energy, a California corporation, 0884808 B.C. Ltd., a British Columbia corporation and a wholly-owned subsidiary of Clean Energy—CA, and Clean Energy Compression Corp, a British Columbia corporation formerly known as 0884810 B.C. Ltd and a wholly-owned subsidiary of Canadian AcqCo, on the one hand, and I.M.W. Industries Ltd., a British Columbia Corporation, B&M Miller Equity Holdings Inc., a successor by amalgamation to 652322 B.C. Ltd., a British Columbia corporation, Bradley N. Miller, Marion G. Miller and Miller Family Trust, on the other hand.	Filed as Exhibit 2.6 to the Current Report on Form 8-K.	September 7, 2010
2.5	Securities Purchase Agreement, dated December 3, 2010, among Clean Energy, a California corporation, Wyoming Northstar Incorporated, a Wyoming corporation, Southstar LLC, a Wyoming limited liability company, M&S Rental, LLC, a Wyoming limited liability company, and the Sellers listed on Schedule I thereto.	Filed as Exhibit 2.7 to the Current Report on Form 8-K.	December 8, 2010
3.1	Restated Certificate of Incorporation.	Filed as Exhibit 3.1 to the Registration Statement on Form S-1, as amended.	March 27, 2007
3.1.1	Restated Certificate of Incorporation, as amended, by the Certificate of Amendment to the Restated Certificate of Incorporation of Registrant dated May 28, 2010.	Filed as Exhibit 3.1.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2010.	August 9, 2010
3.2	Amended and Restated Bylaws.	Filed as Exhibit 3.2 to the Current Report on Form 8-K.	February 23, 2011

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
4.1	Specimen Common Stock Certificate.	Filed as Exhibit 4.1 to the Registration Statement on Form S-1, as amended.	March 27, 2007
4.2	Registration Rights Agreement dated December 31, 2002.	Filed as Exhibit 4.2 to the Registration Statement on Form S-1, as amended.	September 6, 2006
4.3	Amendment No. 1 to Registration Rights Agreement, dated August 8, 2006.	Filed as Exhibit 4.3 to the Registration Statement on Form S-1, as amended.	September 6, 2006
4.4	Amendment No. 2 to Registration Rights Agreement dated May 1, 2007 between the Registrant and the shareholders named therein.	Filed as Exhibit 4.4 to the Registration Statement on Form S-1, as amended.	May 4, 2007
4.5	Form of Warrant to Purchase Common Stock.	Filed as Exhibit 4.5 to the Current Report on Form 8-K.	October 29, 2008
10.1+	2002 Stock Option Plan, Amendment and Form of Stock Option Agreement.	Filed as Exhibit 10.1 to the Registration Statement on Form S-1, as amended.	September 6, 2006
10.2+	Amended & Restated 2006 Equity Incentive Plan.	Filed as Exhibit 10.2 to the Current Report on Form 8-K.	May 19, 2009
10.3	Lease Agreement dated August 12, 1999 between the Registrant and Bixby Office Park Associates, LLC.	Filed as Exhibit 10.3 to the Registration Statement on Form S-1, as amended.	March 27, 2007
10.4	Form of Indemnification Agreement.	Filed as Exhibit 10.4 to the Registration Statement on Form S-1, as amended.	March 27, 2007
10.5+	Amended and Restated 2002 Stock Option Plan dated August 10, 2007.	Filed as Exhibit 99.1 to the Registration Statement on Form S-8.	August 14, 2007
10.6+	Stock Option Agreement dated May 18, 2006 between the Registrant and G. Michael Boswell.	Filed as Exhibit 99.3 to the Registration Statement on Form S-8.	August 14, 2007
10.7+	2006 Equity Incentive Plan—Form of Notice of Stock Option Grant and Stock Option Agreement.	Filed as Exhibit 99.5 to the Registration Statement on Form S-8.	August 14, 2007
10.8	Buyer's Order and Purchase Agreement dated April 12, 2006 between the Registrant and Inland Kenworth, Inc.	Filed as Exhibit 10.11 to the Registration Statement on Form S-1, as amended.	September 6, 2006

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.9	Trading Authorization dated March 23, 2006.	Filed as Exhibit 10.15 to the Registration Statement on Form S-1, as amended.	September 6, 2006
10.10	Investment Advisory Agreement dated July 24, 2006, between the Registrant and BP Capital LP.	Filed as Exhibit 10.20 to the Registration Statement on Form S-1, as amended.	September 6, 2006
10.11†	Purchase and Sale Agreement dated November 3, 2005 among Clean Energy Texas LNG, LLC and the Sellers Named Therein.	Filed as Exhibit 10.21 to the Registration Statement on Form S-1, as amended.	March 27, 2007
10.12†	Ground Lease dated November 3, 2006 among the Registrant, Clean Energy Construction and U.S. Borax, Inc.	Filed as Exhibit 10.25 to the Registration Statement on Form S-1, as amended.	May 24, 2007
10.13	Warrant to Purchase Common Shares dated December 28, 2006 issued by the Registrant to Boone Pickens.	Filed as Exhibit 10.26 to the Registration Statement on Form S-1, as amended.	March 27, 2007
10.14	Obligation Transfer and Securities Purchase Agreement dated December 28, 2006, between the Registrant and Boone Pickens.	Filed as Exhibit 10.27 to the Registration Statement on Form S-1, as amended.	March 27, 2007
10.15	Investment Advisory Agreement dated March 9, 2007 between the Registrant and BP Capital LP.	Filed as Exhibit 10.30 to the Registration Statement on Form S-1, as amended.	March 27, 2007
10.16+	2006 Equity Incentive Plan—Form of Stock Award Agreement.	Filed as Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2008.	May 15, 2008
10.17	Subscription Agreement dated September 24, 2008 between the Registrant and Boone Pickens Interests, Ltd.	Filed as Exhibit 99.1 to the Current Report on Form 8-K.	September 25, 2008
10.18†	LNG Sales Agreement dated October 17, 2007 between the Registrant and Spectrum Energy Services, LLC.	Filed as Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2007.	November 13, 2007
10.19†	LNG Sales Agreement dated July 1, 2008 between the Registrant and Williams Four Corners LLC.	Filed as Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008.	November 14, 2008

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.20	Sixth Amendment to Lease Agreement dated August 1, 2008 among the Registrant, Clean Energy and Bixby Office Park, LLC.	Filed as Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008.	November 14, 2008
10.21+	Amendment No. 1 to Amended and Restated 2002 Stock Option Plan.	Filed as Exhibit 10.36 to the Annual Filing on Form 10-K for the fiscal year ended 2007.	March 19, 2008
10.22	First Amendment to Base Contract for Sale and Purchase of Natural Gas dated November 1, 2008, between the Registrant and Shell Energy North America (US), L.P.	Filed as Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008.	November 14, 2008
10.23	Guaranty dated November 7, 2008, by the Registrant in favor of Shell Energy North America (US), L.P.	Filed as Exhibit 10.5 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008.	November 14, 2008
10.24+	Amended and Restated Employment Agreement dated December 31, 2008, between the Registrant and Andrew J. Littlefair.	Filed as Exhibit 99.1 to the Current Report on Form 8-K.	December 31, 2008
10.25+	Amended and Restated Employment Agreement dated December 31, 2008, between the Registrant and Richard R. Wheeler.	Filed as Exhibit 99.2 to the Current Report on Form 8-K.	December 31, 2008
10.26+	Amended and Restated Employment Agreement dated December 31, 2008, between the Registrant and Mitchell W. Pratt.	Filed as Exhibit 99.3 to the Current Report on Form 8-K.	December 31, 2008
10.27+	Amended and Restated Employment Agreement dated December 31, 2008, between the Registrant and James N. Harger.	Filed as Exhibit 99.4 to the Current Report on Form 8-K.	December 31, 2008
10.28	Credit Agreement among the Registrant, Clean Energy and PlainsCapital Bank.	Filed as Exhibit 99.9 to the Current Report on Form 8-K.	August 21, 2008
10.29	First Amendment to Credit Agreement among the Registrant, Clean Energy and PlainsCapital Bank.	Filed as Exhibit 10.47 to the Annual Filing on Form 10-K for the fiscal year ended 2008.	March 16, 2009

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.30	Second Amendment to Credit Agreement among the Registrant, Clean Energy and PlainsCapital Bank.	Filed as Exhibit 10.48 to the Annual Filing on Form 10-K for the fiscal year ended 2008.	March 16, 2009
10.31	Third Amendment to Credit Agreement among the Registrant, Clean Energy and PlainsCapital Bank.	Filed as Exhibit 10.49 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009.	May 11, 2009
10.32†	Base Contract for Sale and Purchase of Natural Gas between Shell Energy North America (US), LP and Dallas Clean Energy, LLC.	Filed as Exhibit 10.50 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2009.	August 10, 2009
10.33	First Amendment to Loan Agreement among Clean Energy and Dallas Clean Energy, LLC.	Filed as Exhibit 10.51 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2009.	August 10, 2009
10.34	Fourth Amendment to Credit Agreement among the Registrant, Clean Energy and PlainsCapital Bank.	Filed as Exhibit 10.52 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009.	November 9, 2009
10.35†	Fleet Service Agreement between Bachman NGV, Inc. dba BAF Technologies and AT & T Services, Inc. dated February 22, 2008.	Filed as Exhibit 10.54 to the Annual Filing on Form 10-K for the fiscal year ended 2009.	March 10, 2010
10.36†	Amendment No. 1 to the Fleet Service Agreement between Bachman NGV, Inc. dba BAF Technologies and AT & T Services, Inc. dated March 30, 2009.	Filed as Exhibit 10.55 to the Annual Filing on Form 10-K for the fiscal year ended 2009.	March 10, 2010
10.37+	Employment Agreement dated February 17, 2010, between the Registrant and Barclay Corbus.	Filed as Exhibit 99.1 to the Current Report on Form 8-K.	February 18, 2010
10.38	Form of Year 1 Note, issued by Clean Energy Compression Corp. to I.M.W. Industries Ltd.	Filed as Exhibit 10.57 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010
10.39	Form of Future Payment Note, issued by Clean Energy Compression Corp. to I.M.W. Industries Ltd.	Filed as Exhibit 10.58 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.40	Form of Security Agreement between Clean Energy Compression Corp. and I.M.W. Industries Ltd.	Filed as Exhibit 10.59 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010
10.41	Form of Commitment to Provide Funds, between Clean Energy Compression Corp., 0884808 B.C. Ltd., and HSBC Bank Canada.	Filed as Exhibit 10.60 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010
10.42	Form of Commitment to Provide Funds, between Clean Energy Compression Corp., 0884808 B.C. Ltd., and HSBC Bank Canada.	Filed as Exhibit 10.61 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010
10.43	Form of Assumption Agreement, between I.M.W. Industries Ltd., IMW CNG Bangladesh Ltd., IMW Compressor Group (Shanghai) Co. Ltd., IMW Colombia Ltda., Bradley Norman Miller, Marion Miller, B&M Miller Equity Holdings Inc., Clean Energy Compression Corp., Clean Energy, 0884808 B.C. Ltd., and HSBC Bank Canada.	Filed as Exhibit 10.62 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010
10.44	Form of General Security Agreement, between 0884808 B.C. Ltd. and HSBC Bank Canada.	Filed as Exhibit 10.63 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010
10.45	Form of Guarantee, executed by 0884808 B.C. Ltd.	Filed as Exhibit 10.64 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010
10.46	Fifth Amendment to Credit Agreement among the Registrant, Clean Energy and PlainsCapital Bank.	Filed as Exhibit 10.65 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010
10.47	Seventh Amendment to Lease Agreement, dated September 23, 2010, between Clean Energy and BixbyBIT—Bixby Office Park, LLC.	Filed as Exhibit 10.66 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.48	Limited Waiver and Consent, dated October 29, 2010, among the Registrant, Clean Energy and PlainsCapital Bank.	Filed as Exhibit 10.67 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.	November 8, 2010
10.49	Amendment to Warrant Number SI-4, dated November 10, 2010.	Filed as Exhibit 10.68 to the Current Report on Form 8-K.	November 12, 2010
21.1*	Subsidiaries.		
23.1*	Consent of Independent Registered Public Accounting Firm KPMG LLP.		
31.1*	Certification of Andrew J. Littlefair, President and Chief Executive Officer, pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities and Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
31.2*	Certification of Richard R. Wheeler, Chief Financial Officer, pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities and Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
32.1**	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, executed by Andrew J. Littlefair, President and Chief Executive Officer, and Richard R. Wheeler, Chief Financial Officer.		
99.1	Natural Gas Hedge Policy dated May 29, 2008.	Filed as Exhibit 99.1 to the Current Report on Form 8-K.	June 20, 2008

† Portions of this exhibit have been omitted pursuant to a request for confidential treatment and the non-public information has been filed separately with the SEC.

* Filed herewith.

** Furnished herewith.

\+ Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CLEAN ENERGY FUELS CORP.

By: /s/ ANDREW J. LITTLEFAIR

Andrew J. Littlefair
President and Chief Executive Officer

Date: March 10, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ ANDREW J. LITTLEFAIR Andrew J. Littlefair	President, Chief Executive Officer (Principal Executive Officer) and a Director	March 10, 2011
/s/ RICHARD R. WHEELER Richard R. Wheeler	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	March 10, 2011
/s/ WARREN I. MITCHELL Warren I. Mitchell	Chairman of the Board and Director	March 10, 2011
/s/ VINCENT C. TAORMINA Vincent C. Taormina	Director	March 10, 2011
/s/ JOHN S. HERRINGTON John S. Herrington	Director	March 10, 2011
/s/ JAMES C. MILLER III James C. Miller III	Director	March 10, 2011
/s/ BOONE PICKENS Boone Pickens	Director	March 10, 2011
/s/ KENNETH M. SOCHA Kenneth M. Socha	Director	March 10, 2011

CORPORATE INFORMATION

Board of Directors

WARREN I. MITCHELL
Chairman of the Board
Former Chairman
Southern California Gas Company
May 2005

ANDREW J. LITTLEFAIR
June 2001

T. BOONE PICKENS
Chairman
B.P. Capital, L.P.
June 2001

JAMES C. MILLER III
Former Chairman
United States Postal Service
May 2006

JOHN S. HERRINGTON
Former U.S. Secretary
Department of Energy
November 2005

KENNETH M. SOCHA
Senior Managing Director
Perseus, L.L.C.
January 2003

VINCENT C. TAORMINA
Former Chief Executive Officer
Taormina Industries, Inc.
April 2008

Year denotes year of appointment or election to the board of directors.

Management

ANDREW J. LITTLEFAIR
President and
Chief Executive Officer

RICHARD R. WHEELER
Chief Financial Officer

JAMES N. HARGER
Chief Marketing Officer

MITCHELL W. PRATT
Chief Operating Officer
Corporate Secretary

BARCLAY F. CORBUS
Senior Vice President,
Strategic Development

Shareholder Information

For address changes, consolidation, lost or replacement certificates, contact:

TRANSFER AGENT AND REGISTRAR
Computershare Trust Company
250 Royall Street
Canton, MA 02021
800.962.4284

Common Stock

Clean Energy Fuels Corp. is listed on NASDAQ. Ticker symbol: CLNE

At March 7, 2011, Clean Energy Fuels Corp. had approximately 63 stockholders of record, an estimated 52,679 stockholders held in street name, and 70,253,554 shares of common stock outstanding.

Auditors

KPMG LLP
Los Angeles, California

Investor Relations

562.493.7215

Corporate Headquarters

3020 Old Ranch Parkway, Suite 400
Seal Beach, California 90740
562.493.2804

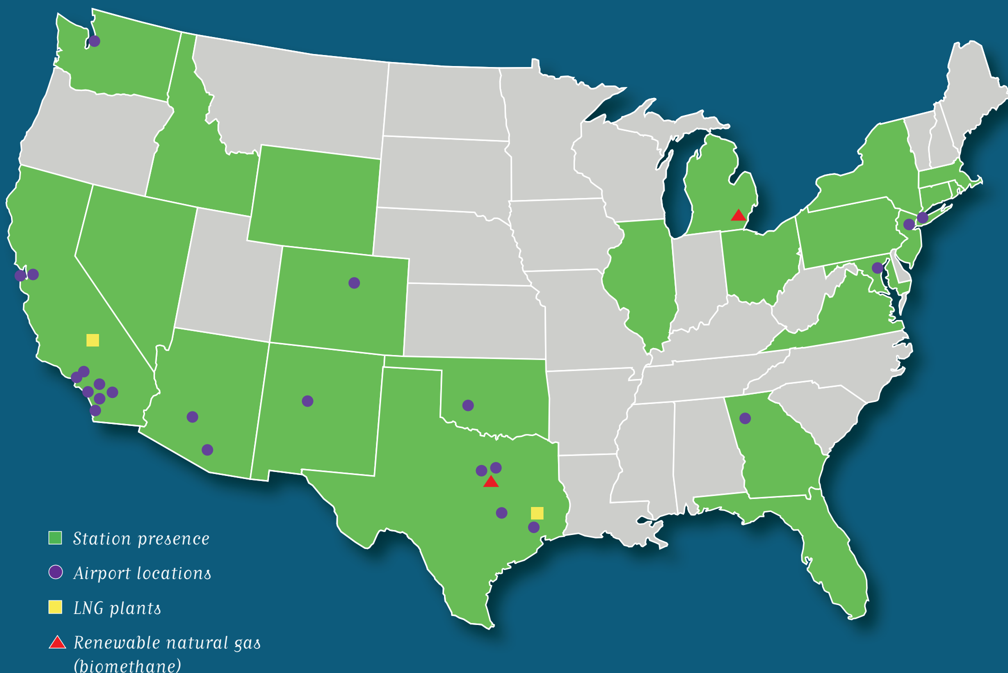
Web Site

www.cleanenergyfuels.com

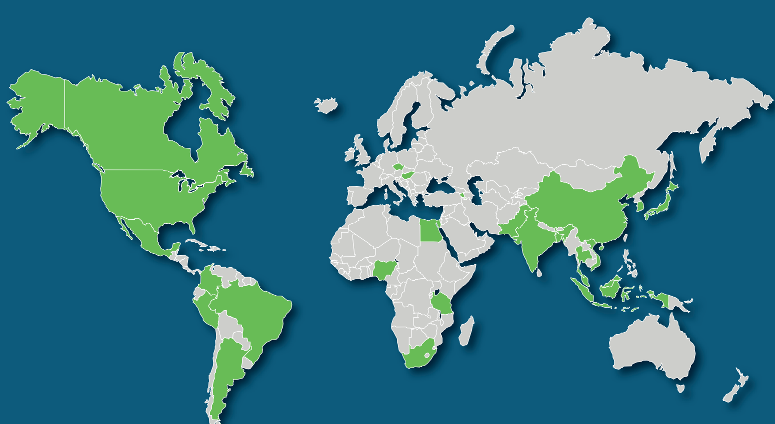
NORTH AMERICA'S LEADER IN CLEAN TRANSPORTATION

Clean Energy is the leading provider of natural gas (CNG and LNG) for transportation in North America. It fuels more than 21,200 vehicles daily at over 224 strategic locations across the United States and Canada, including 23 of the nation's largest airport complexes. Clean Energy also owns and operates two LNG production plants, one in Willis, Texas and one in Boron, California.

In addition to its headquarters in Seal Beach, California, Clean Energy maintains offices in Arizona, Colorado, New Hampshire, Texas, Vancouver, BC and Washington, DC.



On the global front, Clean Energy has manufacturing offices in Canada and China, major service centers in Bangladesh, Canada, China and Colombia, and installations in 24 countries.



Clean Energy®

CLEAN ENERGY
3020 Old Ranch Parkway, Suite 400
Seal Beach, California 90740
562.493.2804
www.cleanenergyfuels.com

CLEAN ENERGY FUELS CORP.

FORM 10-Q
(Quarterly Report)

Filed 11/08/11 for the Period Ending 09/30/11

Address	3020 OLD RANCH PARKWAY, SUITE 400 SEAL BEACH, CA 90740
Telephone	(562) 493-2804
CIK	0001368265
Symbol	CLNE
SIC Code	4932 - Gas and Other Services Combined
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	12/31

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2011

Commission File Number: 001-33480

CLEAN ENERGY FUELS CORP.

(Exact name of registrant as specified in its charter)

Delaware	**33-0968580**
(State or other jurisdiction of incorporation)	(IRS Employer Identification No.)

3020 Old Ranch Parkway, Suite 400, Seal Beach CA 90740
(Address of principal executive offices, including zip code)

(562) 493-2804
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232,405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act). Yes ☐ No ☒

As of November 1, 2011, there were 70,395,657 shares of the registrant's common stock, par value $0.0001 per share, issued and outstanding.

CLEAN ENERGY FUELS CORP. AND SUBSIDIARIES

INDEX

Table of Contents

PART I.—FINANCIAL INFORMATION

Item 1.—Financial Statements (Unaudited)

Clean Energy Fuels Corp. and Subsidiaries

Condensed Consolidated Balance Sheets

December 31, 2010 and September 30, 2011 (Unaudited)

(In thousands, except share data)

	December 31, 2010	September 30, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 55,194	$ 159,003
Restricted cash	2,500	5,684
Accounts receivable, net of allowance for doubtful accounts of $702 and $673 as of December 31, 2010 and September 30, 2011, respectively	45,645	39,710
Other receivables	27,280	18,989
Inventory, net	20,483	32,374
Prepaid expenses and other current assets	10,959	12,345
Total current assets	162,061	268,105
Land, property and equipment, net	211,643	246,534
Restricted cash	—	67,756
Notes receivable and other long-term assets	15,059	16,072
Investments in other entities	10,748	16,296
Goodwill	71,814	72,069
Intangible assets, net	112,174	104,771
Total assets	$ 583,499	$ 791,603
Liabilities and Stockholders' Equity		
Current liabilities:		
Current portion of long-term debt and capital lease obligations	$ 22,712	$ 22,452
Accounts payable	28,635	22,945
Accrued liabilities	28,137	29,226
Deferred revenue	17,507	18,559
Total current liabilities	96,991	93,182
Long-term debt and capital lease obligations, less current portion	41,704	265,718
Other long-term liabilities	28,588	20,127
Total liabilities	167,283	379,027
Commitments and contingencies (Note 16)		
Stockholders' equity:		
Preferred stock, $0.0001 par value. Authorized 1,000,000 shares; issued and outstanding no shares	—	—
Common stock, $0.0001 par value. Authorized 149,000,000 shares; issued and outstanding 69,610,098 shares and 70,382,655 shares at December 31, 2010 and September 30, 2011, respectively	7	7
Additional paid-in capital	569,202	587,992
Accumulated deficit	(151,926)	(178,651)
Accumulated other comprehensive loss	(3,996)	(202)
Total Clean Energy Fuels Corp. stockholders' equity	413,287	409,146
Noncontrolling interest in subsidiary	2,929	3,430
Total stockholders' equity	416,216	412,576
Total liabilities and stockholders' equity	$ 583,499	$ 791,603

See accompanying notes to condensed consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries

Condensed Consolidated Statements of Operations

For the Three Months and Nine Months Ended September 30, 2010 and 2011

(Unaudited)

(In thousands, except share and per share data)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2011
Revenue:				
Product revenues	$ 40,975	$ 64,237	$ 114,682	$ 184,292
Service revenues	4,679	7,845	13,996	22,244
Total revenues	45,654	72,082	128,678	206,536
Operating expenses:				
Cost of sales:				
Product cost of sales	31,190	48,853	85,378	139,591
Service cost of sales	2,319	3,901	6,305	10,591
Derivative (gains):				
Series I warrant valuation	(7,866)	(1,524)	(5,876)	(3,059)
Selling, general and administrative	15,855	20,140	44,382	59,823
Depreciation and amortization	5,507	7,554	15,568	22,396
Total operating expenses	47,005	78,924	145,757	229,342
Operating loss	(1,351)	(6,842)	(17,079)	(22,806)
Interest income (expense), net	(70)	(3,194)	17	(5,520)
Other expense	(309)	(2,450)	(305)	(1,662)
Income from equity method investments	96	99	202	474
Loss before income taxes	(1,634)	(12,387)	(17,165)	(29,514)
Income tax (expense) benefit	(290)	960	836	2,872
Net loss	(1,924)	(11,427)	(16,329)	(26,642)
Loss (income) of noncontrolling interest	94	73	27	(84)
Net loss attributable to Clean Energy Fuels Corp.	$ (1,830)	$ (11,354)	$ (16,302)	$ (26,726)
Loss per share attributable to Clean Energy Fuels Corp.				
Basic	$ (0.03)	$ (0.16)	$ (0.27)	$ (0.38)
Diluted	$ (0.03)	$ (0.16)	$ (0.27)	$ (0.38)
Weighted average common shares outstanding				
Basic	63,992,763	70,364,202	60,970,130	70,255,311
Diluted	63,992,763	70,364,202	60,970,130	70,255,311

See accompanying notes to condensed consolidated financial statements.

Clean Energy Fuels Corp.

Condensed Consolidated Statements of Cash Flows

For the Nine Months Ended September 30, 2010 and 2011

(Unaudited)

(In thousands)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2011
Cash flows from operating activities:		
Net loss	$ (16,329)	$ (26,642)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	15,568	22,396
Provision for doubtful accounts, notes receivables and inventory	139	335
Derivative loss (gain)	(5,876)	(3,059)
Stock-based compensation expense	9,222	10,093
Accretion of notes payable	—	2,060
Amortization of debt issuance cost	—	238
Loss (gain) on contingent consideration for acquisitions	—	(2,554)
Changes in operating assets and liabilities, net of assets and liabilities acquired:		
Accounts and other receivables	(6,073)	14,153
Inventory	(3,434)	(11,943)
Margin deposits on futures contracts	(2,987)	2,981
Prepaid expenses and other assets	416	(3,834)
Accounts payable	13,588	(5,690)
Accrued expenses and other	7,562	3,444
Net cash provided by operating activities	11,796	1,978
Cash flows from investing activities:		
Purchases of property and equipment	(41,437)	(49,546)
Proceeds from sale of property and equipment	280	—
Proceeds from sale of loans receivable	324	—
Acquisition, net of cash acquired	(15,585)	—
Restricted cash	—	(70,941)
Investments in other entities	(635)	(4,712)
Net cash used in investing activities	(57,053)	(125,199)
Cash flows from financing activities:		
Proceeds from issuance of common stock and exercise of stock options	10,784	1,197
Proceeds from capital lease obligations and debt instruments	—	242,730
Contingent consideration paid relating to business acquisitions	—	(2,396)
Proceeds from revolving line of credit	—	34,383
Proceeds from minority interest DCE equity contribution	—	417
Payments for debt issuance costs	—	(3,053)
Repayment of borrowing under revolving line of credit	—	(29,882)
Repayment of capital lease obligations and debt instruments	(435)	(15,854)
Net cash provided by financing activities	10,349	227,542
Effect of exchange rates on cash and cash equivalents	—	(512)
Net increase (decrease) in cash	(34,908)	103,809
Cash, beginning of period	67,087	55,194
Cash, end of period	$ 32,179	$ 159,003
Supplemental disclosure of cash flow information:		
Income taxes paid	$ 219	$ 873
Interest paid, net of approximately $295 and $319 capitalized, respectively	804	2,551

See accompanying notes to condensed consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries

Notes to Condensed Consolidated Financial Statements

(Unaudited)

(In thousands, except share data)

Note 1—General

Nature of Business: Clean Energy Fuels Corp., together with its majority and wholly owned subsidiaries (hereinafter collectively referred to as the "Company"), is engaged in the business of selling natural gas fueling solutions to its customers, primarily in the United States. Beginning September 7, 2010 with its acquisition of I.M.W. Industries, Ltd. ("IMW"), the Company began selling certain equipment and services internationally. The Company has a broad customer base in a variety of markets, including public transit, refuse, airports and trucking. The Company operates, maintains or supplies approximately 257 natural gas fueling locations in Arizona, California, Colorado, Connecticut, Florida, Georgia, Idaho, Illinois, Indiana, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Rhode Island, Texas, Virginia, Washington and Wyoming within the United States, and in British Columbia and Ontario within Canada. The Company also generates revenue through operation and maintenance ("O&M") agreements with certain customers, through building and selling or leasing natural gas fueling stations to its customers, and through financing its customers' vehicle purchases. In April 2008, the Company opened its first compressed natural gas ("CNG") station in Lima, Peru through the Company's joint venture, Clean Energy del Peru. In August 2008, the Company acquired 70% of the outstanding membership interests of Dallas Clean Energy, LLC ("DCE"). DCE, through a 70% owned subsidiary, owns a facility that collects, processes and sells renewable biomethane collected from a landfill in Dallas, Texas. On October 1, 2009, the Company acquired 100% of BAF Technologies, Inc. ("BAF"), a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles. On September 7, 2010, the Company acquired 100% of IMW, a company engaged in the manufacturing and servicing of natural gas fueling compressors and related equipment. On December 15, 2010, the Company acquired 100% of Wyoming Northstar Incorporated, Southstar, LLC, and M&S Rental LLC (collectively "Northstar"), a provider of design, engineering, construction and maintenance services for liquefied natural gas ("LNG") and liquefied to compressed ("LCNG") fueling stations.

Basis of Presentation: The accompanying interim unaudited condensed consolidated financial statements include the accounts of the Company and its subsidiaries, and, in the opinion of management, reflect all adjustments, which include only normal recurring adjustments, necessary to state fairly the Company's financial position, results of operations and cash flows for the three and nine months ended September 30, 2010 and 2011. All intercompany accounts and transactions have been eliminated in consolidation. The three and nine month periods ended September 30, 2010 and 2011 are not necessarily indicative of the results to be expected for the year ending December 31, 2011 or for any other interim period or for any future year.

Certain information and disclosures normally included in the notes to the financial statements have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC"), but the resultant disclosures contained herein are in accordance with accounting principles generally accepted in the United States of America ("US GAAP") as they apply to interim reporting. The condensed consolidated financial statements should be read in conjunction with the consolidated financial statements as of and for the year ended December 31, 2010 that are included in the Company's Annual Report on Form 10-K filed with the SEC on March 10, 2011.

Use of Estimates: The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenues and expenses recorded during the reporting period. Actual results could differ from those estimates. Current economic conditions may require the use of additional estimates and these estimates may be subject to a greater degree of uncertainty as a result of the uncertain economy.

Note 2—Acquisitions

Natural Gas Fueling Compressors

On September 7, 2010, the Company, acting through certain of its subsidiaries, completed its purchase of the advanced natural gas fueling compressor and related equipment manufacturing and servicing business of IMW. IMW manufactures and services advanced, non-lubricated natural gas fueling compressors and related equipment for the global natural gas fueling market. IMW is headquartered near Vancouver, British Columbia, and has other manufacturing facilities near Shanghai, China and in Ferndale, Washington, and has sales and service offices in Bangladesh, Colombia, Peru and the United States.

In connection with the closing of the Company's acquisition of IMW, a subsidiary of the Company (the "Acquisition Subsidiary") paid an upfront cash payment of $15,034 and issued 4,017,408 shares of the Company's common stock at closing to IMW's shareholder. The issued shares were registered and available for immediate resale by the IMW shareholder. An additional $288 was paid by the Acquisition Subsidiary when the Chinese regulatory authorities subsequently approved the transfer of IMW Compressors (Shanghai) Co. Ltd. to the Acquisition Subsidiary. The Acquisition Subsidiary also issued the following promissory notes to the IMW shareholder (collectively, the "IMW Notes"): (i) a promissory note with a principal amount of $12,500 that was paid on January 31, 2011, (ii) a promissory note with a principal amount of $12,500 that is due and payable on January 31, 2012, (iii) a promissory note with a principal amount of $12,500 that is due and payable on January 31, 2013, and (iv) a promissory note with a principal amount of $12,500 that is due and payable on January 31, 2014. Each payment under the IMW Notes will consist of $5,000 in cash and $7,500 in cash and/or shares of the Company's common stock (the exact combination of cash and/or stock to be determined at the Company's option). In addition, pursuant to a security agreement executed at closing, the IMW Notes are secured by a subordinate security interest in IMW. On January 31, 2011, the Company paid $5,000 in cash and issued 601,926 shares to the IMW shareholder to settle the IMW Note due on that date.

IMW's former shareholder may also receive additional contingent consideration based on future gross profits earned by IMW over the next four years. The additional contingent consideration is subject to achieving minimum gross profit targets and will be determined based on a sliding scale that increases at certain gross profit levels. During the four-year period during which these earn-out payments may be made, the former shareholder of IMW will receive between zero and 23% of the gross profit of IMW as additional consideration, up to a maximum of $40,000 in the aggregate (which maximum would be payable if IMW achieves approximately $174,000 in gross profit over the four-year period during which these earn-out payments may be made).

The Company accounted for this acquisition in accordance with FASB authoritative guidance for business combinations, which requires the Company to recognize the assets acquired and the liabilities assumed, measured at their fair values, as of the date of acquisition. The following table summarizes the allocation of the aggregate purchase price to the fair value of the assets acquired and liabilities assumed:

Current assets	$	27,149
Property, plant and equipment		2,559
Identifiable intangible assets		81,400
Goodwill		45,304
Total assets acquired		156,412
Liabilities assumed		(26,241)
Total purchase price	$	130,171

Management allocated approximately $81,400 of the purchase price to certain identifiable intangible assets related to technology, customer relationships, non-compete agreements, and trademarks that were acquired with the acquisition. The fair value of the identifiable intangible assets will be amortized on a straight-line basis over their estimated useful lives ranging from three to twenty years. In addition, management allocated $45,304 to goodwill as part of the acquisition and recorded a contingent liability of $9,300 related to the additional contingent consideration described above. Under FASB authoritative guidance, the Company is required to adjust the value of the contingent consideration for this acquisition in the statement of operations as the value of the obligation changes each reporting period. The Company recorded a gain of $1,563 and $2,163, respectively, during the three and nine month periods ended September 30, 2011 related to this contingency. This amount is recorded in selling, general and administrative expenses in the accompanying condensed consolidated statement of operations. At September 30, 2011, the fair value of the contingent consideration was $5,700.

The results of operations of IMW have been included in the Company's consolidated financial statements since September 7, 2010.

Liquefied Natural Gas Station Construction

On December 15, 2010, the Company acquired Northstar, a leading provider of design, engineering, construction and maintenance services for LNG and LCNG fueling stations. The purchase price primarily consisted of a closing cash payment in the amount of $7,414. The remaining consideration consists of five annual payments in the amount of $700 each commencing on the first anniversary of the closing date, and up to $4,000 in retention bonuses to certain key employees to be paid in four annual installments commencing on the first anniversary of the closing date.

The Company accounted for this acquisition in accordance with FASB authoritative guidance for business combinations, which requires the Company to recognize the assets acquired and the liabilities assumed, measured at their fair values, as of the date of acquisition. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed:

Current assets	$	4,434
Property, plant and equipment		941
Identifiable intangible assets		3,350
Goodwill		5,228
Total assets acquired		13,953
Liabilities assumed		(3,648)
Total purchase price	$	10,305

Management allocated $3,350 of the purchase price to certain identifiable intangible assets, $2,250 of which is related to non-compete agreements, customer relationships, and backlog. The fair value of these identifiable intangibles is being amortized on a straight-line basis over their estimated useful lives ranging from one to ten years. The Company also allocated $1,100 of the purchase price to trademarks, which management believes has an indefinite useful life. In addition, management allocated $5,228 to goodwill as part of the acquisition.

As of November 8, 2011, the purchase price allocation is preliminary and could change materially in subsequent periods. Any subsequent changes to the purchase price allocation that result in material changes to the Company's consolidated financial results will be adjusted retroactively. The final purchase price allocation is pending the consideration of certain income tax related matters.

The results of Northstar's operations have been included in the Company's consolidated financial statements since December 15, 2010.

Note 3—Cash and Cash Equivalents

The Company considers all highly liquid investments with maturities of three months or less on the date of acquisition to be cash equivalents.

Note 4—Restricted Cash

As of December 31, 2010, the Company's restricted cash balance consisted of cash held in a payment reserve account in connection with the Company's PCB Credit Agreement that was retired on August 14, 2011. See note 12 for a discussion of restricted cash at September 30, 2011.

Note 5—Derivative Transactions

The Company marks to market its open futures positions at the end of each period and records the net unrealized gain or loss during the period in derivative (gains) losses in the condensed consolidated statements of operations or in accumulated other comprehensive income in the condensed consolidated balance sheets in accordance with FASB authoritative guidance. The Company recorded unrealized (gains) losses of $5,129 and $(1,689) in other comprehensive income (loss) for the nine month periods ended September 30, 2010 and 2011, respectively, related to its futures contracts. Of the $2,661 liability for the Company's future contracts at September 30, 2011, $2,546 is included in accrued liabilities for the short-term amount, and $115 is included in other long-term liabilities for the long-term amount in the Company's condensed consolidated balance sheet as of September 30, 2011. Of the $4,970 liability for the Company's futures contracts at September 30, 2010, $3,263 is included in accrued liabilities for the short-term amount, and $1,707 is included in other long-term liabilities for the long-term amount in the Company's condensed consolidated balance sheet as of September 30, 2010. The Company's ineffectiveness related to its futures contracts during the three and nine month periods ended September 30, 2010 and 2011 was insignificant. For the three months ended September 30, 2010 and 2011, the Company recognized a loss of approximately $769 and $864, respectively, in cost of sales in the accompanying condensed consolidated statements of operations related to its futures contracts that were settled during the respective periods. For the nine months ended September 30, 2010 and 2011, the Company recognized a loss of $906 and $2,295, respectively, in cost of sales in the accompanying condensed consolidated statements of operations related to its futures contracts that were settled during the respective periods.

The following table presents the notional amounts and weighted-average fixed prices per gasoline gallon equivalent of the Company's natural gas futures contracts as of September 30, 2011:

	Gallons	Weighted Average Price Per Gasoline Gallon Equivalent
October to December, 2011	2,880,000	$ 0.82
2012	5,160,000	$ 0.81
January to May, 2013	300,000	$ 0.81

Note 6—Other Receivables

Other receivables at December 31, 2010 and September 30, 2011 consisted of the following:

	December 31, 2010	September 30, 2011
Fuel tax credits	17,577	7,452
Other	9,703	11,537
	$ 27,280	$ 18,989

Note 7—Inventories

Inventories are stated at the lower of cost or market on a first-in, first-out basis. Management's estimate of market includes a provision for slow-moving or obsolete inventory based upon inventory on hand and forecasted demand.

Inventories consisted of the following as of December 31, 2010 and September 30, 2011:

	December 31, 2010	September 30, 2011
Raw materials and spare parts	$ 17,634	$ 26,704
Work in process	1,196	3,452
Finished goods	1,653	2,218
Total	$ 20,483	$ 32,374

Note 8—Land, Property and Equipment

Land, property and equipment at December 31, 2010 and September 30, 2011 are summarized as follows:

	December 31, 2010	September 30, 2011
Land	$ 1,198	$ 1,198
LNG liquefaction plants	92,856	92,927
Biomethane plants	2,867	14,603
Station equipment	91,492	108,155
LNG trailers	12,020	13,510
Other equipment	21,611	23,319
Construction in progress	53,386	69,918
	275,430	323,630
Less: accumulated depreciation	(63,787)	(77,096)
	$ 211,643	$ 246,534

Note 9—Investments in Other Entities

Through September 30, 2011, the Company has invested approximately $13,106 in The Vehicle Production Group LLC ("VPG"), a company that is developing a natural gas vehicle made in the United States for taxi and paratransit use. The Company accounts for its investment in VPG under the cost method of accounting as the Company does not have the ability to exercise significant influence over VPG's operations.

On February 25, 2011 (the "Closing Date"), the Company paid $1,200 for a 19.9% interest in ServoTech Engineering, Inc. ("ServoTech"), a company that provides design and engineering services for natural gas fueling systems among other services. The Company also has an option to purchase the remaining 81.1% of ServoTech for $2,800 over the 15 month period following the Closing Date. The Company accounts for its interest using the equity method of accounting as the Company has the ability to exercise significant influence over ServoTech's operations.

Note 10— Accrued Liabilities

Accrued liabilities at December 31, 2010 and September 30, 2011 consisted of the following:

	December 31, 2010	September 30, 2011
Salaries and wages	$ 2,218	$ 5,561
Accrued gas and equipment purchases	6,995	4,358
Other	18,924	19,307
	$ 28,137	$ 29,226

Note 11—Warranty Liability

The Company records warranty liabilities at the time of sale for the estimated costs that may be incurred under its standard warranties. Changes in the warranty liability are presented in the following tables:

	September 30, 2010	September 30, 2011
Warranty liability at beginning of year	$ 1,136	$ 2,338
Assumed liability through acquisitions	742	—
Costs accrued for new warranty contracts and changes in estimates for pre-existing warranties	478	1,977
Service obligations honored	(363)	(1,544)
Warranty liability at end of period	$ 1,993	$ 2,771

Note 12—Long-term Debt

Credit Agreement

In conjunction with the Company's acquisition of its 70% interest in Dallas Clean Energy, LLC ("DCE"), on August 15, 2008, the Company entered into a credit agreement ("Credit Agreement") with PlainsCapital Bank ("PCB"). The Company borrowed $18,000 (the "Facility A Loan") to finance the acquisition of its membership interests in DCE. The Company also obtained a $12,000 line of credit from PCB to finance capital improvements of the DCE processing facility and to pay certain costs and expenses related to the acquisition and the PCB loans (the "Facility B Loan").

On October 7, 2009, the Facility A Loan was repaid in full and converted into a $20,000 line of credit (the "A Line of Credit") pursuant to an amendment to the Credit Agreement. On August 13, 2010, the Credit Agreement was amended to extend the maturity date of the A Line of Credit to August 14, 2011 and add an unused facility fee. The amendment also provides for a 1-year option to extend the maturity date to August 14, 2012, subject to the Company not being in default on the A Line of Credit. The unused facility fees are to be paid quarterly, in an amount equal to one-tenth of one percent (0.10%) of the unused portion. The Company elected not to renew the A Line of Credit on August 14, 2011 and the Line of Credit expired on that date.

The principal amount of the Facility B Loan became due and payable in annual payments commencing on August 1, 2009, and continuing each anniversary date thereafter, with each such payment being in an amount equal to the lesser of twenty percent of the aggregate principal amount of the Facility B Loan then outstanding or $2,800. Pursuant to an amendment to the Facility B loan between the Company and PCB dated November 1, 2010, PCB agreed to forgo the scheduled payment due from the Company on August 1, 2010 in the amount of $2,059 until January 31, 2011, which payment was made on such date. On March 31, 2011, the Company paid in full the remaining principal and interest that was due under the Facility B Loan.

The Company also entered into a Loan Agreement with DCE (the "DCE Loan") to provide secured financing of up to $14,000 to DCE for future capital expenditures or other uses as agreed to by the Company, in its sole discretion. On March 31, 2011, the entire amount of unpaid principal and interest due under the DCE Loan was paid to the Company. The interest income related to the DCE Loan was eliminated in the accompanying condensed consolidated statements of operations.

Revenue Bonds

On March 25, 2011, the Company's 70% owned subsidiary, Dallas Clean Energy McCommas Bluff, LLC, a Delaware limited liability company ("DCEMB"), arranged for a $40,200 tax-exempt bond issuance (the "Revenue Bonds"). The Revenue Bonds will be repaid from the revenue generated by DCEMB from the sale of renewable natural gas (or biomethane). The Revenue Bonds are secured by the revenue and assets of DCEMB and are non-recourse to DCEMB's direct and indirect parent companies, including the Company. The bond repayments are amortized through December 2024 and the average coupon interest rate on the bonds is 6.60%. The bond issuance closed March 31, 2011.

The bond proceeds will primarily be used to finance further improvements and expansion of the landfill gas processing facility owned by DCEMB at the McCommas Bluff landfill outside of Dallas, Texas. A portion of the proceeds were used to retire the DCE Loan discussed above. The Company, in turn, used the proceeds from the payoff of the DCE Loan to repay approximately $8,000 owed by the Company to PCB under the Facility B Loan on March 31, 2011.

Pursuant to the Loan Agreement, dated as of January 1, 2011 (the "Loan Agreement"), between DCEMB and the Mission Economic Development Corporation (the "Issuer"), DCEMB has covenanted with the Issuer to make loan repayments equal to the principal and interest coming due on the Revenue Bonds. DCEMB executed a promissory note, dated March 31, 2011 (the "Note"), as evidence of its obligations under the Loan Agreement. Pursuant to the Trust Indenture, dated as of January 1, 2011 (the "Indenture"), the Issuer has pledged and assigned to the Trustee all of the Issuer's right, title and interest in and to the Loan Agreement (with certain specified exceptions) and the Note.

The obligations of DCEMB under the Loan Agreement are secured by a Leasehold Deed of Trust, Assignment of Rents, Security Agreement and Fixture Filing, dated as of January 1, 2011 (the "Deed of Trust"), executed by DCEMB in favor of the deed of trust trustee named therein for the benefit of the Bank of New York Mellon Trust Company, N.A., as Trustee (the "Trustee"). In addition, DCEMB executed a Security Agreement (the "Security Agreement"), as security for its obligations, pursuant to which DCEMB granted to the Trustee a security interest in all right, title and interest of DCEMB to the Collateral (as defined in the Security Agreement), which includes, but is not limited to, DCEMB's rights, title and interest in any gas sale agreements, including the gas sale agreement with Shell Energy North America (US), L.P. (the "Shell Gas Sale Agreement"), and the funds and accounts held under the Indenture.

Pursuant to a Consent and Agreement, by and between Shell Energy, The Bank of New York Mellon Trust Company, N.A., as Depository Bank (the "Depository Bank"), DCEMB and the Trustee, dated as of January 1, 2011 (the "Consent Agreement"), Shell Energy agreed to make all payments due to DCEMB under the Shell Gas Sale Agreement to the Depository Bank. In addition, other revenues generated through the sale of gas produced at the facility will be paid directly to the Depository Bank pursuant to a Depository and Control Agreement, dated as of January 1, 2011 (the "Depository Agreement"), among DCEMB, the Trustee and the Depository Bank.

All payments received by the Depository Bank will be placed into various accounts in accordance with the requirements of the Indenture and the Depository Agreement. The funds in these accounts will be used to service required debt payments, finance further improvements and expansion of the landfill gas processing facility owned by DCEMB, finance the operations and maintenance of DCEMB, finance certain expenses associated with setting up and maintaining the accounts, and other uses as prescribed in the Depository Agreement. The Depository Bank will make payments out of these accounts in accordance with the requirements of the Depository Agreement. At the end of each month after all required account fundings have been fulfilled in accordance with the Depository Agreement, all remaining excess funds will be placed into a Surplus Account. The funds in the Surplus Account will be delivered to DCEMB so long as (i) DCEMB's Debt Service Coverage Ratio (as defined) for the most recent four calendar quarters then ended equals or exceeds 1.25:1, (ii) DCEMB's Debt Service Coverage Ratio (as defined) is reasonably projected to equal or exceed 1.25:1 for the next four calendar quarters, (iii) no events of default have occurred as defined by the Indenture and the Loan Agreement, and (iv) after giving effect to the transfer, DCEMB's Minimum Days Cash on Hand (as defined) shall be, or shall at any time be projected to be, more than the lesser of thirty-five Days Cash on Hand (as defined) or $1,300. Due to these restrictions on this cash, the Company has classified all of this cash as restricted cash on the balance sheet. The Company records the restricted cash that is expected to be received and used within the next 12 months from the Depository Bank for working capital and operating purposes as current in its balance sheet, and presents the remaining balance as non-current in the line item notes receivable and other long term assets. At September 30, 2011, $20,756 was included in long term restricted cash and $4,516 was included in short term restricted cash in the accompanying condensed consolidated balance sheet.

The Indenture and the Loan Agreement have certain non-financial debt covenants with which DCEMB must comply. As of September 30, 2011, DCEMB was in compliance with all its debt covenants.

Pursuant to a collateral assignment and Consent and Agreement with Atmos Pipeline - Texas ("Atmos"), DCEMB has collaterally assigned to the Trustee, subject to certain reserved rights and the consent of Atmos, the transportation agreements of the Company with Atmos.

Purchase Notes

In connection with the closing of the Company's acquisition of IMW, the Company agreed to make future payments consisting of four annual payments in the amount of $12,500. Each payment under the IMW Notes will consist of $5,000 in cash and $7,500 in cash and/or shares of the Company's common stock (the exact combination of cash and/or stock to be determined at the Company's option). In addition, pursuant to a security agreement executed at closing, the IMW Notes are secured by a subordinate security interest in IMW. On January 31, 2011, the Company paid $5,000 in cash and issued 601,926 shares to the IMW shareholder to settle the IMW Note due on that date.

In connection with the closing of the Company's acquisition of Northstar, the Company agreed to make future payments consisting of five annual payments in the amount of $700 each with the first payment due December 15, 2011.

The difference between the carrying amount and the face amount of these obligations will be accreted to interest expense over the remaining term of the obligations.

HSBC Lines of Credit

Also in connection with the closing of the Company's acquisition of IMW, the Company entered into an Assumption Agreement (the "Assumption Agreement") with HSBC Bank Canada ("HSBC"), which was amended on March 29, 2011 and September 26, 2011, pursuant to which the Company assumed the obligations and liabilities of IMW under the following arrangements, as amended, with HSBC (collectively, the "IMW Lines of Credit"):

(i) An operating line of credit with a limit of $10,000 in Canadian dollars ("CAD") bearing interest at prime plus 1.00%, to assist in financing the day-to-day working capital needs of IMW.

(ii) A bank guarantee line with a limit of CAD$3,000, which allows IMW to provide guarantees and/or standby letters of credit to overseas suppliers or bid/performance deposits on contracts.

(iii) A forward exchange contract line with a limit of CAD$13,750. The forward exchange contract line allows IMW to enter into foreign exchange forward contracts up to the notional limit of CAD$13,750 (no forward exchange contracts were outstanding at September 30, 2011).

(iv) A MasterCard limit with a maximum amount of CAD$150.

(v) An operating line with a limit of 5,000 Renminbi ("RMB") (CAD$808) bearing interest at the 6 month People's Bank of China rate plus 2.5% and a sub-limit bank guarantee line of 5,000 RMB. The aggregate of the balances in the lines cannot exceed 5,000 RMB.

(vi) A 16,750 Bengali Taka (CAD$234) operating line of credit bearing interest at 14%.

(vii) A 170,000 Columbian Peso (CAD$92) operating line of credit bearing interest at the Colombia benchmark rate plus 7 to 9%.

The IMW Lines of Credit are secured by a general security agreement providing a first priority security interest in all present and after acquired personal property of IMW, including specific charges on all serial numbered goods, inventory and other assets and assignment of risk insurance (the "Security"). The IMW Lines of Credit contain no fixed repayment terms or mandatory principal payments and are due on demand. Based on the relevant accounting guidance, the Company has classified this debt pursuant to the credit agreement as short-term given that it is due on demand.

The Assumption Agreement with HSBC also includes certain financial covenants. Among these financial covenants are that IMW shall not permit: 1) its ratio of debt to tangible net worth to be greater than 4.0 to 1.0 until December 31, 2011, and greater than 3.75 to 1.0 from January 1, 2012 through March 31, 2012, and greater than 3.5 to 1.0 from April 1, 2012 through June 30, 2012, and greater than 3.0 to 1.0 on or after July 1, 2012, 2) its tangible net worth to at anytime be below CAD$7,000 and 3) its ratio of current assets to current liabilities to be less than 1.15 to 1.0 until March 31, 2012 and less than 1.25 to 1.0 on or after April 1, 2012. IMW was in compliance with the financial covenants as of September 30, 2011.

In addition, the Company and IMW agreed that should the making of any scheduled payment by IMW to the seller of IMW under the IMW Notes result in IMW being in breach of the Assumption Agreement, the IMW Lines of Credit or the Security, the Company shall furnish IMW with the funds needed to remain in compliance with the Assumption Agreement, the IMW Lines of Credit and the Security. Further, the Company and IMW agreed that should IMW make any future earn-out payments to the seller of IMW in connection with the acquisition of IMW, and should the making of such earn-out payments result in IMW being in breach of the Assumption Agreement, the IMW Lines of Credit or the Security, then the Company shall furnish IMW with the funds needed to make such earn-out payments and remain in compliance with the Assumption Agreement, the IMW Lines of Credit and the Security.

Chesapeake Notes

On July 11, 2011, the Company entered into a Loan Agreement (the “CHK Agreement”) with Chesapeake NG Ventures Corporation (“Chesapeake”), an indirect wholly owned subsidiary of Chesapeake Energy Corporation, whereby Chesapeake agreed to purchase from the Company up to $150 million aggregate principal amount of debt securities for the development, construction and operation of liquefied natural gas stations (the “CHK Financing”) pursuant to the issuance of three convertible promissory notes, each having a principal amount of $50 million (each a “CHK Note” and collectively the “CHK Notes”). Chesapeake Energy Corporation guaranteed Chesapeake’s commitment to purchase the CHK Notes under the CHK Agreement.

The first CHK Note was issued on July 11, 2011, and the Company expects to issue the second and third CHK Notes on June 29, 2012 and June 28, 2013, respectively. The CHK Notes bear interest at the rate of 7.5% per annum (payable quarterly, in arrears, on March 31, June 30, September 30 and December 31 of each year) and are convertible at Chesapeake’s option into shares of the Company’s common stock at a conversion price of $15.80 per share (the “CHK Conversion Price”). Subject to certain restrictions, the Company can force conversion of each CHK Note into shares of the Company’s common stock if, following the second anniversary of the issuance of a CHK Note, the Company’s shares of common stock trade at a 40% premium to the CHK Conversion Price for at least twenty trading days in any consecutive thirty trading day period. The entire principal balance of each CHK Note is due and payable seven years following its issuance, and the Company may repay each CHK Note in the shares of the Company’s common stock or cash. The CHK Agreement restricts the use of the CHK Financing proceeds to financing the development, construction and operation of liquefied natural gas stations and payment of certain related expenses. At September 30, 2011, $47 million of these funds were included in long term restricted cash as the Company anticipates primarily using the funds to build LNG fueling stations. The CHK Agreement also provides for customary events of default which, if any of them occurs, would permit or require the principal of and accrued interest on the CHK Notes to become or to be declared due and payable.

In connection with the CHK Financing, the Company also entered into a Registration Rights Agreement, dated July 11, 2011, with Chesapeake (the “CHK Registration Rights Agreement”) pursuant to which the Company agreed, subject to the terms and conditions of the CHK Registration Rights Agreement, to (i) file with the Securities and Exchange Commission one or more registration statements relating to the resale of the Company’s common stock issuable upon conversion of the CHK Notes and (ii) at the request of Chesapeake to participate in one or more underwritten offerings of the Company’s common stock issuable upon conversion of the CHK Notes. If the Company does not meet certain of its obligations under the CHK Registration Rights Agreement with respect to the registration of the Company’s common stock, it will be required to pay monthly liquidated damages of 0.75% of the principal amount of the CHK Note represented by the Company’s common stock included (or to be included, as the case may be) in the applicable registration statement until the related obligation is met. As of September 30, 2011, the Company met its obligations under the CHK Registration Rights Agreement.

SLG Notes

On August 24, 2011, the Company entered into Convertible Note Purchase Agreements (each, an “SLG Agreement” and collectively the “SLG Agreements”) with each of Springleaf Investments Pte. Ltd., a wholly-owned subsidiary of Temasek Holdings Pte. Ltd., Lionfish Investments Pte. Ltd., an investment vehicle managed by Seatown Holdings International Pte. Ltd., and Greenwich Asset Holding Ltd., a wholly-owned subsidiary of RRJ Capital Master Fund I, L.P. (each, a “Purchaser” and collectively, the “Purchasers”), whereby the Purchasers agreed to purchase from the Company an aggregate of $150 million in principal amount of 7.5% convertible notes due 2016 (each a “SLG Note” and collectively the “SLG Notes”). The transaction closed and the SLG Notes were issued on August 30, 2011.

The SLG Notes bear interest at the rate of 7.5% per annum (payable quarterly, in arrears, on March 31, June 30, September 30 and December 31 of each year) and are convertible at each Purchaser’s option into shares of the Company’s common stock at a conversion price of $15.00 per share (the “SLG Conversion Price”). Subject to certain restrictions, the Company can force conversion of each SLG Note into shares of the Company’s common stock if, following the second anniversary of the issuance of the SLG Note, the Company’s shares of common stock trade at a 40% premium to the SLG Conversion Price for at least 20 trading days in any consecutive 30 trading day period. The entire principal balance of each SLG Note is due and payable five years following its issuance, and the Company may repay the principal balance of each SLG Note in the shares of the Company’s common stock or cash. The SLG Agreements also provide for customary events of default which, if any of them occurs, would permit or require the principal of and accrued interest on the SLG Notes to become or to be declared due and payable.

In connection with the SLG Agreements, the Company also entered into a Registration Rights Agreement, dated August 30, 2011, with each of the Purchasers (the "SLG Registration Rights Agreements") pursuant to which the Company agreed, subject to the terms and conditions of the SLG Registration Rights Agreements, to (i) file with the Securities and Exchange Commission one or more registration statements relating to the resale of the Company's common stock issuable upon conversion of the SLG Notes and (ii) at the request of the Purchasers, participate in one or more underwritten offerings of the Company's common stock issuable upon conversion of the SLG Notes. If the Company does not meet certain of its obligations under the SLG Registration Rights Agreements with respect to the registration of the Company's common stock, it will be required to pay monthly liquidated damages of 0.75% of the principal amount of the SLG Note represented by the Company's common stock included (or to be included, as the case may be) in the applicable registration statement until the related obligation is met, not to exceed 4% of the aggregate principal amount of the SLG Notes per annum. As of September 30, 2011, the Company met its obligations under the SLG Registration Rights Agreement.

Long-term debt at December 31, 2010 and September 30, 2011 consisted of the following:

	December 31, 2010	September 30, 2011
Facility B loan	$ 9,909	$ —
IMW future payment notes	44,568	33,033
Northstar future payments	2,900	3,042
DCE notes	435	585
DCEMB Revenue Bonds (non recourse to the Company)	—	40,200
Chesapeake Notes	—	50,000
SLG Notes	—	150,000
IMW assumed debt	4,626	7,642
Capital lease obligations	1,978	3,668
Total debt and capital lease obligations	64,416	288,170
Less amounts due within one year and short-term borrowings	(22,712)	(22,452)
Total long-term debt and capital lease obligations	$ 41,704	$ 265,718

Note 13—Earnings Per Share

Basic earnings per share is based upon the weighted-average number of shares outstanding during each period. Diluted earnings per share reflects the impact of assumed exercise of dilutive stock options and warrants. The information required to compute basic and diluted earnings per share is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2011	2010	2011
Basic and diluted:				
Weighted average number of common shares outstanding	63,992,763	70,364,202	60,970,130	70,255,311

Certain securities were excluded from the diluted earnings per share calculations for the nine-months ended September 30, 2010 and 2011, respectively, as the inclusion of the securities would be anti-dilutive to the calculation. The amounts outstanding as of September 30, 2010 and 2011 for these instruments are as follows:

	September 30,	
	2010	2011
Options	9,563,055	10,753,026
Warrants	18,314,394	17,130,682
Convertible notes	—	13,164,557

Note 14—Comprehensive Loss

The following table presents the Company's comprehensive loss for the nine months ended September 30, 2010 and 2011:

	Nine Months Ended September 30,	
	2010	2011
Net loss attributable to Clean Energy Fuels Corp.	$ (16,302)	$ (26,726)
Derivative unrealized gains (losses)	(5,129)	1,689
Foreign currency translation adjustments	201	2,106
Comprehensive loss	$ (21,230)	$ (22,931)

Note 15—Stock-Based Compensation

The following table summarizes the compensation expense and related income tax benefit related to the stock-based compensation expense recognized during the periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2011	2010	2011
Stock options:				
Stock-based compensation expense	$ 3,260	$ 3,161	$ 9,222	$ 10,093
Income tax benefit	—	—	—	—
Stock-based compensation expense, net of tax	$ 3,260	$ 3,161	$ 9,222	$ 10,093

Stock Options

The following table summarizes the Company's stock option activity during the nine months ended September 30, 2011:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding, December 31, 2010	10,433,551	$ 10.09		
Options granted	840,500	13.93		
Options exercised	(170,631)	7.10		
Options forfeited	(350,394)	15.30		
Outstanding, September 30, 2011	10,753,026	$ 10.27	6.49	$ 9,178
Exercisable, September 30, 2011	7,087,508	$ 9.20	5.41	$ 13,594

As of September 30, 2011, there was $20,893 of total unrecognized compensation cost related to unvested shares. That cost is expected to be recognized over a weighted-average period of 1.41 years. The total fair value of shares vested during the nine months ended September 30, 2011 was $3,379.

All of the Company's unvested options issued prior to October 2005 vested in October 2005 when the Company experienced a change in control in accordance with the 2002 Plan. The Company plans to issue new shares to its employees upon the employees' exercise of their options. The intrinsic value of all options exercised during the nine months ended September 30, 2010 and 2011 was $10,813 and $1,337, respectively.

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2011:

	Nine Months Ended September 30, 2011
Dividend yield	0.00%
Expected volatility	69.94% to 74.38%
Risk-free interest rate	1.13% to 2.71%
Expected life in years	6.0

The weighted-average grant date fair values of options granted during the nine months ended September 30, 2010 and 2011 were $15.66, and $9.03, respectively. The volatility amounts used during the period were estimated based on a certain peer group of the Company's historical volatility for a period commensurate with the expected life of the options granted, the Company's historical volatility, and the Company's implied future volatility. The expected lives used during the periods were based on the weighted-average of the historical exercise behavior of prior options granted and the estimated future exercise date of the options outstanding. The risk free rates used during the year were based on the U.S. Treasury yield curve at the time of grant. The Company recorded $9,222 and $10,093 of stock option expense during the nine months ended September 30, 2010 and 2011, respectively. The Company has not recorded any tax benefit related to its stock option expense.

Note 16—Environmental Matters, Litigation, Claims, Commitments and Contingencies

The Company is subject to federal, state, local, and foreign environmental laws and regulations. The Company does not anticipate any expenditures to comply with such laws and regulations that would have a material impact on the Company's consolidated financial position, results of operations, or liquidity. The Company believes that its operations comply, in all material respects, with applicable federal, state, local and foreign environmental laws and regulations.

The Company may become party to various legal actions that arise in the ordinary course of its business. During the course of its operations, the Company is also subject to audit by tax authorities for varying periods in various federal, state, local, and foreign tax jurisdictions. Disputes may arise during the course of such audits as to facts and matters of law. It is impossible at this time to determine the ultimate liabilities that the Company may incur resulting from any lawsuits, claims and proceedings, audits, commitments, contingencies and related matters or the timing of these liabilities, if any. If these matters were to be ultimately resolved unfavorably, an outcome not currently anticipated, it is possible that such outcome could have a material adverse effect upon the Company's consolidated financial position or results of operations. However, the Company believes that the ultimate resolution of such actions will not have a material adverse affect on the Company's consolidated financial position, results of operations, or liquidity.

Note 17—Income Taxes

The Company is required to recognize the impact of a tax position in its financial statements if the position is more likely than not of being sustained by the taxing authority upon examination, based on the technical merits of the position. The Company accrues interest based on the difference between a tax position recognized in the financial statements and the amount claimed on its returns at statutory interest rates. The net interest incurred was immaterial for the three and nine month periods ended September 30, 2010 and 2011. Further, the Company accrues penalties if the tax position does not meet the minimum statutory threshold to avoid penalties. No penalties have been accrued by the Company. The Company's unrecognized tax benefits as of December 31, 2010 and September 30, 2011 were $24 and $279, respectively.

The Company is subject to taxation in the United States and various states and foreign jurisdictions. The Company's tax years for 2007 through 2010 are subject to examination by various tax authorities. The Company is no longer subject to U.S. examination for years before 2008 or state examinations for years before 2006. On July 15, 2010, the Internal Revenue Service ("IRS") sent the Company a letter disallowing approximately $5,073 related to certain claims the Company made from October 1, 2006 to June 30, 2008 under the Volumetric Excise Tax Credit program and seeking repayment of such amount. The Company believes its claims were properly made and is currently appealing the IRS's request for payment.

The Company's tax benefit for the period ended September 30, 2010 includes a refund of approximately $1,300 of alternative minimum taxes previously paid attributable to the Company's election of the extended net operating loss five-year carryback provision under the Worker, Homeownership, and Business Assistance Act of 2009.

Note 18— Fair Value Measurements

The Company follows the FASB authoritative guidance for fair value measurements with respect to assets and liabilities that are measured at fair value on a recurring basis and nonrecurring basis. Under the standard, fair value is defined as the exit price, or the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The standard also establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs market participants would use in valuing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions about the factors market participants would use in valuing the asset or liability developed based upon the best information available in the circumstances. The hierarchy is broken down into three levels. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities. Level 2 inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and inputs (other than quoted prices) that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability. Categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement.

During the nine months ended September 30, 2011, the Company's financial instruments consisted of natural gas futures contracts, debt instruments, contingent consideration related to its acquisitions, and its Series I warrants. The fair market value of the Company's debt instruments approximated their carrying values at September 30, 2010 and 2011. The Company uses quoted forward price curves, discounted to reflect the time value of money, to value its natural gas futures contracts. The Company uses projected financial results for the respective entities, discounted to reflect the time value of money, to value its contingent consideration obligations. The Company uses either a Monte Carlo simulation model or the Black-Scholes model, depending on the current terms, to value the Series I warrants. The Company considers a variety of market data with observable inputs when estimating the expected volatility used in the model. For example, the Company considers the historical volatilities of its competitors, the call option value of convertible bonds of certain peer group entities and the implied volatilities of its exchange traded stock options. The Company also uses the implied volatilities of its short-term (i.e. 3 to 9 month) traded options and extrapolates the data over the remaining term of the Series I warrants, which was approximately 4.58 years as of September 30, 2011. Given that the extrapolation beyond the term of the short term exchange traded options is not based on observable market inputs for a significant portion of the remaining term of the warrants, the Series I warrants have been classified as a Level 3 fair value determination in the table below.

The following tables provide information by level for assets and liabilities that are measured at fair value on a recurring basis:

Description	Balance at September 30, 2011	Quoted Prices In Active Markets for Identical Items (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities:				
Natural gas futures contracts	$ 2,661	$ —	$ 2,661	$ —
Contingent consideration obligations	6,250	—	—	6,250
Series I warrants	11,089	—	—	11,089

The following tables provide a reconciliation of the beginning and ending balances of items measured at fair value on a recurring basis in the table above that used significant unobservable inputs (Level 3).

Liabilities: Contingent Consideration	September 30, 2010	September 30, 2011
Beginning Balance	$ 3,100	$ 11,200
Business combinations	9,300	—
Total (gain) loss included in earnings	—	(2,554)
Payments	—	(2,396)
Transfers In/Out	—	—
Ending Balance	$ 12,400	$ 6,250

Liabilities: Series I Warrants	September 30, 2010	September 30, 2011
Beginning Balance	$ 29,741	$ 14,148
Total (gain) loss included in earnings	(5,877)	(3,059)
Issuance of warrants	—	—
Exercise of warrants	—	—
Transfers In/Out	—	—
Ending Balance	$ 23,864	$ 11,089

Note 19—Recently Adopted Accounting Changes and Recently Issued Accounting Standards

On January 1, 2011, the Company adopted changes issued by the FASB to disclosure requirements for fair value measurements. Specifically, the changes require a reporting entity to disclose, in the reconciliation of fair value measurements using significant unobservable inputs (Level 3), separate information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than as one net number). In addition, the changes require a reporting entity to separately disclose the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers. These changes were applied to the disclosures in note 18 to the Company's condensed consolidated financial statements contained elsewhere herein.

On January 1, 2011, the Company adopted changes issued by the FASB to the testing of goodwill for impairment. These changes permit an entity to make a qualitative assessment of whether it is more likely than not that a reporting unit's fair value is less than its carrying amount before applying the two-step goodwill impairment test. If an entity concludes it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, it need not perform the two-step impairment test. The adoption of this pronouncement did not have any impact on the Company's condensed consolidated financial statements.

On January 1, 2011, the Company adopted changes issued by the FASB to the disclosure of pro forma information for business combinations. These changes clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Also, the existing requirements for supplemental pro forma disclosures were expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The adoption of this pronouncement did not have any impact on the Company's condensed consolidated financial statements.

In May 2011, the FASB issued changes to conform existing guidance regarding fair value measurement and disclosure between GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio, application of premiums and discounts in a fair value measurement, and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. These changes become effective for the Company on January 1, 2012. The Company is currently evaluating the potential impact of these changes on its condensed consolidated financial statements.

In June 2011, the FASB issued changes to the presentation of comprehensive income. These changes give an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The option to present components of other comprehensive income as part of the statement of changes in stockholders' equity was eliminated. The items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income were not changed. Additionally, no changes were made to the calculation and presentation of earnings per share. These changes become effective for the Company on January 1, 2012. The Company is currently evaluating these changes to determine which option will be chosen for the presentation of comprehensive income. Other than the change in presentation, the Company does not believe these changes will have a material impact on its condensed consolidated financial statements.

Note 20—Volumetric Excise Tax Credit ("VETC")

The Company records its VETC credits as revenue in its condensed consolidated statements of operations as the credits are fully refundable and do not need to offset income tax liabilities to be received. VETC revenues for the nine month periods ended September 30, 2010 and 2011 were $0 and $13,441, respectively. The legislation providing for VETC was reinstated in the fourth quarter of 2010, made retroactive to January 1, 2010 and extended to December 31, 2011. During the fourth quarter of 2010, the Company recorded $16,042 of VETC revenue, which included $11,881 related to the nine month period ended September 30, 2010.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following Management's Discussion and Analysis of Financial Condition and Results of Operations (this "MD&A") should be read together with the unaudited condensed consolidated financial statements and the related notes included elsewhere in this report. For additional context with which to understand our financial condition and results of operations, refer to the MD&A for the fiscal year ended December 31, 2010 contained in our 2010 Annual Report on Form 10-K filed with the SEC on March 10, 2011, as well as the consolidated financial statements and notes contained therein.

Cautionary Statement Regarding Forward Looking Statements

This MD&A and other sections of this report contain forward looking statements. We make forward-looking statements, as defined by the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, and in some cases, you can identify these statements by forward-looking words such as "if," "shall," "may," "might," "will likely result," "should," "expect," "plan," "anticipate," "believe," "estimate," "project," "intend," "goal," "objective," "predict," "potential" or "continue," or the negative of these terms and other comparable terminology. These forward-looking statements, which are based on various underlying assumptions and expectations and are subject to risks, uncertainties and other unknown factors, may include projections of our future financial performance based on our growth strategies and anticipated trends in our business. These statements are only predictions *based on our current expectations and projections about future events that we believe to be reasonable. There are important factors that could cause our actual results, level of activity, performance or achievements to differ materially from the historical or future results, level of activity, performance or achievements expressed or implied by such forward-looking statements. These factors include, but are not limited to, those discussed under the caption "Risk Factors" in this report and in our 2010 Annual Report on Form 10-K. In preparing this MD&A, we presume that readers have access to and have read the MD&A in our 2010 Annual Report on Form 10-K pursuant to Instruction 2 to paragraph (b) of Item 303 of Regulation S-K. We undertake no duty to update any of these forward-looking statements after the date of filing of this report to conform such forward-looking statements to actual results or revised expectations, except as otherwise required by law.*

We provide natural gas solutions for vehicle fleets primarily in the United States. Our primary business activity is selling compressed natural gas ("CNG") and liquefied natural gas ("LNG") vehicle fuel to our customers. We also build, operate and maintain fueling stations, manufacture and service advanced natural gas fueling compressors and related equipment, process and sell renewable biomethane and provide natural gas vehicle conversions. Our customers include fleet operators in a variety of markets, such as public transit, refuse hauling, airports, taxis and trucking. In April 2008, we opened our first CNG station in Lima, Peru, through our joint venture, Clean Energy del Peru. In August 2008, we acquired 70% of the outstanding membership interests of Dallas Clean Energy LLC ('DCE"). DCE owns a facility that collects, processes and sells renewable biomethane at the McCommas Bluff landfill in Dallas, Texas. On October 1, 2009, we acquired 100% of BAF Technologies, Inc. ("BAF"), a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles. On September 7, 2010, we completed the purchase of I.M.W. Industries Ltd. ("IMW"), a company that manufactures and services advanced, non-lubricated natural gas fueling compressors and related equipment. On December 15, 2010, we acquired Wyoming Northstar Incorporated, Southstar LLC, and M&S Rental, LLC (collectively "Northstar"), which provides design, engineering, construction and maintenance services for LNG and liquefied to compressed natural gas ("LCNG") fueling stations.

Overview

This overview discusses matters on which our management primarily focuses in evaluating our financial condition and operating performance.

Sources of revenue. We generate a significant portion of our revenue from selling CNG and LNG and providing operations and maintenance services to our customers. The balance of our revenue is provided by designing and constructing natural gas fueling stations, financing our customers' natural gas vehicle purchases, sales of pipeline quality biomethane produced by DCEMB, sales of natural gas vehicle conversions through our wholly owned subsidiary BAF, and commencing on September 7, 2010, sales of advanced natural gas fueling compressors and related equipment and maintenance services through IMW. In addition, on December 15, 2010, we began generating revenue from LNG and LCNG fueling station design, engineering, construction and maintenance services through Northstar.

Key operating data. In evaluating our operating performance, our management focuses primarily on: (1) the amount of CNG and LNG gasoline gallon equivalents delivered (which we define as (i) the volume of gasoline gallon equivalents we sell to our customers, plus (ii) the volume of gasoline gallon equivalents dispensed to our customers at stations where we provide operating and maintenance ("O&M") services, but do not directly sell the CNG or LNG, plus (iii) our proportionate share of the gasoline gallon equivalents sold as CNG by our joint venture in Peru, plus (iv) our proportionate share of the gasoline gallon equivalents of biomethane produced and sold as pipeline quality natural gas by DCEMB), (2) our gross margin (which we define as revenue minus cost of sales), and (3) net income (loss). The following table, which you should read in conjunction with our condensed consolidated financial statements and notes contained elsewhere in this quarterly report on Form 10-Q and our consolidated financial statements and notes contained in our annual report on Form 10-K for the year ended December 31, 2010, presents our key operating data for the years ended December 31, 2008, 2009, and 2010 and for the three and nine months ended September 30, 2010 and 2011:

Gasoline gallon equivalents delivered (in millions)	**Year Ended December 31, 2008**	**Year Ended December 31, 2009**	**Year Ended December 31, 2010**	**Three Months Ended September 30, 2010**	**Three Months Ended September 30, 2011**	**Nine Months Ended September 30, 2010**	**Nine Months Ended September 30, 2011**
CNG	47.6	67.9	81.4	20.2	26.8	60.0	75.1
Biomethane	2.0	6.4	7.4	1.8	1.8	5.6	5.0
LNG	23.9	26.7	33.9	9.3	12.3	25.4	35.5
Total	73.5	101.0	122.7	31.3	40.9	91.0	115.6
Operating data							
Gross margin	$ 27,099	$ 48,582	$ 69,945	$ 12,145	$ 19,328	$ 36,995	$ 56,354
Net loss	(44,463)	(33,249)	(2,516)	(1,830)	(11,354)	(16,302)	(26,726)

Key trends in 2008, 2009, 2010. According to the U.S. Energy Information Administration, demand for natural gas fuels in the United States increased by approximately 26% during the period January 1, 2008 through December 31, 2010. We believe this growth in demand was attributable primarily to the rising prices of gasoline and diesel relative to CNG and LNG during these periods and increasingly stringent environmental regulations affecting vehicle fleets.

The number of fueling stations we served grew from 147 at December 31, 2004 to 257 at September 30, 2011 (a 74.8% increase). Included in this number are all of the CNG and LNG fueling stations we own, maintain or with which we have a fueling supply contract. The amount of CNG and LNG gasoline gallon equivalents we delivered from 2005 to 2010 increased by 116%. The increase in gasoline gallon equivalents delivered was the primary contributor to increased revenues during these periods. Our cost of sales also increased during these periods, which was attributable primarily to increased costs related to delivering more CNG and LNG to our customers.

During the last half of 2009, during 2010, and during the first nine months of 2011, we experienced reduced margins related to our fueling business compared to historical margins. The reduction in margins is primarily a result of increased O&M volumes with our transit customers, that have lower margins, becoming a larger part of our overall fueling business. We believe that our margins on fuel sales will improve in the future to the extent we are successful in increasing our retail CNG and LNG fueling operations as an overall component of our fueling business. Within our overall fueling business, we earn our highest margins in our retail fueling operations.

During the first nine months of 2011, prices for gasoline, diesel fuel and natural gas generally increased. In California, average retail prices for gasoline have increased from a low of $3.36 per gallon in January 2011 to $3.93 per gallon at September 30, 2011, and average retail prices for diesel fuel have increased from a low of $3.51 per diesel gallon in January 2011 to $4.04 per diesel gallon at September 30, 2011. Higher gasoline and diesel prices typically improve our margins on fuel sales to the extent we price fuel at a discount to gasoline or diesel. During this time period, the price for natural gas slightly increased. The NYMEX price for natural gas fluctuated from a low of $3.79 per MMbtu in March 2011 to a high of $4.38 per MMbtu in May and August 2011. Our average retail prices for LNG fuel in the Los Angeles metropolitan area decreased from $2.50 per diesel gallon equivalent in January 2011 to $2.40 per diesel gallon equivalent at September 30, 2011, and our CNG fuel sold in the Los Angeles metropolitan area increased from a low of $2.60 per gasoline gallon equivalent in January 2011 to a high of $2.75 per gasoline gallon equivalent at September 30, 2011.

Anticipated future trends. We anticipate that, over the long term, the prices for gasoline and diesel will continue to be higher than the price of natural gas as a vehicle fuel, and more stringent emissions requirements will continue to make natural gas vehicles an attractive alternative to traditional gasoline and diesel powered vehicles. Our belief that natural gas will continue, over the long term, to be a cheaper vehicle fuel than gasoline or diesel is based in part on the growth in U.S. natural gas production and supply. A 2008 Navigant Consulting, Inc. study indicates that as a result of new unconventional gas shale discoveries from 22 basins in the U.S., maximum estimates of total recoverable domestic reserves from producers have increased to equal 118 years of U.S. production at 2007 production levels. The study indicated a mean level of reserves equal to 88 years of supply at 2007 production levels. According to the report, shale gas production growth from only the major six shale resources in the U.S., plus the Marcellus shale, could reach 27 billion cubic feet per day and as high as 39 billion cubic feet per day by 2015. Navigant has also indicated that development of the shale resources base has resulted in a substantial surplus of natural gas compared to demand of as much as 11 billion cubic feet per day. These current surplus levels are 18% of annual average historical U.S. consumption levels of approximately 20 Tcf per year; providing sufficient gas supply to meet the requirements of all existing markets and to meet new market requirements. Based on analyst reports, we believe that there is a significant worldwide supply of natural gas relative to crude oil as well. According to the 2010 BP Statistical Review of World Energy, on a global basis, the ratio of proven natural gas reserves to 2009 natural gas production was 37% greater than the ratio of proven crude oil reserves to 2009 crude oil production. This analysis suggests significantly greater long term availability of natural gas than crude oil based on current consumption.

We believe there will be significant growth in the consumption of natural gas as a vehicle fuel among vehicle fleets, and our goal is to capitalize on this trend and enhance our leadership position as this market expands. With our recent acquisitions of IMW and Northstar, we are now a fully integrated provider of advanced compression technology, station-building and fueling. We have built natural gas fueling stations, and plan to build additional natural gas fueling stations, that will provide LNG to fleet vehicles at the Ports of Los Angeles and Long Beach and for other regional corridors throughout the United States. Further, we plan to enhance our market leadership position by building a network of LNG truck fueling stations to form the backbone of America’s natural gas highway. We also anticipate expanding our sales of CNG and LNG in the other markets in which we operate, including trucking, refuse hauling, airports and public transit. Consistent with the anticipated growth of our business, we also expect that our operating costs and capital expenditures will increase, primarily from the anticipated expansion of our station network or LNG production capacity, as well as the logistics of delivering more CNG and LNG to our customers. We also anticipate that we will continue to seek to acquire assets and/or businesses that are in the natural gas fueling infrastructure or biomethane production business that may require us to raise additional capital. Additionally, we have and will continue to increase our sales and marketing team and other necessary personnel as we seek to expand our existing markets and enter new markets, which will also result in increased costs. Further, we expect to experience increased competition from oil companies, station owners, industrial gas companies, natural gas utilities and other competitors who enter the market for CNG and LNG vehicle fuels, and we anticipate that increased competition will result in higher operating costs and capital expenditures.

Continuing high unemployment rates and reduced economic activity may reduce our opportunities to attract new fleet customers. Many governmental entities are experiencing significant budget deficits as a result of the economic recession and have been, and may continue to be, unable to invest in new natural gas vehicles for their transit or refuse fleets or may be compelled to reduce public transportation and services, or the prices they pay for these services, which would negatively affect our business.

Sources of liquidity and anticipated capital expenditures. Liquidity is the ability to meet present and future financial obligations either through operating cash flows, the sale or maturity of existing assets, or by the acquisition of additional funds through capital management. Historically, our principal sources of liquidity have consisted of cash provided by operations and financing activities.

Our business plan calls for approximately $18.8 million in capital expenditures from October 1, 2011 through the end of 2011, primarily related to construction of new fueling stations and our biomethane project outside of Detroit, Michigan. This amount excludes (i) the capital expenditures related to LNG fueling station construction to be funded by the proceeds of our July 2011 financing transaction with Chesapeake, and (ii) the capital expenditures DCEMB will make at its landfill gas processing facility with the proceeds it received on March 31, 2011 when it completed its bond offering. We may also elect to invest additional amounts in expansion of our California LNG plant or for other acquisitions or investments in companies or assets in the natural gas fueling infrastructure, services and production industries, including biomethane production. At September 30, 2011, we had total cash and cash equivalents of $159.0 million, and we will need to raise additional capital as necessary to fund any expansion of our California LNG plant, acquisitions or other capital expenditures or investments that we cannot fund through available cash, cash generated by operations, or the potential exercise of a warrant for 15,000,000 shares of our common stock at an exercise price of $10 per share held by Boone Pickens. The timing and necessity of any future capital raise will depend on our rate of new station construction, which may be affected by any federal legislation that provides incentives for natural gas vehicle purchases and fuel use, any decision to expand our California LNG plant or to invest in additional biomethane production facilities or other opportunities in the natural gas fueling industry, and potential merger or acquisition activity. For more information, see “Liquidity and Capital Resources” and “Capital Expenditures” below. We may not be able to raise capital on terms that are favorable to existing stockholders or at all. Any inability to raise capital may impair our ability to invest in new stations, develop natural gas fueling infrastructure, invest in strategic transactions or acquisitions, expand biomethane production and reduce our ability to grow our business and generate increased revenues.

Business risks and uncertainties. Our business and prospects are exposed to numerous risks and uncertainties. For more information, see “Risk Factors” in Part II, Item 1A of this report.

Operations

We generate revenues principally by selling CNG and LNG and providing O&M services to our vehicle fleet customers. For the nine months ended September 30, 2011, CNG and biomethane (together) represented 69% and LNG represented 31% of our natural gas sales (on a gasoline gallon equivalent basis). To a lesser extent, we generate revenues by designing and constructing fueling stations and selling or leasing those stations to our customers. We also generate material revenues through sales of biomethane produced by our joint venture subsidiary DCEMB, sales of natural gas vehicle systems by our wholly owned subsidiary BAF, sales of advanced natural gas fueling compressors and related equipment and maintenance services through IMW, and sales of LNG and LCNG fueling station design, construction and O&M services through Northstar. The significant portions of our operating and maintenance revenues are generated from CNG stations, and substantially all of our station sale and leasing revenues have been generated from CNG stations.

CNG Sales

We sell CNG through fueling stations located on our customers’ properties and through our network of public access fueling stations. At these CNG fueling stations, we procure natural gas from local utilities or brokers under standard, floating-rate arrangements and then compress and dispense it into our customers’ vehicles. Our CNG sales are made primarily through contracts with our fleet customers. Under these contracts, pricing is determined primarily on an index-plus basis, which is calculated by adding a margin to the local index or utility price for natural gas. CNG sales revenues based on an index-plus methodology increase or decrease as a result of an increase or decrease in the price of natural gas. We also sell a small amount of CNG under fixed-price contracts. We will continue to offer fixed price contracts as appropriate and consistent with our natural gas hedging policy that was revised in May 2008. Our fleet customers typically are billed monthly based on the volume of CNG sold at a station. The remainder of our CNG sales are on a per fill-up basis at prices we set at the pump based on prevailing market conditions. These customers typically pay using a credit card at the station.

LNG Sales

We sell substantially all of our LNG to fleet customers, who typically own and operate their fueling stations. We also sell LNG to customers at our five public LNG stations and for non-vehicle use. During 2011, we procured 42% of our LNG from third-party producers, and we produced the remainder of the LNG at our liquefaction plants in Texas and California. For LNG that we purchase from third parties, we may enter into “take or pay” contracts that require us to purchase minimum volumes of LNG at index-based rates. We deliver LNG via our fleet of 58 tanker trailers to fueling stations, where it is stored and dispensed in liquid form into vehicles. We sell LNG principally through supply contracts that are priced on either a fixed-price or index-plus basis. LNG sales revenues based on an index-plus methodology increase or decrease as a result of an increase or decrease in the price of natural gas. We will continue to offer fixed price contracts as appropriate and consistent with our natural gas hedging policy that was revised in May 2008. Our LNG contracts provide that we charge our customers periodically based on the volume of LNG supplied or sold.

America’s Natural Gas Highway

We plan to build and operate a network of LNG fueling stations at strategic truck stop locations along major trucking corridors in the United States. We anticipate that these fueling stations will form the backbone of America’s natural gas highway, and expect to use the proceeds of our July 2011 financing transaction with Chesapeake to help fund the cost of building the stations. We expect to generate revenue through sales of natural gas fuel to operators of heavy duty trucks and other vehicles at these planned fueling stations.

Government Incentives

Since October 1, 2006, we have received a federal fuel tax credit (“VETC”) of $0.50 per gasoline gallon equivalent of CNG and $0.50 per liquid gallon of LNG that we sold as vehicle fuel. Based on the service relationship with our customers, either we or our customers were able to claim the credit. We recorded these tax credits as revenues in our consolidated statements of operations as the credits are fully refundable and do not need to offset tax liabilities to be received. As such, the credits are not deemed income tax credits under the accounting guidance applicable to income taxes. In addition, we believe the credits are properly recorded as revenue because we often incorporate the tax credits into our pricing with our customers, thereby lowering the actual price per gallon we charge them. The program providing for the VETC expires on December 31, 2011.

On July 15, 2010, the IRS sent us a letter (i) disallowing approximately $5.1 million related to certain claims we made from October 1, 2006 to June 30, 2008 under the Volumetric Excise Tax Credit program, and (ii) seeking repayment of such amount. We believe our claims were properly made and are contesting the IRS’s determination.

Operation and Maintenance

We generate a significant portion of our revenue from operation and maintenance agreements for CNG fueling stations where we do not supply the fuel. We refer to this portion of our business as “O&M.” At these fueling stations, the customer contracts directly with a local broker or utility to purchase natural gas. For O&M services, we do not sell the fuel itself, but generally charge a per-gallon fee based on the volume of fuel dispensed at the station. We include the volume of fuel dispensed at the stations at which we provide O&M services in our calculation of aggregate gasoline gallon equivalents sold. Through Northstar, we also generate O&M revenues for LNG fueling stations. In these instances, we may or may not also supply LNG to the station.

Station Construction

We generate a small portion of our revenue from designing and constructing fueling stations and selling or leasing the stations to our customers. For these projects, we act as general contractor or supervise qualified third-party contractors. We charge construction fees or lease rates based on the size and complexity of the project.

On December 15, 2010, we completed the purchase of Northstar, an entity that provides design, engineering, construction and maintenance services for LNG and LCNG fueling stations. For the nine months ended September 30, 2011, Northstar contributed approximately $7.6 million to our revenue.

Vehicle Acquisition and Finance

In 2006, we commenced offering vehicle finance services for some of our customers' purchases of natural gas vehicles or the conversion of their existing gasoline or diesel powered vehicles to operate on natural gas. We loan to certain qualifying customers a portion of, and on occasion up to 100% of, the purchase price of their natural gas vehicles. We may also lease vehicles in the future. Where appropriate, we apply for and receive state and federal incentives associated with natural gas vehicle purchases and pass these benefits through to our customers. We may also secure vehicles to place with customers or pay deposits with respect to such vehicles prior to receiving a firm order from our customers, which we may be required to purchase directly if our customer fails to purchase the vehicle as anticipated. Through September 30, 2011, we have not generated significant revenue from vehicle finance activities.

Landfill Gas

In August 2008, we acquired 70% of the outstanding membership interests of DCE for a purchase price of $19.6 million including transaction costs. DCE's subsidiary, DCEMB, owns a facility that collects, processes and sells biomethane from the McCommas Bluff landfill located in Dallas, Texas. For the nine months ended September 30, 2010 and 2011, DCE generated approximately $8.5 million and $9.0 million, respectively, in revenue from sales of biomethane, all of which is included in our condensed consolidated statements of operations.

On April 3, 2009, DCE entered into a fifteen year gas sale agreement with Shell Energy North America (US), L.P. ("Shell") for the sale by DCE to Shell of biomethane produced by DCE's landfill gas processing facility (the "Shell Gas Sale Agreement").

DCE retains the right to reserve from the Shell Gas Sale Agreement up to 500 MMBtus per day of biomethane for sale as a vehicle fuel. To the extent that DCE produces volumes of biomethane in excess of the volumes sold under the agreement, DCE will either attempt to sell such volumes at then-prevailing market prices or seek to enter into another gas sale agreement in the future. There is no guarantee that DCE will produce or be able to sell up to the maximum volumes called for under the agreement, and DCE's ability to produce such volumes of biomethane is dependent on a number of factors beyond DCE's control including, but not limited to, the availability and composition of the landfill gas that is collected, the impact on DCE's operations of the operation of the landfill by the City of Dallas, the reliability of the processing plant's critical equipment, and weather conditions. The processing equipment is currently being expanded and upgraded, which may result in significant down time to complete the work, which consequently may reduce DCE's sales of biomethane during the period of expansion and upgrade work. The expansion and upgrade work is anticipated to continue into the first half of 2012.

The sale price for the gas under the Shell Gas Sale Agreement is fixed. The sale price for the gas represents a substantial premium to the current prevailing prices for natural gas at September 30, 2011.

The Shell Gas Sale Agreement is terminable by either party on thirty days' written notice if the California Energy Commission makes a written determination or adopts a ruling or regulation that the biomethane sold under the agreement will, from the date of such ruling or regulation, no longer qualify as a California Renewable Portfolio Standard eligible fuel. In addition, Shell has the right to terminate the agreement upon thirty days' written notice if the volumes of biomethane produced and delivered, calculated monthly on a rolling two-year average, are less than an annual average of 630,720 MMBtu per year (or 2,083 MMBtu per day).

On March 25, 2011, DCE's subsidiary, Dallas Clean Energy McCommas Bluff, LLC, a Delaware limited liability company ("DCEMB"), arranged for a $40.2 million tax-exempt bond issuance (the "Revenue Bonds"). The Revenue Bonds will be repaid from the revenue generated by DCEMB from the sale of renewable natural gas (or biomethane). The Revenue Bonds are secured by the revenue and assets of DCEMB and are non-recourse to DCEMB's direct and indirect parent companies, including us. The bond repayments are amortized through December 2024 and the average coupon interest rate on the bonds is 6.60%. The bond issuance closed March 31, 2011.

The bond proceeds will primarily be used to finance further improvements and expansion of the DCEMB landfill gas processing facility. A portion of the proceeds were used to retire the DCE Loan. The Company, in turn, used the proceeds from the payoff of the DCE Loan to repay approximately $8.0 million we owed to PCB under the Facility B Loan on March 31, 2011.

Pursuant to the Loan Agreement, dated as of January 1, 2011 (the "Loan Agreement"), between DCEMB and the Mission Economic Development Corporation (the "Issuer"), DCEMB has covenanted with the Issuer to make loan repayments equal to the principal and interest coming due on the Revenue Bonds. Pursuant to the Trust Indenture, dated as of January 1, 2011 (the "Indenture"), the Issuer has pledged and assigned to the Trustee all of the Issuer's right, title and interest in and to the Loan Agreement (with certain specified exceptions) and the Note described below. DCEMB executed a promissory note, dated March 31, 2011 (the "Note"), as evidence of its obligations under the Loan Agreement.

The obligations of DCEMB under the Loan Agreement are secured by a Leasehold Deed of Trust, Assignment of Rents, Security Agreement and Fixture Filing, dated as of January 1, 2011 (the "Deed of Trust"), executed by DCEMB in favor of the deed of trust trustee named therein for the benefit of the Bank of New York Mellon Trust Company, N.A., a Trustee (the "Trustee"). In addition, DCEMB executed a Security Agreement (the "Security Agreement"), as security for its obligations, pursuant to which DCEMB granted to the Trustee a security interest in all right, title and interest of DCEMB to the Collateral (as defined in the Security Agreement), which includes, but is not limited to, DCEMB's rights, title and interest in any gas sale agreements, including the Shell Gas Sale Agreement, and the funds and accounts held under the Indenture.

Pursuant to a Consent and Agreement, by and between Shell Energy, The Bank of New York Mellon Trust Company, N.A., as Depository Bank, (the "Depository Bank"), DCEMB and the Trustee, dated as of January 1, 2011 (the "Consent Agreement"), Shell Energy agreed to make all payments due to DCEMB under the Shell Gas Sale Agreement to the Depository Bank. In addition, other revenues generated through the sale of gas produced at the facility will be paid directly to the Depository Bank pursuant to a Depository and Control Agreement, dated as of January 1, 2011 (the "Depository Agreement"), among DCEMB, the Trustee and the Depository Bank.

All payments received by the Depository Bank will be placed into various accounts in accordance with the requirements of the Indenture and the Depository Agreement. The funds in these accounts will be used to service required debt payments, finance further improvements and expansion of the landfill gas processing facility owned by DCEMB, finance the operations and maintenance of DCEMB, finance certain expenses associated with setting up and maintaining the accounts, and other uses as prescribed in the Depository Agreement. The Depository Bank will make payments out of these accounts in accordance with the requirements of the Depository Agreement. At the end of each month after all required account fundings have been fulfilled in accordance with the Depository Agreement, all remaining excess funds will be placed into a Surplus Account. The funds in the Surplus Account will be delivered to DCEMB so long as (i) DCEMB's Debt Service Coverage Ratio (as defined) for the most recent four calendar quarters then ended equals or exceeds 1.25:1, (ii) DCEMB's Debt Service Coverage Ratio (as defined) is reasonably projected to equal or exceed 1.25:1 for the next four calendar quarters, (iii) no events of default have occurred as defined by the Indenture and the Loan Agreement, and (iv) after giving effect to the transfer, DCEMB's Minimum Days Cash on Hand (as defined) shall be, or shall at any time be projected to be, more than the lesser of thirty-five Days Cash on Hand (as defined) or $1.3 million. Due to these restrictions on this cash, we have classified all of this cash as restricted cash on the balance sheet. We record the restricted cash that is expected to be received and used within the next 12 months from the Depository Bank for working capital and operating purposes as current in our balance sheet, and present the remaining balance as non-current in the line item notes receivable and other long term assets. At September 30, 2011, $20.8 million was included as long term restricted cash and $4.5 million was included in short term restricted cash in the accompanying condensed consolidated balance sheet.

The Indenture and the Loan Agreement have certain non-financial debt covenants with which DCEMB must comply. As of September 30, 2011, DCEMB was in compliance with all such debt covenants.

Pursuant to a collateral assignment and Consent and Agreement with Atmos Pipeline - Texas ("Atmos"), DCEMB has collaterally assigned to the Trustee, subject to certain reserved rights and the consent of Atmos, the transportation agreements of the Company with Atmos.

Vehicle Conversions

On October 1, 2009, we purchased all of the outstanding shares of BAF. Founded in 1992, BAF provides natural gas vehicle ("NGV") conversions, alternative fuel systems, application engineering, service and warranty support and research and development services. BAF's vehicle conversions include taxis, vans, pick-up trucks and shuttle buses. BAF utilizes advanced natural gas system integration technology and has certified NGVs under both EPA and CARB standards achieving Super Ultra Low Emission Vehicle emissions. We generate revenues through the sale of natural gas vehicle conversion systems that allow gasoline and diesel vehicles to run on natural gas. The majority of BAF's revenue during 2010 was derived from sales of converted natural gas service vans to AT&T and Verizon. During the first nine months of 2010 and 2011, BAF contributed approximately $29.3 million and $18.8 million, respectively, to our revenue.

Natural Gas Fueling Compressors

On September 7, 2010, we completed our purchase of IMW. IMW manufactures and services advanced, non-lubricated natural gas fueling compressors and related equipment for the global natural gas fueling market. IMW is headquartered near Vancouver, British Columbia, and has other manufacturing facilities near Shanghai, China and in Ferndale, Washington, and has sales and service offices in Bangladesh, Columbia, Peru and the United States. For the nine months ended September 30, 2010 and 2011, IMW contributed approximately $3.3 million and $46.5 million, respectively, to our revenue.

Volatility of Earnings and Cash Flows

Our earnings and cash flows historically have fluctuated significantly from period to period based on our futures activities, as all of our futures contracts entered into prior to June 30, 2008 have not qualified for hedge accounting under the relevant derivative accounting guidance. We have therefore recorded any changes in the fair market value of these contracts that did not qualify for hedge accounting directly in our statements of operations in the line item derivative (gains) losses along with any realized gains or losses generated during the period. We experienced a derivative loss of $0.3 million in the year ended December 31, 2008. Subsequent to June 30, 2008, our futures contracts did qualify for hedge accounting, so we had no derivative gains or losses in the years ended December 31, 2009 and 2010 and during the nine month period ended September 30, 2011 related to our futures contracts. In accordance with our natural gas hedging policy, we plan to structure all subsequent futures contracts as cash flow hedges under the applicable derivative accounting guidance, but we cannot be certain that they will qualify. See "Risk Management Activities" below. If the futures contracts do not qualify for hedge accounting, we could incur significant increases or decreases in our earnings based on fluctuations in the market value of the contracts from period to period.

Additionally, we are required to maintain a margin account to cover losses related to our natural gas futures contracts. Futures contracts are valued daily, and if our contracts are in loss positions at the end of a trading day, our broker will transfer the amount of the losses from our margin account to a clearinghouse. If at any time the funds in our margin account drop below a specified maintenance level, our broker will issue a margin call that requires us to restore the balance. Consequently, these payments could significantly impact our cash balances. At September 30, 2011, we had $3.6 million on deposit in margin accounts, which are included in prepaid expenses and other current assets and notes receivable and other long-term assets in our balance sheet.

The decrease in the value of our futures positions and any required margin deposits on our futures contracts that are in a loss position could significantly impact our financial condition in the future.

Volatility of Earnings Related to Series I Warrants

Beginning January 1, 2009, under Financial Accounting Standards Board ("FASB") authoritative guidance, we have been required to record the change in the fair market value of our Series I warrants in our consolidated financial statements. We recognized a gain of $5.9 million and $3.1 million related to recording the fair market value changes of our Series I warrants in the nine months ended September 30, 2010 and 2011, respectively. See note 18 to our condensed consolidated financial statements contained elsewhere herein. Our earnings or loss per share may be materially impacted by future gains or losses we are required to record as a result of valuing our Series I warrants. On November 10, 2010, 1,183,712 of the Series I warrants were exercised and are no longer outstanding. As of September 30, 2011, 2,130,682 of the Series I warrants remained outstanding.

Volatility of Earnings Related to Contingent Consideration

Under recent business combination accounting guidance, we are required to record the change in the value of the contingent consideration related to our acquisitions of both BAF and IMW in our financial statements through the contingency period, which expires December 31, 2011 for BAF and March 31, 2014 for IMW.

If the anticipated results of BAF or IMW increase or decrease during future periods, we may be required to recognize material losses or gains based on the valuation of the increased or decreased consideration due to the former BAF and IMW shareholders. To record the change in value of the BAF contingent consideration, we recognized a gain of $0.5 million during the nine months ended September 30, 2010 and we recognized a gain of $0.4 million during the nine months ended September 30, 2011. To record the change in the value of the IMW contingent consideration, we recognized a gain of $2.2 million during the nine months ended September 30, 2011.

Debt Compliance

Pursuant to our acquisition of IMW, our credit agreement with HSBC also requires that IMW complies with certain financial covenants as detailed in note 12 of our condensed consolidated financial statements contained elsewhere herein. Among those financial covenants are that IMW shall not permit 1) its ratio of debt to tangible net worth to be greater than 4.0 to 1.0 until December 31, 2011, and greater than 3.75 to 1.0 from January 1, 2012 through March 31, 2012, and greater than 3.5 to 1.0 from April 1, 2012 through June 30, 2012, and greater than 3.0 to 1.0 on or after July 1, 2012, 2) its tangible net worth to at anytime be below CAD$7,000 and 3) its ratio of current assets to current liabilities to be less than 1.15 to 1.0 until March 31, 2012 and less than 1.25 to 1.0 on or after April 1, 2012. Should IMW's operating results not materialize as planned, we could violate these covenants. If we were to violate a covenant, we would seek a waiver from the bank, which the bank is not obligated to grant. If the bank were to decline to grant a waiver, all of the obligations under the credit agreement would be due and payable. IMW was in compliance with these covenants as of September 30, 2011.

The Indenture and the Loan Agreement DCEMB entered into as part of issuing its Revenue Bonds have certain non-financial debt covenants that DCEMB must comply with. As of September 30, 2011, DCEMB was in compliance with its debt covenants.

The Loan Agreement we entered into as part of issuing the CHK Note has certain non-financial debt covenants that we must comply with. As of September 30, 2011, we were in compliance with these debt covenants.

The Convertible Note Purchase Agreements we entered into as part of issuing the SLG Notes have certain non-financial debt covenants that we must comply with. As of September 30, 2011, we were in compliance with these covenants.

Risk Management Activities

Our risk management activities, including the revised natural gas hedging policy adopted by our board of directors in February 2007 and revised by our board of directors on May 29, 2008, are discussed in Part II, Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operation) of our 2010 Annual Report on Form 10-K. For the quarter ended September 30, 2011, there were no material changes to our risk management activities.

Critical Accounting Policies

For the nine months ended September 30, 2011, there were no material changes to the "Critical Accounting Policies" discussed in Part II, Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) of our 2010 Annual Report on Form 10-K.

Recently Issued Accounting Pronouncements

For a description of recently issued accounting pronouncements, see note 19 to our condensed consolidated financial statements contained elsewhere herein.

Results of Operations

The following is a more detailed discussion of our financial condition and results of operations for the periods presented as a percentage of total revenues:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2011	2010	2011
Statement of Operations Data:				
Revenue:				
Product revenues	89.8%	89.1%	89.1%	89.2%
Service revenues	10.2	10.9	10.9	10.8
Total revenues	100.0	100.0	100.0	100.0
Operating expenses:				
Cost of sales:				
Product cost of sales	68.3	67.8	66.4	67.6
Service cost of sales	5.1	5.4	4.9	5.1
Derivative gains on Series I warrant valuation	(17.2)	(2.1)	(4.6)	(1.5)
Selling, general and administrative	34.7	27.9	34.5	29.0
Depreciation and amortization	12.1	10.5	12.1	10.8
Total operating expenses	103.0	109.5	113.3	111.0
Operating loss	(3.0)	(9.5)	(13.3)	(11.0)
Interest income (expense), net	(0.2)	(4.4)	0.0	(2.7)
Other expense	(0.7)	(3.4)	(0.3)	(0.8)
Income from equity method investments	0.2	0.1	0.2	0.2
Loss before income taxes	(3.7)	(17.2)	(13.4)	(14.3)
Income tax (expense) benefit	(0.6)	1.3	0.7	1.4
Net loss	(4.3)	(15.9)	(12.7)	(12.9)
Loss (income) of noncontrolling interest	0.2	0.1	0.0	(0.0)
Net loss attributable to Clean Energy Fuels Corp.	(4.1)	(15.8)	(12.7)	(12.9)

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010

Revenue. Revenue increased by $26.4 million to $72.1 million in the three months ended September 30, 2011, from $45.7 million in the three months ended September 30, 2010. A portion of this increase was the result of an increase in the number of gallons delivered from 31.3 million gasoline gallon equivalents to 40.9 million gasoline gallon equivalents. Our net increase in CNG volume was primarily from six new stations for an existing refuse customer, five new stations for an existing transit customer, three new refuse customers, two new transit customers and one new airport customer, which together accounted for 6.8 million gallons of the CNG volume increase. We also experienced an increase of 2.0 million gallons in CNG volume between periods from our existing airport, transit and refuse customers, and volume growth from our share of our joint venture in Peru. These CNG volume increases were offset by a 2.2 million gallons decrease related to the loss of two transit customers. We also experienced a net increase of 3.0 million gallons in LNG volume between periods, which was primarily from a 3.5 million gallon increase from Northstar O&M services. The LNG volume increase was offset by a 0.5 million gallons decrease from existing transit customers. We experienced a $6.9 million increase, excluding Northstar, in station construction revenues between periods, primarily due to the completion of three new CNG stations for one refuse customer, one new CNG station for a trucking customer, one CNG station upgrade for a new transit customer, and the sale of a CNG station upgrade to one of our existing transit customers. Our acquisitions of IMW on September 7, 2010 and Northstar on December 15, 2010 contributed $12.5 million and $1.9 million, respectively, to our increased revenue between periods. Revenue attributable to the VETC also increased between periods as we recorded $4.5 million of revenue related to fuel tax credits in the third quarter of 2011. We did not record any revenue related to fuel tax credits in the third quarter of 2010 as the fuel tax credits were not reinstated until the fourth quarter of 2010. These increases were offset by the decrease in our effective price per gallon that we charged to our customers between periods. Our effective price per gallon was $0.86 in the three months ended September 30, 2011, which represents a $0.14 per gallon decrease from $1.00 in the three months ended September 30, 2010. The decrease was primarily due to a higher percentage of O&M contracts in the third quarter of 2011, which generate less revenue per gallon than contracts where we supply the natural gas commodity. Revenue also decreased by $3.1 million between periods due to decreased sales of natural gas vehicle equipment by BAF.

Cost of sales. Cost of sales increased by $19.3 million to $52.8 million in the three months ended September 30, 2011, from $33.5 million in the three months ended September 30, 2010. Our cost of sales primarily increased between periods as a result of delivering more volume to our customers. Our acquisition of IMW on September 7, 2010 and Northstar on December 15, 2010 contributed $12.1 million and $1.0 million, respectively, to our increased cost of sales between periods. We also experienced a $6.0 million increase, excluding Northstar, in station construction costs between periods. These increases were offset by the decrease in our effective cost per gallon of $0.11 per gallon, to $0.62 per gallon, in the three months ended September 30, 2011. This decrease was primarily the result of a higher percentage of O&M contracts in the third quarter of 2011 that are included in our volume totals but do not increase our cost of sales amount significantly as we do not pay for the natural gas consumed at the properties. We also experienced a $2.3 million decrease in costs related to BAF's vehicle equipment sales between periods, as BAF's sales of natural gas vehicle equipment decreased.

Derivative (gain) loss on Series I warrant valuation. Derivative gain decreased by $6.4 million to $1.5 million in the three months ended September 30, 2011, from $7.9 million in the three months ended September 30, 2010. The amounts represent the non-cash impact attributable to valuing our outstanding Series I warrants based on the required mark-to-market accounting for the warrants (see note 18 to our condensed consolidated financial statements contained elsewhere herein) during the three month periods ended September 30, 2010 and 2011.

Selling, general and administrative. Selling, general and administrative expenses increased by $4.2 million to $20.1 million in the three months ended September 30, 2011, from $15.9 million in the three months ended September 30, 2010. A significant portion of this increase was the result of our salaries and benefits expense increasing by $3.2 million between periods as we increased our employee headcount from 622 at September 30, 2010 to 937 at September 30, 2011. We also experienced a $1.2 million increase in occupancy costs, business insurance, employee recruiting, bank and credit card fees, and general office expenses related to our continued business growth and our acquisitions of IMW and Northstar during the third and fourth quarters of 2010. During the third quarter of 2011, we incurred $0.8 million of costs related to developing new engine products for BAF. Our travel and entertainment expenses increased $0.4 million between periods, primarily due to the increased travel of our sales team. Offsetting these increases was a decrease of $1.4 million during the third quarter of 2011 related to a decrease in the IMW and BAF contingent consideration liabilities.

Depreciation and amortization. Depreciation and amortization increased by $2.1 million to $7.6 million in the three months ended September 30, 2011, from $5.5 million in the three months ended September 30, 2010. This increase was primarily due to additional depreciation expense in the three months ended September 30, 2011 related to increased property and equipment balances between periods, primarily related to our expanded station network. Our September 30, 2011 amortization expense also includes increased amortization of the intangible assets we obtained in connection with our acquisition of Northstar in the fourth quarter of 2010.

Interest income (expense), net. Interest income (expense), net, increased by $3.1 million to $3.2 million of expense for the three months ended September 30, 2011. This increase was primarily the result of an increase in interest expense in the three months ended September 30, 2011 related to debt we incurred in connection with the acquisition of Northstar, and interest expense related the DCEMB's revenue bonds that closed March 31, 2011 (see note 12 to our condensed consolidated financial statements contained elsewhere herein). We also incurred increased interest expense between periods related to the $200.0 million of debt securities we issued in July and August of 2011.

Other income (expense), net. Other income (expense), net, increased by $2.1 million to $2.5 million of expense for the three months ended September 30, 2011. This increase was primarily due to the impact of foreign currency exchange losses on the notes we issued as part of the IMW acquisition.

Income from equity method investment. There was no significant change in income from equity method investments between the three months ended September 30, 2010 and the three months ended September 30, 2011.

Loss (income) of noncontrolling interest. There was no significant change in loss (income) of noncontrolling interest between the three months ended September 30, 2010 and the three months ended September 30, 2011. The noncontrolling interest represents the 30% interest in DCEMB held by our joint venture partner.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Revenue. Revenue increased by $77.8 million to $206.5 million in the nine months ended September 30, 2011, from $128.7 million in the nine months ended September 30, 2010. A portion of this increase was the result of an increase in the number of gallons delivered from 91.0 million gasoline gallon equivalents to 115.6 million gasoline gallon equivalents. Our net increase in CNG volume was primarily from eight new stations for an existing refuse customer, five new stations for an existing transit customer, four new refuse customers, four new transit customers, and three new airport customers, which together accounted for 18.8 million gallons of the CNG volume increase. The volume growth from our existing airport, refuse and transit customers, combined with the volume growth from our share of our joint venture in Peru, contributed 5.1 million gallons of the CNG volume increase. These CNG volume increases were offset by a 8.8 million gallon decrease related to the loss of two transit customers. We also experienced a net increase of 10.1 million gallons in LNG volume between periods, which was primarily due to 10.0 million gallons from Northstar O&M services. We also experienced a decrease of 0.6 million gallons in biomethane volume between periods, primarily due to adverse weather conditions. We experienced a $16.0 million increase, excluding Northstar, in station construction revenues between periods, primarily due to the completion of nine new CNG stations for two refuse customers, two CNG station upgrades for one of our existing transit customers, one CNG station upgrade for one new transit customer, and one new CNG station for a trucking customer. Our acquisitions of IMW on September 7, 2010 and Northstar on December 15, 2010 contributed $43.2 million and $7.6 million, respectively, to our increased revenue between periods. Revenue attributable to VETC also increased between periods as we recorded $13.4 million of revenue related to fuel tax credits in the first nine months of 2011. We did not record any revenue related to fuel tax credits in the first nine months of 2010 as the fuel tax credits were not reinstated until the fourth quarter of 2010. These increases were offset by the decrease in our effective price per gallon that we charged to our customers between periods. Our effective price per gallon was $0.86 in the nine months ended September 30, 2011, which represents a $0.15 per gallon decrease from $1.01 in the nine months ended September 30, 2010. The decrease was primarily due to a higher percentage of O&M contracts in the first nine months of 2011, which generate less revenue per gallon than contracts where we supply the natural gas commodity. Revenue also decreased by $10.5 million between periods due to decreased sales of natural gas vehicle equipment by BAF.

Cost of sales. Cost of sales increased by $58.5 million to $150.2 million in the nine months ended September 30, 2011, from $91.7 million in the nine months ended September 30, 2010. Our cost of sales primarily increased between periods as a result of delivering more volume to our customers. Our acquisition of IMW on September 7, 2010 and Northstar on December 15, 2010 contributed $40.8 million and $5.0 million, respectively, to our increased cost of sales between periods. We also experienced a $13.5 million increase, excluding Northstar, in station construction costs between periods. These increases were offset by the decrease in our effective cost per gallon of $0.09 per gallon, to $0.62 per gallon, in the nine months ended September 30, 2011. This decrease was primarily the result of a higher percentage of O&M contracts in the first nine months of 2011 that are included in our volume totals but do not increase our cost of sales amount significantly as we do not pay for the natural gas consumed at the properties. We also experienced a $8.0 million of decrease in costs related to BAF's vehicle equipment sales between periods.

Derivative (gain) loss on Series I warrant valuation. Derivative gain decreased by $2.8 million to a $3.1 million gain in the nine months ended September 30, 2011, from $5.9 million in the nine months ended September 30, 2010. The amounts represent the non-cash impact attributable to valuing our outstanding Series I warrants based on the required mark-to-market accounting for the warrants (see note 18 to our condensed consolidated financial statements contained elsewhere herein) during the nine month periods ended September 30, 2010 and 2011.

Selling, general and administrative. Selling, general and administrative expenses increased by $15.4 million to $59.8 million in the nine months ended September 30, 2011, from $44.4 million in the nine months ended September 30, 2010. A significant portion of this increase was the result of our salaries and benefits expense increasing by $9.1 million between periods as we increased our employee headcount from 622 at September 30, 2010 to 937 at September 30, 2011. We also experienced a $5.0 million increase in occupancy costs, business insurance, employee recruiting, bank and credit card fees, information technology maintenance, training and seminars, and general office expenses related to our continued business growth and our acquisitions of IMW and Northstar during the third and fourth quarters of 2010. Our travel and entertainment expenses increased $1.2 million between periods, primarily due to the increased travel of our sales team. Stock option expense between periods increased $0.9 million, primarily due to the stock options issued in 2011 to new employees. During the first nine months of 2011, we incurred $0.8 million of costs related to developing new engine products for BAF. Our professional fees increased $0.7 million between periods, primarily for legal, audit and consulting services related to our continued business growth. In addition, our marketing expenses increased $0.3 million between periods due to certain advertising we conducted in the trucking, refuse and transit markets related to our continued business growth. Offsetting these increases was a decrease of $2.6 million during the first nine months of 2011 related to a decrease in the IMW and BAF contingent consideration liabilities.

Depreciation and amortization. Depreciation and amortization increased by $6.8 million to $22.4 million in the nine months ended September 30, 2011, from $15.6 million in the nine months ended September 30, 2010. This was primarily due to additional depreciation expense in the nine months ended September 30, 2011 related to increased property and equipment balances between periods, primarily related to our expanded station network. Our September 30, 2011 amortization expense also includes increased amortization of the intangible assets we obtained in connection with our acquisition of IMW in the third quarter of 2010 and Northstar in the fourth quarter of 2010.

Interest income (expense), net. Interest income (expense), net, increased by $5.5 million, from $0.0 for the nine months ended September 30, 2010, to $5.5 million of expense for the nine months ended September 30, 2011. This increase was primarily the result of an increase in interest expense in the nine months ended September 30, 2011 related to debt we incurred in connection with the acquisitions of IMW and Norhtstar, and interest expense related to the DCEMB's revenue bonds that closed March 31, 2011 (see note 12 to our condensed consolidated financial statements contained elsewhere herein). We also incurred increased interest expense between periods related to the $200.0 million of debt securities we issued in July and August of 2011.

Other income (expense), net. Other income (expense), net, increased by $1.4 million to $1.7 million of expense in the nine months ended September 30, 2011. This increase was primarily due to the impact of foreign currency exchange losses on the notes we issued as part of the IMW acquisition.

Income from equity method investments. During the nine months ended September 30, 2011, we recorded equity income of $0.5 million related to our 49% interest in our Peruvian joint venture, and for the nine months ended September 30, 2010, we recorded income of $0.2 million related to our interest.

Loss (income) of noncontrolling interest. There was no significant change in loss (income) of noncontrolling interest between the nine months ended September 30, 2011 and the nine months ended September 30, 2010. The noncontrolling interest represents the 30% interest in DCEMB held by our joint venture partner.

Seasonality and Inflation

To some extent, we experience seasonality in our results of operations. Natural gas vehicle fuel amounts consumed by some of our customers tends to be higher in summer months when buses and other fleet vehicles use more fuel to power their air conditioning systems. Natural gas commodity prices tend to be higher in the fall and winter months due to increased overall demand for natural gas for heating during these periods.

Since our inception, inflation has not significantly affected our operating results. However, costs for construction, repairs, maintenance, electricity and insurance are all subject to inflationary pressures and could affect our ability to maintain our stations adequately, build new stations, build new LNG plants, build new biomethane production facilities and expand our existing facilities or materially increase our operating costs.

Liquidity and Capital Resources

We require cash to fund our operating expenses and working capital requirements including outlays for the construction of new fueling stations, construction of LNG production facilities, the purchase of new LNG tanker trailers, investment in biomethane production, mergers and acquisitions, the financing of natural gas vehicles for our customers and general corporate purposes, including making deposits to support our derivative activities, geographic expansion (domestically and internationally), expanding our sales and marketing activities, support of legislative initiatives and for working capital for our expansion. Our principal sources of liquidity are cash on hand, cash provided by operating activities and cash provided by financing activities.

Liquidity

Cash provided by operating activities was $2.0 million for the nine months ended September 30, 2011, compared to $11.8 million for the nine months ended September 30, 2010. The decrease in operating cash flow resulted primarily from changes in working capital balances due to timing differences related to various cash flows between periods.

Cash used in investing activities was $125.2 million for the nine months ended September 30, 2011, compared to $57.1 million for the nine months ended September 30, 2010. Our purchases of property and equipment were $49.5 million during the first nine months of 2011, and $41.4 million during the first nine months of 2010. During the first nine months of 2010, we made a cash payment of $15.6 million related to our acquisition of IMW. We made additional investments in the Vehicle Production Group, LLC ("VPG"), a company developing a CNG taxi which is also a paratransit vehicle, during the first nine months of 2011 totaling $2.7 million, compared to $0.4 million for the same period in 2010. We also invested $1.2 million for a 19.9% interest in ServoTech Engineering, Inc. ("ServoTech"), a company that provides design and engineering services for natural gas fueling systems, among other services, during the nine months ended September 30, 2011. Also during the nine months ended September 30, 2011, as part of the DCEMB bond offering, we placed $23.9 million of cash into restricted accounts to be used for the capital expenditures of DCEMB and we designate $47 million as restricted cash to be used for constructing LNG fueling stations.

Cash provided by financing activities for the nine months ended September 30, 2011 was $227.5 million, compared to $10.3 million for the nine months ended September 30, 2010. This increase is primarily due to the $200.0 million we raised from debt securities that closed in July and August of 2011, and the DCEMB bond offering of $40.2 million for the expansion of the landfill gas processing facility owned by DCEMB that closed on March 31, 2011. Additionally, we received net proceeds from borrowings under our HSBC line of credit of $4.5 million to finance the working capital needs at IMW. These increases were offset by $9.9 million we paid on March 31, 2011 to pay off our Facility B Loan, and the cash payment of $5.0 million we made as part of the first IMW Note payment owed as part of the acquisition of IMW. During the first nine months of 2011, we made contingent payments on our IMW and BAF acquisitions of $2.4 million. Additionally we only received net proceeds of $1.2 million from the exercise of employee stock options in the nine months ended September 30, 2011, compared to $10.8 million of proceeds for the nine months ended September 30, 2010.

Our financial position and liquidity are, and will be, influenced by a variety of factors, including our ability to generate cash flows from operations, deposits and margin calls on our futures positions, the level of any outstanding indebtedness and the interest we are obligated to pay on this indebtedness, our capital expenditure requirements (which consist primarily of station construction, LNG plant construction costs, biomethane plant construction costs and the purchase of LNG tanker trailers and equipment) and any merger or acquisition activity.

Sources of Cash

Historically, our principal sources of cash have consisted of cash provided by operations and financing activities. At September 30, 2011, we had total cash and cash equivalents of $159.0 million, compared to $55.2 million at December 31, 2010.

On July 11, 2011, we entered into a loan agreement with Chesapeake NG Ventures Corporation ("Chesapeake"), an indirect wholly owned subsidiary of Chesapeake Energy Corporation, whereby Chesapeake agreed to purchase from us up to $150 million aggregate principal amount of debt securities for the development, construction and operation of liquefied natural gas stations pursuant to the issuance of three convertible promissory notes, each having a principal amount of $50 million (collectively the "Notes"). Chesapeake Energy Corporation guaranteed Chesapeake's commitment to purchase the Notes under the Loan Agreement. The first $50 million convertible promissory note closed on, July 11, 2011, and the second and third tranches are expected to close in June 2012 and June 2013, respectively.

On August 30, 2011, we issued $150 million aggregate principal amount of debt securities to three institutional investors.

Capital Expenditures

Our business plan calls for approximately $18.8 million in capital expenditures from October 1, 2011 through the end of 2011, primarily related to construction of new fueling stations and our biomethane project outside Detroit, Michigan. This amount excludes (i) the capital expenditures related to LNG fueling station construction to be funded by the proceeds of our July 2011 financing transaction with Chesapeake, and (ii) the capital expenditures DCEMB will make at its landfill gas processing facility with the proceeds it received on March 31, 2011 when it completed its bond offering. We may also elect to invest additional amounts in expansion of our California LNG plant or for other acquisitions or investments in companies or assets in the natural gas fueling infrastructure, services and production industries, including biomethane production. At September 30, 2011, we had cash and cash equivalents of $159.0 million, and we will need to raise additional capital as necessary to fund any of the aforementioned activities or other capital expenditures or investments that we cannot fund through available cash, the potential exercise of a warrant for 15,000,000 shares of our common stock at an exercise price of $10 per share held by Boone Pickens, or cash generated by operations. The timing and necessity of any future capital raise will depend primarily on our rate of new station construction, which may be affected by any federal legislation that provides incentives for natural gas vehicle purchases and fuel use, any decision to expand our California LNG plant or to invest in additional biomethane production facilities or other opportunities in the natural gas fueling industry and potential merger or acquisition activity. We may not be able to raise capital on terms that are favorable to existing stockholders or at all. Any inability to raise capital may impair our ability to invest in new stations, expand our California LNG plant, develop natural gas fueling infrastructure and invest in strategic transactions or acquisitions, expand biomethane production and reduce the ability of our business to grow and generate increased revenues.

Off-Balance Sheet Arrangements

At September 30, 2011, we had the following off-balance sheet arrangements that had, or are reasonably likely to have, a material effect on our financial condition:

- outstanding surety bonds for construction contracts and general corporate purposes totaling $80.3 million,
- two take-or-pay contracts for the purchase of LNG,
- operating leases where we are the lessee,
- operating leases where we are the lessor and owner of the equipment, and
- firm commitments to sell CNG and LNG at fixed prices.

We provide surety bonds primarily for construction contracts in the ordinary course of business as a form of guarantee. No liability has been recorded in connection with our surety bonds as we do not believe, based on historical experience and information currently available, that it is probable that any amounts will be required to be paid under these arrangements for which we will not be reimbursed.

We have entered into two contracts that require us to purchase minimum volumes of LNG. One contract expires in June 2014 and the other contract expires in October 2017.

We have entered into operating lease arrangements for certain equipment and for our office and field operating locations in the ordinary course of business. The terms of our leases expire at various dates through 2016. Additionally, in November 2006, we entered into a ground lease for 36 acres in California on which we built our California LNG liquefaction plant. The lease is for an initial term of thirty years and requires payments of $0.2 million per year, plus up to $0.1 million per year for each 30 million gallons of production capacity utilized, subject to future adjustment based on consumer price index changes. We must also pay a royalty to the landlord for each gallon of LNG produced at the facility, as well as a fee for certain other services that the landlord will provide.

We are also the lessor in various leases with our customers, whereby our customers lease certain stations and equipment that we own.

Item 3.—Quantitative and Qualitative Disclosures about Market Risk

In the ordinary course of business, we are exposed to various market risk factors, including changes in general economic conditions, domestic and foreign competition, commodity price risk and foreign currency exchange rates.

Commodity Risk. We are subject to market risk with respect to our sales of natural gas, which has historically been subject to volatile market conditions. Our exposure to market risk is heightened when we have a fixed price sales contract with a customer that is not covered by a futures contract, or when we are otherwise unable to pass natural gas price increases through to customers. Natural gas prices and availability are affected by many factors, including weather conditions, overall economic conditions and foreign and domestic governmental regulation and relations.

Natural gas costs represented 35% (or 47% excluding BAF, IMW and Northstar) of our cost of sales for 2010 and 24% (or 41% excluding BAF, IMW and Northstar) of our cost of sales for nine months ended September 30, 2011. Prices for natural gas over the eleven-year and nine month period from December 31, 1999 through September 30, 2011, based on the NYMEX daily futures data, have ranged from a low of $1.65 per Mcf to a high of $19.38 per Mcf. At September 30, 2011, the NYMEX index price of natural gas was $3.85 per Mcf.

To reduce price risk caused by market fluctuations in natural gas, we may enter into exchange traded natural gas futures contracts. These arrangements also expose us to the risk of financial loss in situations where the other party to the contract defaults on its contract or there is a change in the expected differential between the underlying price in the contract and the actual price of natural gas we pay at the delivery point.

We account for these futures contracts in accordance with FASB authoritative guidance on derivatives. The accounting under this guidance for changes in the fair value of a derivative depends upon whether it has been specified in a hedging relationship and, further, on the type of hedging relationship. To qualify for designation in a hedging relationship, specific criteria must be met and appropriate documentation maintained.

The fair value of the futures contracts we use is based on quoted prices in active exchange traded or over the counter markets which are then discounted to reflect the time value of money for contracts applicable to future periods. The fair value of these futures contracts is continually subject to change due to market conditions. In an effort to mitigate the volatility in our earnings related to futures activities, our board of directors adopted a revised natural gas hedging policy which restricts our ability to purchase natural gas futures contracts and offer fixed price sales contracts to our customers. We plan to structure prospective futures contracts so that they will be accounted for as cash flow hedges under this guidance, but we cannot be certain they will qualify. For more information, please read “Risk Management Activities” above.

We have prepared a sensitivity analysis to estimate our exposure to market risk with respect to the futures contracts we hold as of September 30, 2011 to hedge the fixed price component of certain supply contracts. If the price of natural gas were to fluctuate (increase or decrease) by 10% from the price quoted on NYMEX on September 30, 2011 ($3.85 per MMbtu), we could expect a corresponding fluctuation in the value of the contracts of approximately $0.4 million.

Foreign exchange rate risk. Because we have foreign operations, we are exposed to foreign currency exchange gains and losses. Since the functional currency of our foreign operations is in their local currency, the currency effects of translating the financial statements of those foreign subsidiaries, which operate in local currency environments, are included in the accumulated other comprehensive income (loss) component of consolidated equity and do not impact earnings. However, foreign currency transaction gains and losses not in our subsidiaries’ functional currency do impact earnings and resulted in approximately $1.4 million of losses in the nine months ended September 30, 2011. During the nine months ended September 30, 2011, our primary exposure to foreign currency rates related to our Canadian operations that had certain outstanding notes payable denominated in the U.S. dollar that were not hedged.

We have prepared a sensitivity analysis to estimate our exposure to market risk with respect to our monetary transactions denominated in a foreign currency. If the exchange rate on these assets and liabilities were to fluctuate by 10% from the rate as of September 30, 2011, we would expect a corresponding fluctuation in the value of the assets and liabilities of approximately $3.0 million.

Item 4.— Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. We carried out an evaluation, under the supervision of and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report.

Changes in Internal Control over Financial Reporting

We regularly review our system of internal control over financial reporting and make changes to our processes and systems to improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new, more efficient systems, consolidating activities, and migrating processes.

There were no changes in our internal control over financial reporting that occurred during the period covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II.—OTHER INFORMATION

Item 1.—Legal Proceedings

We are party to various legal actions that have arisen in the ordinary course of our business. During the course of our operations, we are also subject to audit by tax authorities for varying periods in various federal, state, local, and foreign tax jurisdictions. Disputes have and may continue to arise during the course of such audits as to facts and matters of law. It is impossible at this time to determine the ultimate liabilities that we may incur resulting from any lawsuits, claims and proceedings, audits, commitments, contingencies and related matters or the timing of these liabilities, if any. If these matters were to be ultimately resolved unfavorably, an outcome not currently anticipated, it is possible that such outcome could have a material adverse effect upon our consolidated financial position or results of operations. However, we believe that the ultimate resolution of such actions will not have a material adverse effect on our consolidated financial position, results of operations, or liquidity.

On July 15, 2010, the IRS sent us a letter (i) disallowing approximately $5.1 million related to certain claims we made from October 1, 2006 to June 30, 2008 under the Volumetric Excise Tax Credit program, and (ii) seeking repayment of such amount. We believe our claims were properly made and are contesting the IRS's determination.

Item 1A.—Risk Factors

An investment in our Company involves a high degree of risk of loss. You should carefully consider the risk factors discussed below and all of the other information included in this report before you decide to purchase shares of our common stock. We believe the risks and uncertainties described below are the most significant we face. The occurrence of any of the following risks could harm our business. In that case, the trading price of our common stock could decline. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our operations.

We have a history of losses and may incur additional losses in the future.

For the nine month period ended September 30, 2011, we incurred pre-tax losses of $29.5 million, which included derivative gains of $3.1 million related to marking to market the value of our Series I warrants. During the nine month period ended September 30, 2011, our loss was decreased by our receipt of approximately $13.4 million of revenue from federal fuel tax credits. In 2008, 2009 and 2010, we incurred pre-tax losses of $44.3 million, $33.4 million, and $4.2 million, respectively. Our loss for 2008 includes $18.6 million in expenses associated with our support for Proposition 10, the California Alternative Fuel Vehicles and Renewable Energy ballot initiative; our loss for 2009 includes $17.4 million of derivative losses related to marking to market the value of our Series I warrants; and our loss for 2010 was decreased by a derivative gain of $10.3 million on our Series I warrants. During 2008, 2009 and 2010, our losses were substantially decreased by our receipt of approximately $17.2 million, $15.5 million and $16.0 million of revenue from federal fuel tax credits, respectively. In order to execute our strategy and improve our financial performance, we must continue to invest in developing the natural gas vehicle fuel market and offer our customers compelling natural gas fuel prices. If we do not achieve or maintain profitability that can be sustained in the absence of federal fuel tax credits, our business will suffer and the price of our common stock may drop. In addition, if the price of our common stock increases during future periods when our Series I warrants are outstanding, we may be required to recognize material losses based on the valuation of the outstanding Series I warrants.

A material portion of our historical revenues are associated with a federal fuel excise tax credit that expires on December 31, 2011.

The federal excise tax credit of $0.50 per gasoline gallon equivalent of CNG and liquid gallon of LNG sold for vehicle fuel use, which began on October 1, 2006, expires December 31, 2011. Based on the service relationship we have with our customers, either we or our customers are able to claim the credit. For the nine month period ended September 30, 2011, we recorded approximately $13.4 million related to fuel tax credits, representing approximately 6.5% of our total revenue. In 2008, 2009 and 2010, we recorded approximately $17.2 million, $15.5 million and $16.0 million of revenue, respectively, related to fuel tax credits, representing approximately 13.7%, 11.8% and 7.6%, respectively, of our total revenue during the periods. On July 15, 2010, the IRS sent us a letter disallowing approximately $5.1 million related to certain excise tax credit claims that we made from October 1, 2006 to June 30, 2008. If we are unsuccessful in appealing the IRS disallowance of these claims, we may be required to refund some or all of the $5.1 million in contested claims.

We will need to raise debt or equity capital to continue to fund the growth of our business.

We will be required to raise debt or equity capital to fund the growth of our business. At September 30, 2011, we had total cash and cash equivalents of $159.0 million, and our business plan calls for approximately $18.8 million in capital expenditures from October 1, 2011 through the end of 2011. This amount excludes (i) the capital expenditures related to LNG fueling station construction to be funded by the proceeds of our July 2011 financing transaction with Chesapeake, and (ii) the capital expenditures DCEMB will make at its landfill gas processing facility with the proceeds it received on March 31, 2011 when it completed its bond offering. We may also require capital for unanticipated expenses, mergers and acquisitions and strategic investments. In addition, we have committed to significant future payments that we will be required to make in connection with our acquisitions of IMW and Northstar. At September 30, 2011, our future payments for IMW and Northstar totaled $37.5 million and $7.5 million, respectively. We are also obligated to pay up to $40.0 million as additional consideration related to our IMW acquisition if certain performance measurements of IMW are met and up to $11.0 million as additional consideration related to our BAF acquisition if certain performance measurements of BAF are met.

Equity or debt financing options may not be available on terms favorable to us or at all, particularly if there are no effective federal incentives supporting the growth of the natural gas fueling business. Additional sales of our common stock or securities convertible into our common stock will dilute existing stockholders and may result in a decline in our stock price. We may also pursue debt financing options including, but not limited to, equipment financing, the sale of convertible promissory notes or commercial bank financing. Recent economic turmoil and severe lack of liquidity in the debt capital markets and volatility in the equity capital markets have adversely affected capital raising opportunities. If we are unable to obtain debt or equity financing in amounts sufficient to fund any unanticipated expenses, capital expenditures, mergers, acquisitions or strategic investments, we will be forced to suspend or curtail these capital expenditures or postpone or delay potential acquisitions or other strategic transactions, which would harm our business, results of operations, and future prospects.

We are required to make substantial future payments to the holders of our debt securities.

During July and August, 2011, we issued $200.0 million of debt securities and agreed to issue an additional $50.0 million of debt securities in each of July 2012 and July 2013. Such debt securities bear interest at the rate of 7.5% per annum (payable quarterly, in arrears, on March 31, June 30, September 30 and December 31 of each year). The entire principal balance of the debt securities issued in July 2011 is due and payable in July 2018, and the entire principal balance of the debt securities we issued in August 2011 is due and payable in August 2016. We may repay the debt securities in common stock or cash. We expect our interest payment obligations under the debt securities to be approximately $3.8 million and $16.9 million for the period October 1, 2011 through December 31, 2011 and for the year ending December 31, 2012, respectively. These interest payment amounts include the interest that will be due on an additional $50 million of debt securities we anticipate issuing in June, 2012. In future periods, we may not have sufficient capital resources to enable us to fulfill our payment obligations to the holders of our debt securities. If we are unable to make scheduled payments or comply with the other provisions of the documents relating to the debt securities, the holders of such securities may be permitted under certain circumstances to accelerate the maturity of the securities and exercise other remedies provided for in the securities and under applicable law. An acceleration of the maturity of the debt securities that is not rescinded would have a material adverse effect on our company.

Our growth is influenced by tax and related government incentives for clean burning fuels and alternative fuel vehicles. A reduction in these incentives or the failure to pass new legislation with new incentive programs will increase the cost of natural gas fuel and vehicles for our customers and may reduce our revenue.

Our business is influenced by tax credits, rebates and similar federal, state and local government incentives that promote the use of natural gas as a vehicle fuel in the United States. The federal income tax credit that was available to offset 50% to 80% of the incremental cost of purchasing new or converted natural gas vehicles expired on December 31, 2010. The absence of these vehicle tax credits could have a detrimental effect on the natural gas vehicle and fueling industry, including sales at our wholly owned subsidiary, BAF, and adversely affect our results of operations and financial performance. Our business plan and the ability of our business to successfully grow depends in part on the extension of the federal fuel excise tax credit for natural gas vehicle fuel, the reinstatement and extension of the federal income tax credit for the purchase of natural gas vehicles and the passage of legislation providing for additional incentives for the sale and use of natural gas vehicles. If existing federal incentives are not reinstated or extended and if new incentives are not passed, fewer natural gas vehicles will be sold and used and our revenue and financial performance will be adversely affected. Furthermore, the failure of certain federal, state or local government incentives which promote the use of natural gas as a vehicle fuel to pass into law could result in a negative perception by the market generally and a decline in the market price of our common stock. In addition, if grant funds are no longer available under existing government programs for the purchase and construction of natural gas vehicles and stations, the purchase of natural gas vehicles and station construction could slow and our business and results of operations will be adversely affected. Continued reduction in tax revenues associated with high unemployment rates, economic recession or slow-down could result in a significant reduction in funds available for government grants that support vehicle conversion and station construction, which could impair our ability to grow our business.

Challenges we may encounter managing our growth may divert resources and limit our ability to successfully expand our operations.

We have been and continue to be engaged in a period of rapid and substantial growth, which places a strain on our operational infrastructure and imposes significant added responsibilities on members of our management. Our ability to manage our operations and growth effectively requires us to continue to hire, train and integrate necessary personnel to further develop our operational, financial and management controls, expand and improve our financial reporting and legal compliance systems and manage our natural gas station construction, maintenance and operations projects. If we are not able to effectively manage our business growth in a cost-effective manner, our operating results, sales and revenues may be negatively impacted.

Automobile and engine manufacturers currently produce very few originally manufactured natural gas vehicles and engines for the United States and Canadian markets, which may restrict our sales.

Limited availability of natural gas vehicles and engine sizes for heavy duty vehicles restricts their wide scale introduction and narrows our potential customer base. Original equipment manufacturers produce a small number of natural gas engines and vehicles, and they may not make adequate investments to expand their natural gas engine and vehicle product lines. For the North American market, there is only one major automobile manufacturer that currently makes natural gas powered passenger vehicles, and major manufacturers of medium and heavy duty vehicles currently produce only a narrow range and number of natural gas vehicles. The technology utilized in some of the heavy duty vehicles that run on LNG is also relatively new and has not been previously deployed or used in large numbers of vehicles. As a result, these vehicles may require servicing and further technology refinements to address performance issues that may occur as vehicles are deployed in large numbers and are operated under strenuous conditions. If potential heavy duty LNG truck purchasers are not satisfied with truck performance, additional heavy-duty truck engine manufacturers do not enter the market for LNG engines, or LNG engines are not otherwise developed, produced and adopted in greater numbers, our LNG fueling business may be delayed, impaired, or eliminated, which would adversely affect our financial performance. Further, North American car and truck manufacturers are facing significant economic challenges that may make it difficult or impossible for them to introduce new natural gas vehicles in the North American market or continue to manufacture and support the limited number of available natural gas vehicles. Due to the limited supply of natural gas vehicles, our ability to promote natural gas vehicles and our natural gas fuel sales may be restricted, even if there is demand.

We May Not be Successful in Executing our LNG Fueling Station Strategy.

Our current business plan calls for us to develop LNG truck fueling stations at strategic truck stop locations along major trucking corridors in the United States. Failure to execute this strategy may adversely affect our financial results and business. Our strategy to develop LNG fueling stations may not be successful for many reasons, including:

- We may have difficulty identifying and obtaining sufficient rights to use suitable locations for LNG fueling stations;
- We may have insufficient resources to develop planned stations;
- We may experience delays in building stations, including delays in obtaining necessary permits and approvals;
- Heavy duty natural gas engines may not be adopted at all or may be adopted at a rate that is slower than our expectations due to, among other things, failure by manufacturers to develop and produce such engines, performance issues relating to such engines and the cost of such engines;
- We may have difficulty sourcing and transporting sufficient LNG; and
- LNG may not be an attractive alternative to diesel fuel in the future.

Decreases in the price of gasoline and diesel fuel may slow the growth of our business and negatively impact our financial results.

Recent increases in prices for gasoline and diesel fuel have resulted in increased interest in alternative fuels such as CNG and LNG. However, any decline in the price of diesel fuel and gasoline may result in reduced interest in CNG and LNG, which would slow the growth of our business. In addition, to the extent that we price our CNG and LNG fuel at a discount to these reduced diesel or gasoline prices in an effort to attract new and retain existing customers, our profit margin on fuel sales may be harmed and our financial results negatively impacted. Further, lower fuel prices for CNG and LNG as a result of lower natural gas commodity prices also will reduce our revenues.

If the prices of CNG and LNG do not remain sufficiently below the prices of gasoline and diesel, potential fleet customers will have less incentive to purchase natural gas vehicles, which would decrease demand for CNG and LNG and limit our growth.

Natural gas vehicles cost more than comparable gasoline or diesel powered vehicles because converting a vehicle to use natural gas adds to its base cost. If the prices of CNG and LNG do not remain sufficiently below the prices of gasoline or diesel, fleet operators may be unable to recover the additional costs of acquiring or converting to natural gas vehicles in a timely manner, and they may choose not to use natural gas vehicles. Our ability to offer CNG and LNG fuel to our customers at lower prices than gasoline and diesel depends in part on natural gas prices remaining lower, on an energy equivalent basis, than oil prices. If the price of oil declines and the price of natural gas increases, it will make it more difficult for us to offer our customers discounted prices for CNG and LNG as compared to gasoline and diesel prices and maintain an acceptable margin on our sales. Recent and significant volatility in oil and gasoline prices demonstrate that it is difficult to predict future transportation fuel costs. In addition, any new regulations imposed on natural gas extraction in the United States, particularly on extraction of natural gas from shale formations, could increase the costs of domestic gas production or make it more costly to produce natural gas in the United States, which could lead to substantial increases in the price of natural gas. Reduced prices for gasoline and diesel fuel, combined with higher costs for natural gas and natural gas vehicles, may cause potential customers to delay or reject converting their fleets to run on natural gas. In that event, our sales of natural gas fuel and vehicles would be slowed and our business would suffer.

The volatility of natural gas prices could adversely impact the adoption of CNG and LNG vehicle fuel and our business.

In the recent past, the price of natural gas has been volatile, and this volatility may continue. From the end of 1999 through December 31, 2010, the price for natural gas, based on the NYMEX daily futures data, ranged from a low of $1.65 per Mcf to a high of $19.38 per Mcf. At September 30, 2011, the NYMEX index price for natural gas was $3.85 per Mcf. Increased natural gas prices affect the cost to us of natural gas and will adversely impact our operating margins in cases where we have committed to sell natural gas at a fixed price without an effective futures contract in place that fully mitigates the price risk or where we otherwise cannot pass the increased costs on to our customers. In addition, higher natural gas prices may cause CNG and LNG to cost as much as or more than gasoline and diesel generally, which would adversely impact the adoption of CNG and LNG as a vehicle fuel and our business. Conversely, lower natural gas prices reduce our revenues due to the fact that in a significant amount of our customer agreements, the commodity cost is passed through to the customer. Among the factors that can cause price fluctuations in natural gas prices are changes in domestic and foreign supplies of natural gas, domestic storage levels, crude oil prices, the price difference between crude oil and natural gas, price and availability of alternative fuels, weather conditions, negative publicity surrounding drilling techniques, level of consumer demand, economic conditions, price of foreign natural gas imports, and domestic and foreign governmental regulations and political conditions. In particular, there have been recent legislative efforts to place new regulatory requirements on the production of natural gas by hydraulic fracturing of shale gas reservoirs. Hydraulic fracturing of shale gas reservoirs has resulted in a substantial increase in the proven natural gas reserves in the United States, and any changes in regulations that make it more expensive or unprofitable to produce natural gas through hydraulic fracturing could lead to increased natural gas prices. The recent economic recession and increased domestic natural gas supplies have contributed to significant declines in the price of natural gas since the summer of 2008.

Our growth depends in part on environmental regulations and programs mandating the use of cleaner burning fuels, and modification or repeal of these regulations may adversely impact our business.

Our business depends in part on environmental regulations and programs in the United States that promote or mandate the use of cleaner burning fuels, including natural gas for vehicles. Industry participants with a vested interest in gasoline and diesel, many of which have substantially greater resources than we do, invest significant time and money in an effort to influence environmental regulations in ways that delay or repeal requirements for cleaner vehicle emissions. Further, economic difficulties may result in the delay, amendment or waiver of environmental regulations due to the perception that they impose increased costs on the transportation industry that cannot be absorbed in a contracting economy. For example, the Clean Trucks Program at the Ports of Los Angeles and Long Beach formerly called for the replacement of a set number of drayage trucks with “clean” trucks, but due to economic conditions and other factors, the Clean Trucks Program no longer calls for any specific number of “clean” truck replacements. In addition, many of the “clean” trucks that have been deployed have been “clean diesel” trucks which are generally less expensive than LNG trucks. There have also been recent ballot initiatives in the State of California and lawsuits aimed at postponing or delaying California’s implementation of AB 32, also known as the Global Warming Solutions Act of 2006, which is intended to reduce greenhouse gas emissions. CNG, LNG and biomethane vehicle fuel all produce lower greenhouse gas emissions than gasoline or diesel fuel and the delay or repeal of AB 32, and in particular California’s low-carbon fuel standard, could reduce the appeal of natural gas fuel for our customers and reduce our revenue. The delay, repeal or modification of federal or state regulations or programs that encourage the use of cleaner vehicles could also have a detrimental effect on the United States natural gas vehicle industry, which, in turn, could slow our growth and adversely affect our business.

The use of natural gas as a vehicle fuel may not become sufficiently accepted for us to expand our business.

To expand our business, we must develop new customers and obtain and fulfill CNG and LNG fueling contracts from these customers. We cannot guarantee that we will be able to develop these customers or obtain these fueling contracts. Whether we will be able to expand our customer base will depend on a number of factors, including the level of acceptance and availability of natural gas vehicles, the growth in our target markets of fueling station infrastructure that supports CNG and LNG sales, our ability to supply

CNG and LNG at competitive prices and acceptance of our technology, fuel systems or services. A decline in oil, diesel fuel and gasoline prices may result in decreased interest in alternative fuels like CNG and LNG. In addition, there is reduced availability of debt financing as compared to prior years to support the purchase of CNG and LNG vehicles and investment in CNG and LNG infrastructure. If our potential customers are unable to access credit to purchase natural gas vehicles, it may make it difficult or impossible for them to invest in natural gas vehicle fleets, which would impair the ability of our business to grow. Further, potential customers may not find our technology, fuel systems or services acceptable.

Our global operations expose us to additional risk and uncertainties.

We have operations in a number of countries, including the United States, Canada, China, Colombia, Bangladesh and Peru. In addition to the other risks described herein, our global operations may be subject to risks and uncertainties that may limit our ability to operate our business. Our natural gas compression equipment is primarily manufactured in Canada and sold globally, which exposes us to a number of risks that can arise from international trade transactions, local business practices and cultural considerations, including:

- political unrest, terrorism and economic or financial instability;
- unexpected changes in regulatory requirements and uncertainty related to developing legal and regulatory systems governing economic and business activities, real property ownership and application of contract rights;
- import-export regulations;
- difficulties in enforcing agreements and collecting receivables;
- difficulties in ensuring compliance with the laws and regulations of multiple jurisdictions;
- difficulties in ensuring that health, safety, environmental and other working conditions are properly implemented and/or maintained by the local office;
- changes in labor practices, including wage inflation, labor unrest and unionization policies;
- limited intellectual property protection;
- local competitors misappropriating our product designs;
- longer payment cycles by international customers;
- currency exchange fluctuations;
- inadequate local infrastructure and disruptions of service from utilities or telecommunications providers, including electricity shortages;
- potentially adverse tax consequences; and
- differing employment practices and labor issues.

We also face risks associated with currency exchange and convertibility, inflation and repatriation of earnings as a result of our foreign operations. In some countries, economic, monetary and regulatory factors could affect our ability to convert funds to U.S. dollars or move funds from accounts in these countries. We are also vulnerable to appreciation or depreciation of foreign currencies against the U.S. dollar. We do not currently engage in currency hedging activities to limit the risks of currency fluctuations.

We may not be successful in managing or integrating IMW into our business, which could prevent us from realizing the expected benefits of the acquisition and could adversely affect our future results.

The integration of IMW into our business presents significant challenges and risks to our business, including (i) the distraction of management from other business concerns, (ii) the retention of customers of IMW, (iii) expansion into foreign markets, (iv) the introduction of IMW's compressor and related equipment manufacturing and servicing business, which is a new product line for us, (v) achievement of appropriate internal controls over financial reporting and (vi) the monitoring of compliance with all laws and regulations. The vast majority of IMW's revenue is derived from sales in emerging markets, and IMW has not previously been required to comply with the U.S. Foreign Corruption Practices Act or any of the requirements of Sarbanes-Oxley. If we do not successfully integrate IMW into our business and maintain regulatory compliance, we may not realize the benefits expected from the acquisition and our results of operations could be materially adversely affected. If the revenue of IMW declines or grows more slowly than we anticipate, or if its operating expenses are higher than we expect, we may not be able to achieve, sustain or increase the growth of our business, in which case our financial condition will suffer and our stock price could decline. In addition, the operations of IMW do not have the disclosure controls and procedures or internal controls over financial reporting that are as thorough or effective as those required for a public company. Although we intend to implement appropriate controls and procedures as we integrate the operations of IMW, we cannot provide assurance as to the effectiveness of the disclosure controls and procedures or internal controls over financial reporting of IMW until we have fully integrated them.

A significant portion of the purchase price of IMW was allocated to goodwill and a write-off of all or part of this goodwill could adversely affect our operating results.

Under business combination accounting standards, we allocated the total purchase price of IMW to its net tangible assets and liabilities and intangible assets based on their fair values as of the date of the acquisition and recorded the excess of the purchase price over those values as goodwill. Our estimates of the fair value of the assets and liabilities of IMW were based upon certain assumptions, including assumptions about and anticipated attainment of new business, believed to be reasonable, but which are inherently uncertain. Pursuant to the applicable accounting standards, we allocated $45.3 million of the purchase price for IMW to goodwill. Our goodwill could be impaired if developments affecting the acquired compressor manufacturing operations or the markets in which IMW produces and/or sells compressors lead us to conclude that the cash flows we expect to derive from its manufacturing operations will be substantially reduced. An impairment of all or part of our goodwill could adversely affect our results of operations and financial condition.

We may not be successful in managing or integrating our recently acquired subsidiary, Northstar, with our existing operations.

On December 15, 2010 we acquired Northstar, a leading provider of design, engineering, construction and maintenance services for LNG and LCNG fueling stations. Our ability to realize benefits from the acquisition depends on the growth of the LNG fueling market and our ability to successfully integrate Northstar's business with our existing operations. We cannot provide any assurances that the LNG fueling market, or Northstar's business, will grow or that we will successfully manage the integration of Northstar's business with our existing operations. In addition, the Northstar operations do not have the disclosure controls and procedures or internal controls over financial reporting that are as thorough or effective as those required for public companies. Although we intend to implement appropriate controls and procedures as we integrate the Northstar operations, we cannot provide assurance as to the effectiveness of Northstar's disclosure controls and procedures or internal controls over financial reporting until we have fully integrated them.

DCEMB's failure to comply with the terms of its bond financing agreements would impair our rights in DCEMB.

In connection with the issuance of the Revenue Bonds, DCEMB entered into, among other documents, the Loan Agreement, the Note, the Deed of Trust and the Security Agreement (collectively the "Bond Agreements"). Pursuant to the Bond Agreements, DCEMB is subject to certain covenants, including a requirement to make loan repayments on the Revenue Bonds. This repayment obligation is secured by a security interest in all of the Collateral (as defined in the Security Agreement), which includes, but is not limited to, DCEMB's rights, title and interest in any gas sale agreements and the funds and accounts held under an indenture. If DCEMB defaults on its obligation to make loan repayments on the Revenue Bonds, the Issuer or the Trustee may, among other things, take whatever action at law or in equity as may be necessary or desirable to ensure loan repayments are made on the Revenue Bonds. If the Issuer or the Trustee take any such actions, or if DCEMB otherwise fails to comply with its covenants and other obligations under the Bond Agreements, our rights in DCEMB would be impaired, and our business and results of operations may be adversely affected.

The infrastructure to support gasoline and diesel consumption is vastly more developed than the infrastructure for natural gas vehicle fuels.

Gasoline and diesel fueling stations and service infrastructure are widely available in the United States. For natural gas vehicle fuels to achieve more widespread use in the United States and Canada, they will require a promotional and educational effort and the development and supply of more natural gas vehicles and fueling stations. This will require significant continued effort by us, as well as government and clean air groups, and we may face resistance from oil companies and other vehicle fuel companies. A prolonged economic recession or disruption in the capital markets may make it difficult or impossible to obtain necessary financing to expand the natural gas vehicle fueling infrastructure and impair our ability to grow our business. There is no assurance natural gas will ever achieve the level of acceptance as a vehicle fuel necessary for us to expand our business significantly.

We have significant contracts with federal, state and local government entities that are subject to unique risks.

We have existing, and will continue to seek, long-term CNG and LNG station construction, maintenance and fuel sales contracts with various federal, state and local governmental bodies, which accounted for approximately 68% of our annual revenues in 2006 and approximately 41% of our annual revenues in 2010. In May and June 2009, we spent $5.6 million to acquire four new CNG operation and maintenance contracts with government agencies. In addition to our normal business risks, our contracts with these government entities are often subject to unique risks, some of which are beyond our control. Long-term government contracts and related orders are subject to cancellation if appropriations for subsequent performance periods are not made. The termination of funding for a government program supporting any of our CNG or LNG operations could result in a loss of anticipated future revenues attributable to that program, which could have a negative impact on our operations. In addition, government entities with whom we contract are often able to modify, curtail or terminate contracts with us without prior notice at their convenience, and are only liable for payment for work done and commitments made at the time of termination. Modification, curtailment or termination of significant contracts could have a material adverse effect on our results of operations and financial condition. In particular, if any of the contracts we recently acquired are terminated, we may be unable to recover our investment in acquiring the contracts. During the fourth quarter of 2010, we lost one of the acquired contracts in a competitive procurement, which resulted in a charge of $1.5 million related to the impairment of an intangible asset originally recorded with the acquisition.

Further, government contracts are frequently awarded only after competitive bidding processes, which have been and may continue to be protracted. For example, the Metropolitan Transit System of San Diego, which represented approximately 6.0 million of the gallons of CNG we sold in 2009, conducted a competitive bidding procurement and awarded the contract to a competitor on July 27, 2010. The Washington Metropolitan Area Transit Authority, which represented approximately 6.3 million of the gallons of CNG we sold in 2010, also conducted a competitive bidding procurement which resulted in the award of that contract to a competitor on December 31, 2010. In many cases, unsuccessful bidders for government agency contracts are provided the opportunity to formally protest certain contract awards through various agencies, administrative and judicial channels. The protest process may substantially delay a successful bidder’s contract performance, result in cancellation of the contract award entirely and distract management. We may not be awarded contracts for which we bid, and substantial delays or cancellation of purchases may even follow our successful bids as a result of such protests.

The budget deficits being experienced by many governmental entities may reduce the available funding for certain natural gas programs and services and the purchase of CNG or LNG fuel, which could reduce our revenue and impair our financial performance.

Many governmental entities are experiencing significant budget deficits as a result of the economic recession, which has and may continue to reduce or curtail their ability to fund natural gas fuel programs, purchase natural gas vehicles or provide public transportation and services, which would harm our business. Furthermore, in response to budget deficits, such governmental entities have and may continue to request or demand that we lower our price for CNG or LNG fuel.

Conversion of vehicles to run on natural gas is time-consuming and expensive and may limit the growth of our sales.

Conversion of vehicle engines from gasoline or diesel to natural gas is performed by only a small number of vehicle conversion suppliers (including our wholly owned subsidiary, BAF) that must meet stringent safety and engine emissions certification standards. The engine certification process is time consuming and expensive and raises vehicle costs. In addition, conversion of vehicle engines from gasoline or diesel to natural gas may result in vehicle performance issues or increased maintenance costs that could discourage our potential customers from purchasing converted vehicles that run on natural gas and impair the financial performance of BAF. Without an increase in vehicle conversion options, reduced vehicle conversion costs and improved vehicle conversion performance, our sales of natural gas vehicle fuel and converted natural gas vehicles, through BAF, may be restricted and our revenue will be reduced both by less demand for natural gas vehicle fuel and less demand for converted natural gas vehicles.

A majority of BAF’s sales of CNG vehicles are to one customer. If this customer does not continue to purchase CNG vehicles, then revenue at our wholly owned subsidiary, BAF, will decline and our financial results will be impaired.

During 2009 and 2010, BAF derived approximately 63% and 66%, respectively, of its revenue from AT&T. AT&T is not required to purchase any CNG vehicle conversion kits under its agreement with BAF and the agreement and all purchase orders submitted by AT&T under the agreement may be cancelled by AT&T at any time for any reason. If AT&T does not continue to order and pay for CNG vehicle conversion kits produced by BAF, then BAF’s sales revenue will substantially decline and our financial performance may suffer. AT&T has ordered fewer vehicles in the first nine months of 2011 compared to the first nine months of 2010. In the absence of continued sales to AT&T, BAF will experience materially reduced revenues and may require additional cash to continue its operations, which could drain our capital resources.

If there are advances in other alternative vehicle fuels or technologies, or if there are improvements in gasoline, diesel or hybrid engines, demand for natural gas vehicles may decline and our business may suffer.

Technological advances in the production, delivery and use of alternative fuels that are, or are perceived to be, cleaner, more cost-effective or more readily available than CNG or LNG have the potential to slow adoption of natural gas vehicles. Advances in gasoline and diesel engine technology, especially hybrids, may offer a cleaner, more cost-effective option and make fleet customers less likely to convert their fleets to natural gas. Technological advances related to ethanol or biodiesel, which are increasingly used as an additive to, or substitute for, gasoline and diesel fuel, may slow the need to diversify fuels and affect the growth of the natural gas vehicle market. In addition, a prototype heavy duty electric truck model was recently introduced at the ports of Los Angeles and Long Beach. Use of electric heavy duty trucks or the perception that electric heavy duty trucks may soon be widely available and provide satisfactory performance in heavy duty applications may reduce demand for heavy duty LNG trucks. In addition, hydrogen and other alternative fuels in experimental or developmental stages may eventually offer a cleaner, more cost-effective alternative to gasoline and diesel than natural gas. Advances in technology that slow the growth of or conversion to natural gas vehicles, or which otherwise reduce demand for natural gas as a vehicle fuel, will have an adverse effect on our business. Failure of natural gas vehicle technology to advance at a sufficient pace may also limit its adoption and our ability to compete with other alternative fuels and alternative fuel vehicles.

Our ability to supply LNG to new and existing customers is restricted by limited production of LNG and by our ability to acquire LNG without interruption and near our target markets.

Production of LNG in the United States is fragmented. LNG is produced at a variety of smaller natural gas plants around the United States, as well as at larger plants. It may become difficult for us to obtain additional LNG without interruption and near our current or target markets at competitive prices. If our LNG liquefaction plants, or any of those from which we purchase LNG, are damaged by severe weather, earthquake or other natural disaster, or otherwise experience prolonged downtime, our LNG supply will be restricted. Currently, one of the suppliers from whom we obtain LNG has experienced unscheduled plant shut downs and has been unable to maintain minimum production levels on a consistent basis, which has caused us to incur additional costs to obtain LNG from other sources. If we are unable to supply enough of our own LNG or purchase it from third parties to meet existing customer demand, we may be liable to our customers for penalties. Our growth plans, if successful, will require substantial growth in the available LNG supply across the United States, and if this supply is unavailable, it will constrain our ability to increase the market for LNG fuel including supplying LNG fuel to heavy duty truck customers. If we experience an LNG supply interruption or LNG demand that exceeds available supply, or if we have difficulty entering or maintaining relationships with contract carriers, our ability to expand LNG sales to new customers will be limited, our relationships with existing customers may be disrupted, and our results of operations may be adversely affected. Furthermore, because transportation of LNG is relatively expensive, if we are required to supply LNG to our customers from distant locations and cannot pass these costs through to our customers, our operating margins will decrease on those sales due to our increased transportation costs.

LNG supply purchase commitments may exceed demand causing our costs to increase and impacting our LNG sales margins.

Two of our LNG supply agreements have a take-or-pay commitment and our California LNG liquefaction plant has a land lease and other fixed operating costs regardless of production and sales levels. The take-or-pay commitments require us to pay for the LNG that we have agreed to purchase irrespective of whether we can sell the LNG to our own customers. For example, the LNG Sales Agreement that we entered into with Desert Gas Services ("DGS") on October 17, 2007 has a ten year term and, provided that Plant Capacity (as defined in the LNG Sales Agreement) is available to be taken by us, the plant is not shut down by DGS and no event beyond our reasonable control prevents us from taking delivery of LNG, we are committed to purchasing at least 45,000 gallons of LNG per day. Should the market demand for LNG decline, or if we lose significant LNG customers or if demand under any existing or any future LNG supply contract does not maintain its volume levels or grow, overall operating and supply costs may increase as a percentage of revenue and negatively impact our margins.

If we are unable to obtain natural gas in the amounts needed on a timely basis or at reasonable prices, we could experience an interruption of CNG or LNG deliveries or increases in CNG or LNG costs, either of which could have an adverse effect on our business.

Some regions of the United States and Canada depend heavily on natural gas supplies coming from particular fields or pipelines. Interruptions in field production or in pipeline capacity could reduce the availability of natural gas or possibly create a supply imbalance that increases natural gas prices. We have in the past experienced LNG supply disruptions due to severe weather in the Gulf of Mexico and plant outages. If there are interruptions in field production, insufficient pipeline capacity, equipment failure on liquefaction production or delivery delays, we may experience supply stoppages which could result in our inability to fulfill delivery commitments. This could result in our being liable for contractual damages and daily penalties or otherwise adversely affect our business.

Oil companies, station owners, industrial gas companies, and natural gas utilities, which have far greater resources and brand awareness than we have, may expand into the natural gas fuel market, which could harm our business and prospects.

There are numerous potential competitors who could enter the market for CNG and LNG vehicle fuels. Many of these potential entrants, such as integrated oil companies, industrial gas companies, and natural gas utilities, have far greater resources and brand awareness than we have. Natural gas utilities, particularly in California, continue to own and operate natural gas fueling stations that compete with our stations. Utilities in Michigan, Illinois, New Jersey, North Carolina and Georgia have also recently made efforts to invest in the natural gas vehicle fuel space. If the use of natural gas vehicles and demand for natural gas vehicle fuel increases, these companies may find it more attractive to enter or expand their operations in the market for natural gas vehicle fuels and we may experience increased pricing pressure, reduced operating margins and fewer expansion opportunities.

If we do not have effective futures contracts in place, increases in natural gas prices may cause us to lose money.

From 2005 to 2008, we sold and delivered approximately 30% of our total gasoline gallon equivalents of CNG and LNG under contracts that provided a fixed price or a price cap to our customers over terms typically ranging from one to three years, and in some cases up to five years. Effective January 1, 2007, we no longer offer contracts with a price cap to our customers, though, from time to time we still enter into contracts with various customers to sell CNG or LNG at fixed prices. At any given time, the market price of natural gas may rise and our obligations to sell fuel under fixed price contracts may be at prices lower than our fuel purchase price if we do not have effective futures contracts in place. This circumstance has in the past and may again in the future compel us to sell fuel at a loss, which would adversely affect our results of operations and financial condition. Commencing with the adoption of our revised natural gas hedging policy in February 2007, our policy has been to purchase futures contracts to hedge our exposure to natural gas price variability related to our fixed price contracts. Such contracts, however, may not be available or we may not have sufficient financial resources to secure such contracts. In addition, under our hedging policy, we may reduce or remove futures contracts we have in place related to these contracts if such disposition is approved in advance by our board of directors and derivative committee. If we are not effectively economically hedged with respect to our fixed price contracts, we will lose money in connection with those contracts during periods in which natural gas prices increase above the prices of natural gas included in our customers’ contracts. As of September 30, 2011, we were economically hedged with respect to our fixed price contracts with our customers.

Our futures contracts may not be as effective as we intend.

Our purchase of futures contracts can result in substantial losses under various circumstances, including if we do not accurately estimate the volume requirements under our fixed price customer contracts when determining the volumes included in the futures contracts we purchase, or we elect to purchase a futures contract in connection with a bid proposal and ultimately we are not awarded the entire contract or our customer does not fully perform its obligations under the awarded contract. We also could incur significant losses if a counterparty does not perform its obligations under the applicable futures arrangement, the futures arrangement is economically imperfect or ineffective, or our futures policies and procedures are not properly followed or do not work as planned. Furthermore, we cannot be assured that the steps we take to monitor our futures activities will detect and prevent violations of our risk management policies and procedures.

A decline in the value of our futures contracts may result in margin calls that would adversely impact our liquidity.

We are required to maintain a margin account to cover losses related to our natural gas futures contracts. Futures contracts are valued daily, and if our contracts are in loss positions at the end of a trading day, our broker will transfer the amount of the losses from our margin account to a clearinghouse. If at any time the funds in our margin account drop below a specified maintenance level, our broker will issue a margin call that requires us to restore the balance. Payments we make to satisfy margin calls will reduce our cash reserves, adversely impact our liquidity and may also adversely impact our ability to expand our business. Moreover, if we are unable to satisfy the margin calls related to our futures contracts, our broker may sell these contracts to restore the margin requirement at a substantial loss to us. As of September 30, 2011, we had $3.6 million on deposit related to our futures contracts.

If our futures contracts do not qualify for hedge accounting, our net income (loss) and stockholders’ equity will fluctuate more significantly from quarter to quarter based on fluctuations in the market value of our futures contracts.

We account for our futures activities under the relevant derivative accounting guidance, which requires us to value our futures contracts at fair market value in our financial statements. Prior to June 2008, our futures contracts did not qualify for hedge accounting, and therefore we have recorded any changes in the fair market value of these contracts directly in our consolidated statements of operations in the line item “derivative (gains) losses” along with any realized gains or losses during the period. Currently, we attempt to qualify all of our futures contracts for hedge accounting under the relevant derivative accounting guidance, but there can be no assurances that we will be successful in doing so. At September 30, 2011, all of our futures contracts qualified for hedge accounting. To the extent that all or some of our futures contracts do not qualify for hedge accounting, we could incur significant increases and decreases in our net income (loss) and stockholders’ equity in the future based on fluctuations in the market value of our futures contracts from quarter to quarter. We had no derivative gains or losses related to our natural gas futures contracts for the year ended December 31, 2010 and for the nine months ended September 30, 2011. Any negative fluctuations may cause our stock price to decline due to our failure to meet or exceed the expectations of securities analysts or investors.

Compliance with potential greenhouse gas regulations affecting our LNG plants or fueling stations may prove costly and negatively affect our financial performance.

California has adopted legislation, AB 32, which calls for a cap on greenhouse gas emissions throughout California and a statewide reduction to 1990 levels by 2020, and an additional 80% reduction below 1990 levels by 2050. Seven western U.S. states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces (British Columbia, Manitoba, Ontario and Quebec) formed the Western Climate Initiative to help combat climate change. Other states and the federal government are considering passing measures to regulate and reduce greenhouse gas emissions. Any of these regulations, when and if implemented, may regulate the greenhouse gas emissions produced by our LNG production plants in California and Texas or our CNG and LNG fueling stations and require that we obtain emissions credits or invest in costly emissions prevention technology. We cannot currently estimate the potential costs associated with federal or state regulation of greenhouse gas emissions from our LNG plants or CNG and LNG stations, and these unknown costs are not contemplated in the financial terms of our customer agreements. These unanticipated costs may have a negative impact on our financial performance and may impair our ability to fulfill customer contracts at an operating profit.

Natural gas fueling operations and vehicle conversions entail inherent safety and environmental risks that may result in substantial liability to us.

Natural gas fueling operations and vehicle conversions entail inherent risks, including equipment defects, malfunctions and failures and natural disasters, which could result in uncontrollable flows of natural gas, fires, explosions and other damages. For example, operation of LNG pumps requires special training and protective equipment because of the extreme low temperatures of LNG. LNG tanker trailers have also in the past been, and may in the future be, involved in accidents that result in explosions, fires and other damage. Improper refueling of LNG vehicles can result in venting of methane gas, which is a potent greenhouse gas, and LNG related methane emissions may in the future be regulated by the EPA or by state regulations. Additionally, CNG fuel tanks, if damaged or improperly maintained, may rupture and the contents of the tank may rapidly decompress and result in death or injury. In 2007, a driver of a CNG van in Los Angeles was killed when the previously damaged tank he was fueling ruptured. These risks may expose us to liability for personal injury, wrongful death, property damage, pollution and other environmental damage. We may incur substantial liability and cost if damages are not covered by insurance or are in excess of policy limits. If CNG or LNG vehicles are perceived to be unsafe, it will harm our growth and negatively affect BAF’s ability to sell converted CNG vehicles, which would impair our financial performance.

Our business is heavily concentrated in the western United States, particularly in California and Arizona. Continuing economic downturns in these regions could adversely affect our business.

Our operations to date have been concentrated in California and Arizona. For the years ended December 31, 2008, 2009 and 2010, sales in California accounted for 44%, 49% and 49% respectively, and sales in Arizona accounted for 14%, 10% and 9%, respectively, of the total amount of gallons we delivered. For the nine month period ended September 30, 2011, sales in California and Arizona accounted for 56% and 10%, respectively, of the total amount of gallons we delivered. A decline in the economy in these areas could slow the rate of adoption of natural gas vehicles, reduce fuel consumption or reduce the availability of government grants, any of which could negatively affect our growth.

We provide financing to fleet customers for natural gas vehicles, which exposes our business to credit risks.

We loan to certain qualifying customers a portion of, and occasionally up to 100% of, the purchase price of natural gas vehicles. We may also lease vehicles to customers in the future. There are risks associated with providing financing or leasing that could cause us to lose money. Some of these risks include: most of the equipment financed consists of vehicles, which are mobile and easily damaged, lost or stolen, there is a risk the borrower may default on payments, we may not be able to bill properly or track payments in adequate fashion to sustain growth of this service, and the amount of capital available to us is limited and may not allow us to make loans required by customers. Some of our customers, such as taxi owners, may depend on the CNG vehicles that we finance or lease to them as their sole source of income, which may make it difficult for us to recover the collateral in a bankruptcy proceeding. Any disruption in the credit markets may further reduce the amount of capital available to us and an economic recession or continued high unemployment rates may increase the rate of default by borrowers, leading to an increase in losses on our loan portfolio. As of September 30, 2011, we had $5.0 million outstanding in loans provided to customers to finance natural gas vehicle purchases.

Our business is subject to a variety of governmental regulations that may restrict our business and may result in costs and penalties.

We are subject to a variety of federal, state and local laws and regulations relating to the environment, health and safety, labor and employment and taxation, among others. These laws and regulations are complex, change frequently and have tended to become more stringent over time. Failure to comply with these laws and regulations may result in a variety of administrative, civil and criminal enforcement measures, including assessment of monetary penalties and the imposition of remedial requirements. From time to time, as part of the regular overall evaluation of our operations, including newly acquired operations, we may be subject to compliance audits by regulatory authorities. In addition, any failure to comply with regulations related to the government procurement process at the federal, state or local level or restrictions on political activities and lobbying may result in administrative or financial penalties including being barred from providing services to governmental entities.

In connection with our LNG liquefaction activities and the landfill gas processing facility operated by DCEMB, we need or may need to apply for additional facility permits or licenses to address storm water or wastewater discharges, waste handling, and air emissions related to production activities or equipment operations. This may subject us to permitting conditions that may be onerous or costly. Compliance with laws and regulations and enforcement policies by regulatory agencies could require us to make material expenditures and may distract our officers, directors and employees from the operation of our business.

We may not be successful in developing or expanding our biomethane, or renewable natural gas, business.

In November 2010, we announced that we entered into an agreement to develop a pipeline quality biomethane project at a Republic Services owned landfill outside of Detroit, Michigan. We are also in the process of expanding our operations at our biomethane production facility at the McCommas Bluff landfill outside of Dallas, Texas. In addition, we are seeking to expand our biomethane business by pursuing additional projects. Biomethane production represents a new area of investment and operations for us, and we may not be successful in developing these projects and generating a financial return from our investment. Historically, projects that produce pipeline quality biomethane, or renewable natural gas, have often failed due to the volatile prices of conventional natural gas, unpredictable biomethane production levels and technological difficulties and costs associated with operating the production facilities. Our ability to succeed in expanding our McCommas Bluff project and developing our project in Michigan and other projects we may secure in the future depends on our ability to obtain necessary financing, successfully manage the construction and operation of biomethane production facilities and our ability to sell and market the biomethane at substantial premiums to recent conventional natural gas prices. If we are unsuccessful in obtaining necessary financing or managing the construction and operation of our biomethane production facilities, or if we are unable to sell and market biomethane at a premium to conventional natural gas prices, our business and financial results may be materially and adversely affected. In addition, the California Energy Commission is considering revising existing rules that allow California utilities to classify as a bundled renewable energy credit any in-state electricity generation using out-of-state biomethane. If we can not sell biomethane produced outside of the state of California into California for use as an RPS compliant fuel, it would likely impair our ability to obtain premium prices for biomethane. In the absence of state and federal programs that support premium prices for renewable natural gas, we will be unable to generate profit and financial return from these investments, and our financial results could be materially and adversely affected.

Operational issues, permitting and other factors at DCEMB's landfill gas processing facility may adversely affect both DCEMB's ability to supply biomethane and our operating results.

In August 2008, we acquired our 70% interest in DCE, which owns 100% of DCEMB. DCEMB is a party to a 15-year gas sale agreement with Shell Energy North America (US) L.P. ("Shell") for the sale to Shell of specified levels of biomethane produced by DCEMB's landfill gas processing facility. There is, however, no guarantee that DCEMB will be able to produce or sell up to the maximum volumes called for under the agreement or produce biomethane that meets the relevant pipeline specification. DCEMB's ability to produce such volumes of biomethane depends on a number of factors beyond DCEMB's control, including, but not limited to, the availability and composition of the landfill gas that is collected, successful permitting, the operation of the landfill by the City of Dallas, the reliability of the processing facility's critical equipment and weather conditions. The DCEMB facility is subject to periods of reduced production or non-production due to upgrades, maintenance, repairs and other factors. For example, as part of an operational upgrade in March 2009, the facility was shut down for approximately one month. Also, on June 12, 2009, the facility was taken offline for repairs that were completed on July 2, 2009 and the facility was taken offline for upgrades from September 20, 2010 until September 25, 2010. Severe winter weather in Texas resulted in power outages and broken equipment in February 2011, resulting in a week of down time and an extended period during which the plant operated at half capacity. Further, production has been negatively affected by the recent severe drought and high temperature conditions in Texas. Future operational upgrades, including planned expansion of the plant, or complications in the operations of the facility could require additional shutdowns during 2011, and accordingly, DCEMB's revenues may fluctuate from quarter to quarter.

Our quarterly results of operations have not been predictable in the past and have fluctuated significantly and may not be predictable and may fluctuate in the future.

Our quarterly results of operations have historically experienced significant fluctuations. Our net losses (income) were approximately $5.4 million, $3.2 million, $12.1 million, $23.7 million, $6.5 million, $6.4 million, $18.5 million, $1.9 million, $24.4 million, $(9.9) million, $1.8 million, $(13.8) million, $9.8 million, $5.6 million and $11.4 million for the three months ended March 31, 2008, June 30, 2008, September 30, 2008, December 31, 2008, March 31, 2009, June 30, 2009, September 30, 2009, December 31, 2009, March 31, 2010, June 30, 2010, September 30, 2010, December 31, 2010, March 31, 2011, June 30, 2011 and September 30, 2011 respectively. Our quarterly results may fluctuate significantly as a result of a variety of factors, many of which are beyond our control. In particular, if our stock price increases or decreases in future periods during which our Series I warrants are outstanding, we will be required to recognize corresponding losses or gains related to the valuation of the Series I warrants that could materially impact our results of operations. If our quarterly results of operations fall below the expectations of securities analysts or investors, the price of our common stock could decline substantially. Fluctuations in our quarterly results of operations may be due to a number of factors, including, but not limited to, our ability to increase sales to existing customers and attract new customers, the addition or loss of large customers, construction cost overruns, downtime at our facilities (including any shutdowns of DCEMB's landfill gas processing facility), the amount and timing of operating costs, unanticipated expenses, capital expenditures related to the maintenance and expansion of our business, operations and infrastructure, our debt service obligations, changes in the price of natural gas, changes in the prices of CNG and LNG relative to gasoline and diesel, changes in our pricing policies or those of our competitors, fluctuation in the value of our natural gas futures contracts, the costs related to the acquisition of assets or businesses, regulatory changes, and geopolitical events such as war, threat of war or terrorist actions. Investors in our stock should not rely on the results of one quarter as an indication of future performance as our quarterly revenues and results of operations may vary significantly in the future. Therefore, period-to-period comparisons of our operating results may not be meaningful.

The future price of our common stock or the offering price of our common stock in future offerings could result in a reduction of the exercise price of our Series I warrants and result in dilution of our common stock.

We issued Series I warrants to purchase up to 3,314,394 shares of our common stock in connection with our registered direct offering completed in November 2008. 2,130,682 of the Series I warrants remain outstanding as of September 30, 2011. These warrants contain provisions that require an adjustment in the exercise price of the Series I warrants in the event that we price any offering of common stock at a price below the current exercise price, $12.68 per share, which, if we do, could result in a dilution of our common stock.

Sales of outstanding shares of our stock into the market in the future could cause the market price of our stock to drop significantly, even if our business is doing well.

If our stockholders sell, or indicate an intention to sell, substantial amounts of our common stock in the public market, the trading price of our common stock could decline. As of September 30, 2011, 70,382,655 shares of our common stock were outstanding. The 11,500,000 shares sold in our initial public offering, the 4,419,192 shares of common stock and the 2,130,682 shares of common stock subject to outstanding Series I warrants sold in our registered direct offering that closed on November 3, 2008, the 9,430,000 shares of our common stock sold in our common stock offering that closed on July 1, 2009 and the 3,450,000 shares of our common stock sold in our common stock offering that closed on November 11, 2010, are freely tradable without restriction or further registration under federal securities laws unless purchased by our affiliates.

In addition, upon the closing of our acquisition of IMW, we issued 4,017,408 shares of our common stock which are also registered for immediate resale. We issued an additional 601,926 shares to the IMW shareholder in January 2011. IMW's shareholder had sold 3,633,468 shares of our common stock as of September 30, 2011.

Shares held by non-affiliates for more than six months may generally be sold without restriction, other than a current public information requirement, and may be sold freely without any restrictions after one year. All other outstanding shares of common stock may be sold under Rule 144 under the Securities Act, subject to applicable restrictions.

In addition, as of September 30, 2011, there were 10,753,026 shares underlying outstanding options and 17,130,682 shares underlying outstanding warrants (including the 2,130,682 Series I warrant shares sold in our registered direct offering which closed on November 3, 2008). Further, as of September 30, 2011, there were 13,164,557 shares underlying the convertible notes we issued in July and August 2011. All shares subject to outstanding options, warrants and convertible notes are eligible for sale in the public market to the extent permitted by the provisions of various option and warrant agreements and Rule 144, or have been registered under the Securities Act of 1933, as amended. If these additional shares are sold, or if it is perceived that they will be sold in the public market, the trading price of our stock could decline.

Further, as of September 30, 2011, 16,539,720 shares of our stock held by our co-founder and board member T. Boone Pickens are subject to pledge agreements with banks. Should one or more of the banks be forced to sell the shares subject to the pledge, the trading price of our stock could also decline. In addition, a number of our directors and executive officers have entered into Rule 10b5-1 Sales Plans with a broker to sell shares of our common stock that they hold or that may be acquired upon the exercise of stock options. Sales under these plans will occur automatically without further action by the director or officer once the price and/or date parameters of the particular selling plan are achieved. As of September 30, 2011, 592,102 shares in the aggregate were subject to future sales by our named executive officers and directors under these selling plans. All sales of common stock under the plans will be reported through appropriate filings with the SEC.

A significant portion of our stock is beneficially owned by a single stockholder whose interests may differ from yours and who will be able to exert significant influence over our corporate decisions, including a change of control.

As of September 30, 2011, T. Boone Pickens and affiliates (including Madeleine Pickens, his wife) owned in the aggregate 26% of our outstanding shares of common stock and beneficially owned in the aggregate approximately 39% of the outstanding shares of our common stock, inclusive of the 15,000,000 shares underlying a warrant held by Mr. Pickens. As a result, Mr. Pickens will be able to influence or control matters requiring approval by our stockholders, including the election of directors and the approval of mergers, acquisitions or other extraordinary transactions. Mr. Pickens may have interests that differ from yours and may vote in a way with which you disagree and which may be adverse to your interests. This concentration of ownership may have the effect of delaying, preventing or deterring a change of control of our company, could deprive our stockholders of an opportunity to receive a premium for their stock as part of a sale of our company, and might ultimately affect the market price of our stock. Conversely, this concentration may facilitate a change in control at a time when you and other investors may prefer not to sell.

Item 2.—Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3.—Defaults upon Senior Securities

None.

Item 4.—(Removed and Reserved)

Item 5.—Other Information

None.

Item 6.—Exhibits

(a) Exhibits

4.6	Form of Convertible Promissory Note. (Filed as Exhibit 4.6 to Form 8-K, as filed with the Securities and Exchange Commission on July 11, 2011, and incorporated herein by reference.)
4.7	Form of Convertible Promissory Note. (Filed as Exhibit 4.7 to Form 8-K, as filed with the Securities and Exchange Commission on August 30, 2011, and incorporated herein by reference.)
10.58	Loan Agreement, dated July 11, 2011, by and among Clean Energy Fuels Corp., Chesapeake NG Ventures Corporation and Chesapeake Energy Corporation. (Filed as Exhibit 10.58 to Form 8-K, as filed with the Securities and Exchange Commission on July 11, 2011, and incorporated herein by reference.)
10.59	Registration Rights Agreement, dated July 11, 2011, by and among Clean Energy Fuels Corp. and Chesapeake NG Ventures Corporation. (Filed as Exhibit 10.59 to Form 8-K, as filed with the Securities and Exchange Commission on July 11, 2011, and incorporated herein by reference.)
10.60	Form of Convertible Note Purchase Agreement. (Filed as Exhibit 10.60 to Form 8-K, as filed with the Securities and Exchange Commission on August 30, 2011, and incorporated herein by reference.)
10.61	Form of Registration Rights Agreement. (Filed as Exhibit 10.61 to Form 8-K, as filed with the Securities and Exchange Commission on August 30, 2011, and incorporated herein by reference.)
31.1*	Certification of Andrew J. Littlefair, President and Chief Executive Officer, pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities and Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Richard R. Wheeler, Chief Financial Officer, pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities and Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, executed by Andrew J. Littlefair, President and Chief Executive Officer, and Richard R. Wheeler, Chief Financial Officer.
101†	The following materials from the Company's Quarterly Report of Form 10-Q for the quarter ended September 30, 2011, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets at December 31, 2010 and September 30, 2011; (ii) Condensed Consolidated Statement of Operations for the Three Months and Nine Months Ended September 30, 2010 and 2011; (iii) Condensed Consolidated Statements of Cash Flows for the Nine Months ended September 30, 2010 and 2011; and (iv) Notes to Condensed Consolidated Financial Statements, tagged as block of text.

* Filed herewith.

† Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CLEAN ENERGY FUELS CORP.

Date: November 8, 2011

By: /s/ RICHARD R. WHEELER

Richard R. Wheeler
Chief Financial Officer
(Principal financial officer and duly authorized to sign on behalf of the registrant)

Exhibit 31.1

Certifications

I, Andrew J. Littlefair, certify that:

1. I have reviewed this Form 10-Q of Clean Energy Fuels Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2011

/s/ ANDREW J. LITTLEFAIR

Andrew J. Littlefair,
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

Certifications

I, Richard R. Wheeler, certify that:

1. I have reviewed this Form 10-Q of Clean Energy Fuels Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting.

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 8, 2011

/s/ RICHARD R. WHEELER

Richard R. Wheeler,
Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION REQUIRED BY
SECTION 1350 OF TITLE 18 OF THE UNITED STATES CODE

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned hereby certifies in his capacity as the specified officer of Clean Energy Fuels Corp. (the “Company”) that, to the best of his knowledge, the quarterly report of the Company on Form 10-Q for the fiscal quarter ended September 30, 2011 fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, and that the information contained in such report fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods presented in the financial statements included in such report.

Dated: November 8, 2011

/s/ ANDREW J. LITTLEFAIR
Name: Andrew J. Littlefair
Title: *President and Chief Executive Officer*
(Principal Executive Officer)

Dated: November 8, 2011

/s/ RICHARD R. WHEELER
Name: Richard R. Wheeler
Title: *Chief Financial Officer*
(Principal Financial Officer)

This certification accompanies this Report on Form 10-Q pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

Attachment 3.3

Attachment B

ROGER WARE
CIRRICULUM VITAE
AND LETTER DATED JANUARY 19, 2012
RESPONDING TO THE EVIDENCE OF
ESAC, CORIX AND PROFESSOR JACCARD

APPENDIX 1

CURRICULUM VITAE

July 2011

NAME:	Roger Ware
CURRENT POSITION:	Professor, Queen's University
OFFICE ADDRESS:	Department of Economics Queen's University Kingston, Ontario K7L 3N6 Tel: (613) 533 2295 Fax: (613) 544 7043
EMAIL:	**ware@qed.econ.queensu.ca**
HOME ADDRESS:	241 Alwington Place Kingston, Ontario K7L 4P9 (613) 544 7043
DATE AND PLACE OF BIRTH:	February 23, 1951 - England
CITIZENSHIP:	Canadian and U.K.
EDUCATION:	
	B.A. Honours (Economics) Cambridge University Awarded June 1972
	M.A. (Cantab) awarded July 31, 1976
	M.A. (Industrial Economics) University of Sussex, England Awarded December 1973
	Ph.D., Queen's University, Kingston, Canada, Awarded October 1981

APPENDIX 1

POSITIONS HELD:

July 1997 - present	Professor, Queen’s University
January 1991 - June 1997	Associate Professor, Queens University
August 1993 - August 1994	Holder of T.D.MacDonald Chair in Industrial Economics, Bureau of Competition Policy, Ottawa
1989 - December 1990	Associate Professor, University of Toronto
1987-88	Visiting Associate Professor, Department of Economics, University of California, Berkeley.
1986-87	Sabbatical Leave. Visiting Research Scholar, Carleton University and National Bureau of Economic Research, Stanford University
July 1986	Promoted to Associate Professor with Tenure, University of Toronto.
1981-86	Assistant Professor (Economics), Erindale College, University of Toronto.
1980-81	Lecturer in Economics, Erindale College, University of Toronto.
1979-80	Instructor, Introductory Economics, Queen's University
1977-79	Various Tutorial and Research Assistantship Positions held, Queen's University.

POSITIONS HELD (continued)

1975-1977	U.K. Department of Industry, Industrial Policy Analysis and Briefing Division. Provided advice on government support for research and development, and special assistance schemes for industry. During this period I completed a cost-benefit study of cost sharing support for industrial development projects.
1973-1975	U.K. Department of Industry. Economic Assistant, working on an econometric forecasting model of U.K. trade flows. Promoted to Senior Economic Assistant, October 1974.

AWARDS:

Holder of R. Samuel Mclaughlin Scholarships for graduate studies at Queen's University, 1977-78, 1978-79, 1980-81 sessions.

Awarded a Social Sciences and Humanities Research Council Post Doctoral Fellowship for 1983-84, renewed for 1984-85.

SSHRC Research Grants:
1983: $6,760
1989: $14,250
1992: (3 year grant in the amounts of:) $19,500, $4,300, $2,300.

Awarded an SSHRC Leave Fellowship, 1986-87.

MAJOR FIELDS OF RESEARCH INTEREST:

Industrial Organization:

Antitrust Economics and Competition Policy
Strategic Behaviour
Research and Development
Dynamic Modelling
Trade and Industrial Policy

Public Economics

BOOKS

Industrial Organization: a Strategic Approach. (with Jeffrey Church, University of Calgary) 2000. Boston: Irwin McGraw-Hill.

JOURNAL PUBLICATIONS

"Identifying Market Power in Natural Gas Storage" with David Brown and David Harding, 2008 *Canadian Competition Record.* Vol 23, No. 1.

"Efficiencies Analysis for Retail Sector Mergers," (with John Blakney) *European Competition Journal*, November 2006, pp. 285-310.

"Does Canada Pipe Really Have Market Power?" (with A. Basiliauskas) 2005 *Canadian Competition Record.* Vol 22, No. 2.

"Predatory Pricing In Canada, The United States And Europe: Crouching Tiger or Hidden Dragon," with Brian Facey, December 2003, *World Competition Review*

"Is Competition Law 'Beyond the Ken of Judges'?" 2001. *Canadian Competition Record.* Vol 20, No. 3.

"Efficiencies and the Propane Case" (2000), *International Antitrust Bulletin.*

"A Dynamic Model of Endogenous Trade Policy," (2001) joint with Bev Lapham, *Canadian Journal of Economics.*

"Interac, Essential Facilities and Access to Electronic Funds Networks: a Comment on Mathewson and Quigley," (1998) with Brian Rivard, *Canadian Competition Record,* 18: 12-21.

"Abuse of Dominance under the 1986 Canadian *Competition Act*," with Jeffrey Church, (1998) *Review of Industrial Organization*, 13: 85-129.

"Trade Dress and Pharmaceuticals: Efficiency, Competition and Intellectual Property Rights," 1997 with Jeffrey Church, *Policy Options*, September.

"Delegation, Market Share and the Limit Price in Sequential Entry Models," (1996) with Jeffrey Church, *International Journal of Industrial Organization,* 14: 575-609.

"Public Firms as Regulatory Instruments with Cost Uncertainty," (1996) with Devon Garvie, *Canadian Journal of Economics,* XXIX No. 2: 357-378.

"Raising Rivals' Costs and Alcoa: a Rejoinder" (1994) *Canadian Competition Policy Record*, October.

"Understanding Raising Rivals' Costs: a Canadian Perspective," (1994) *Canadian Competition Policy Record*, March.

"Markov Puppy Dogs and Related Animals," (1994) with Bev Lapham, *International Journal of Industrial Organization*, 12, 569-593.

"A Sequential Entry Model with Strategic Use of Excess Capacity," (1993) with Brad Barham, University of Wisconsin, *Canadian Journal of Economics*, XXVI, No. 2, 286-298.

"Evolutionary Stability in the Repeated Prisoner's Dilemma," (1989) with Joseph Farrell, *Theoretical Population Biology*, 36, 161-166.

"Eliminating Price Supports: a Political Economy Perspective," (1989) with Tracy Lewis and Robert Feenstra, *Journal of Public Economics*, 40, 159-185.

"Forward Markets, Currency Options and the Hedging of Exchange Risk," (1988) with Ralph Winter, *Journal of International Economics*, 25, 291-302.

Review of The New Industrial Organization: Market Forces and Strategic Behavior by Alexis Jacquemin (1988), *Southern Economic Journal*.

"A Theory of Market Structure with Sequential Entry" (1987), with Curtis Eaton, *Rand Journal of Economics*, Vol. 18, #1, 1-16.

"A Model of Public Enterprise with Entry" (1986), *Canadian Journal of Economics*, XIX, 642-655.

"Long Term Bilateral Monopoly: The Case of a Resource" (1986), with Tracy Lewis and Robin Lindsey, *Rand Journal of Economics*, vol. 17, No. 1.

"Public Pricing Under Imperfect Competition" (1986), with Ralph Winter, *International Journal of Industrial Organization*, 4, 87-97.

"On the Shapes of Market Lattices in Loschian Spatial Models" (1986), with Mukesh Eswaran, *Journal of Regional Science*."Inventory Holding as a Strategic Weapon to Deter Entry" (1985) *Economica*, 52, 93-102.

"Lumpy Investment in a Growing Differentiated Market" (1984), *Economica*, 51, 377-391

"Sunk Costs and Strategic Commitment: A Proposed Three-Stage Equilibrium" (1984), *Economic Journal*, 94, 370-378.

"Strategic Timing and Pricing of a Substitute in a Cartelized Resource Market" (1983), with Nancy Gallini and Tracy Lewis, *Canadian Journal of Economics*, XVI, 429-446.

Three Essays on the Economics of Differentiated Markets (1981), Ph.D. Thesis, Queen's University,

"The Relationship Between Efficiency and Technical change" (1977), in *Industrial Efficiency and the Role of Government*, edited by C.Bowe, HMSO, London.

ARTICLES IN BOOKS

Publication (on CD) of paper “The Role of Price Correlations" contained in proceedings of Canadian Bar Association 2004 Annual Fall Conference on Competition Law

Publication (on CD) of paper “Recent legislative changes: is competition law becoming too industry specific?"contained in proceedings of Canadian Bar Association 2002 Annual Fall Conference on Competition Law

“The Effect of Uncertainty on theValue of Strategic Commitment.” 2002. With B.C.Eaton, in volume, Applied Microeconomic Theory: Selected Essays of B. Curtis Eaton. Northampton, MA: Edward Elgar.

“Leading Edge Issues in the Economics of Competition Law,” in J.B.Musgrove ed., *Competition Law for the 21st Century*, (proceedings of the 1998 Canadian Bar Association), Juris Publishing.

“Network Industries, Intellectual Property Rights, and Competition Policy.” 1998. in N. Gallini and R. Anderson ed., *Competition Policy, Intellectual Property Rights and International Economic Integration* Industry Canada Research Series, The University of Calgary Press.

"Entry Deterrence" (1991) chapter in *New Developments in Industrial Organization* ed. by Manfredi La Manna and George Norman, Edward Elgar Publishing, London.

Review of Market Structure and Innovation, by M.I.Kamien and N.L.Schwartz (1983), *Canadian Journal of Economics*.

ARTICLES SUBMMITTED TO JOURNALS

“Price Cycles and Price Leadership in Gasoline Markets: New Evidence from Canada” co-authored with David Byrne, submitted to *Rand Journal of Economics*, August 2011.

WORKING PAPERS

“Price Cycles and Price Leadership in Gasoline Markets: New Evidence from

Canada" co-authored with David Byrne, SSRN Working Paper.

RECENT PROFESSIONAL ACTIVITIES

Participated in a panel session on Competition Policy at the CEA Meetings, Ottawa, June 2011.

Participated in a panel session on Competition Policy at the CEA Meetings, Vancouver, June 2008.

Presented the paper "Market Power in Natural Gas", co-authored with David Brown, Ontario Energy Board, and David Harding, Competition Bureau at the 2007 Canadian Economics Association Meetings, Halifax, June 2007.

Refereeing on a regular basis for *American Economic Review, Canadian Journal of Economics, The International Journal of Industrial Organization*, *The Journal of Industrial Economics*, and occasionally for *Journal of International Economics,* and *International Economic Review.*

Presentations at the Canadian Bar Association annual conference, 2001, 2002, 2003, 2004.

Presentation of a paper "Efficiencies and the Propane Case" at the CBA Competition Law Section Meetings, Ottawa, September 2000.

Organizer, Paper presenter and Chair of two Sessions on *Competition Act* at 1997 Canadian Economics Association Annual Conference, St. John's, Nfld., June 1997.

Organizer and Chair of Panel Session on Canadian Competition Policy at 1992 Canadian Economics Association Annual Conference, Charlottetown, June 1992.

Co-Organizer of UBC Conference on Industrial Organization, July 1993

Organizer of a Conference on *Barriers to Entry*, March 1995, at the Bureau of Competition Policy, Ottawa.

Holder of the T.D.McDonald Chair in Industrial Organization at the Competition Bureau, Ottawa, from 1993-94.

Membership of Professional Societies -

Member of Canadian Economics Association

REPORT ON THE COMPETITIVE EFFECTS OF FORTISBC ENERGY UTILITIES' PROVISION OF ALTERNATIVE ENERGY SOLUTIONS

Dr. Roger Ware
Professor of Economics, Queen's University

January 19, 2012

Table of Contents

I. QUALIFICATIONS AND ASSIGNMENT

1. My name is Roger Ware. I am a Full Professor of Economics at Queen's University in Kingston, Ontario. I have held this position since 1996. I have been retained by FortisBC Energy Inc. ("FEI") to discuss certain matters that have been raised by intervenors in the *AES Inquiry* before the British Columbia Utilities Commission (the "Inquiry"). I have been asked to review a number of the exhibits filed in the Inquiry (set out below), and provide comments and opinion on the following matters:

    a. What distinguishes fair competition versus unfair competition?

    b. Assuming that FEI adheres to the policies and practices described in the documents reviewed (set out below), does FEI have an unfair competitive advantage in the thermal energy systems market by virtue of the fact that it also provides natural gas service as a separate regulated class of service within the same utility?

2. The following is a summary of my qualifications in the area of Economics, Competition Policy and Industrial Organization. I have held full-time faculty positions for 31 years at the University of Toronto and Queen's University, and a visiting position at the University of California, Berkeley in 1987-88. I have published many articles in the area of Industrial Organization and Competition Policy, and a major textbook on the Economics of Industrial Organization, much of which is devoted to Antitrust Economics and Regulation.[1] I teach three or four courses each year at both the undergraduate and graduate level, covering the Economics of Regulation and Industrial Organization and have taught Competition Law in the Queen's University Faculty of Law on several occasions. From 1993-94, I held the T.D. MacDonald Chair at the Competition Bureau, and provided advice to the Director and other officers on many cases and issues. I have testified, given evidence, and consulted in several matters involving competition and regulatory issues. Finally, I have been an invited speaker to the Canadian Bar Association Annual Competition Law Conference on several occasions.

3. A full version of my curriculum vitae is attached as an Appendix to this report.

---

1 Church, J.R. and R. Ware. Industrial Organization: A Strategic Approach (2000) San Francisco: McGraw-Hill-Irwin, 2000.

4. In preparation for my report, I have reviewed the documents that have been filed in this proceeding, in particular:

   a. Exhibit A2-1, Letter dated May 25, 2011 – Commission Staff filing Energy Services Association of Canada application dated April 27, 2011

   b. Exhibit A2-2, Letter dated May 25, 2011 – Commission Staff filing Corix Utilities May 6, 2011 letter supporting the Energy Services Association of Canada April 27, 2011 Application

   c. Exhibit B-2, Written Evidence of FortisBC Energy Utilities, sections 1, 2, and 6, and Appendix F.5 (GT&C 12A);

   d. FortisBC Energy Utilities responses to information requests filed in the Inquiry (BCUC 1.17.1 and BCUC 1.100.2);

   e. Exhibit C12-5, Written Evidence of Dr. Mark Jaccard (evidence submitted by Corix Utilities Inc.);

   f. Exhibit C12-6, Written Evidence of Corix Utilities Inc.;

   g. Exhibit C1-5, Written Evidence of Energy Services Association of Canada; and

   h. all other documents and websites referenced as footnotes herein.

II. ASSUMPTIONS

I have been asked by FEI to assume the following for the purposes of my opinions:

a. Assumed Facts About Natural Gas Class of Service

   i. The FortisBC Energy Utilities are investor-owned utilities. They are wholly owned by FortisBC Holdings Inc., which is a wholly owned subsidiary of Fortis Inc. Fortis Inc. is a publically traded company that has diverse holdings in Canada and abroad.

   ii. The FortisBC Energy Utilities deliver natural gas service to approximately 950,000 customers in 125 British Columbia communities, through three legal entities, FEI, FEVI and FEW. FEVI serves Vancouver Island, Sunshine Coast and Powell River. FEW serves Whistler. FEI serves the

Lower Mainland, Columbia and Interior regions. It also serves Fort Nelson as a distinct operating area, with a separate rate base and its own rates.

iii. Each of FEI, FEVI and FEW are the only natural gas distribution utilities in their respective service areas.

iv. The FortisBC Energy Utilities deliver most of the natural gas consumed in British Columbia.

v. Pursuant to the provisions of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473 (the "Act"), the FortisBC Energy Utilities are subject to regulation by the British Columbia Utilities Commission (the "Commission").

vi. Pursuant to the Act and various orders issued by the Commission, the FortisBC Energy Utilities are required to charge rates for natural gas service under Commission approved tariffs and, in prescribed circumstances, to seek approval from the Commission to construct or operate public utility facilities (called a Certificate of Public Convenience and Necessity or "CPCN").

vii. The FortisBC Energy Utilities are obligated under the Act and Commission orders to connect new natural gas customers to the natural gas distribution system. There are Commission approved tests and rate structures in place to determine any contribution the new customer must make to help make existing natural gas customers whole. Once connected, new customers must pay rates under Commission approved tariffs for natural gas service.

viii. The approved tariffs for the FortisBC Energy Utilities' natural gas service are based on cost of service principles, meaning that: (a) the natural gas rates charged by each of the utilities [or the service area in the case of Fort Nelson] are set to generate sufficient revenues to recover the utility's total costs of providing natural gas service each year; and (b) in designing natural gas rates to recover the total cost of providing natural gas service each year, customer classes (e.g. commercial, residential etc.) are generally charged rates that are based on the cost of serving that particular customer class.

ix. The FortisBC Energy Utilities employ a shared services model, meaning that Operating and Maintenance expenses are incurred by FEI, and a portion of the costs are allocated to each of FEVI, FEW and Fort Nelson Service Area based on Commission-approved allocators.

x. In the case of each of FEI, FEVI, FEW and Fort Nelson, rates reflect capital incurred by the utility.

xi. The cost of capital for each of the FortisBC Energy Utilities' natural gas service is determined as follows. The Commission has determined the appropriate capital structure (debt/equity) for rate setting purposes. For each utility, debt costs are approved by the Commission and are a flow through cost in rates, i.e. are flowed to customers without mark-up by the utility. The Return on Equity for rate setting purposes is set by the Commission.

1. The Commission has used FEI's ROE as a "benchmark", and other utilities in the Province, including FEVI and FEW, have their ROE determined on a relative basis to the benchmark based on their relative business risks as determined by the Commission.
2. FEI, FEW and FEVI engage in separate debt financing with debt rates approved the Commission.
3. In the case of Fort Nelson Service Area, although a separate service area within FEI with a separate rate base and rate structures, FEI's ROE, capital structure and cost of debt are used in rate-setting.

xii. The Act allows for regulated public utilities to provide different "classes of service." In 2010, the Commission approved for FEI a new class of service for Thermal Energy Services, or "TES", as distinct from the provision of natural gas service. Among the FortisBC Energy Utilities, only FEI is providing TES.

b. Assumed Facts About Thermal Energy Services

i. For the purposes of the questions set out above, on which I have been asked to opine, the phrase "TES Market" refers to the provision of TES as described in sections 6.1, 6.2 and 6.3 of Exhibit B-2, Written Evidence of FortisBC Energy Utilities.

ii. The FortisBC Energy Utilities intend to provide TES as described in Exhibit B-2, Written Evidence of FortisBC, sections 6.1, 6.2, and 6.3 ("TES Services"), through FortisBC Energy Inc. as a separate class of service within the existing utility. As set out above, FortisBC Energy Inc. also provides a natural gas class of service. FEI will offer TES pursuant to the provisions of a Commission-approved rate tariff (the current tariff provision is called GT&C 12A).

iii. FortisBC Energy Utilities present themselves to the public as providers of integrated energy solutions, which includes natural gas and TES. FEI will use the FortisBC name in promoting both TES and natural gas services. The name "FortisBC" is owned by the parent company and used under licence by the utilities. There is also a FortisBC electric utility in British Columbia, with a partially overlapping service area with FEI. All of the FortisBC companies are under a unified executive structure. FEI, FEVI, and FEW are fully integrated in terms of management and employees, whereas the electric utility operates separately (although with common executives).

iv. All costs and revenues associated with FEI's TES services will be recorded in a deferral account (the "Thermal Energy Services Deferral Account") as described in BCUC 1.17.2 and 1.100.2 and these costs will only be recovered from the customers of the TES class of service and not natural gas customers. Currently, there is an unrecovered balance in the TES Deferral Account, as there have been no TES revenues to date.

v. Despite the existence of multiple classes of service, FEI is an integrated company. FEI is segregating TES from natural gas class of service for ratemaking purposes to ensure that rates paid by natural gas customers and TES customers are fair, just and reasonable as defined under the Act. I have been asked to assume, for the purposes of my opinions, that a cost allocation – including assignment of direct costs and a fair allocation of overhead - has been approved by the Commission.

vi. FortisBC Energy Inc. will compete in the TES Market with Corix Utilities Inc. and some or all of the members of the Energy Association of Canada. Some real estate developers also construct and operate their own systems. None of these potential competitors (with a very minor exception in the case of Corix) provide regulated natural gas distribution services in British Columbia.

vii. All competitors in the TES Market – FEI or otherwise - will be subject to regulation by the Commission under the Act for the provision of TES, unless there is a legislative exemption created. This is because the nature of the service is one that is defined in the Act as being subject to regulation. For FEI, in the event that TES services were exempted, the Commission would still oversee the allocation of costs to that service by virtue of regulating the natural gas business.

viii. The FortisBC Energy Utilities have Commission approved incentive programs to encourage energy efficiency and conservation. Any Commission-approved incentives provided by the FortisBC Energy Utilities to encourage the adoption of TES will be made available to consumers of TES on a non-discriminatory basis (regardless of TES provider) by FEI staff .

III. BACKGROUND

5. Several intervenors, including Corix Utilities Inc. and the Energy Services Association of Canada ("ESAC") have alleged that FEI's entry into the market for the provision of thermal energy services would have unfavourable consequences that would impede an otherwise efficient competitive market outcome. Specifically, the intervenors make the following comments and allegations regarding unfair competition in the thermal energy system market:

    a. By Corix Utilities Inc., for instance:

    > The Commission must reconcile the ratepayer interest in public utility regulation with the public interest in a competitive TES market. The span of its regulatory reach is defined by its statutory mandate – which is the regulation of public utilities. Within that mandate however, the Commission has considerable discretion over how it regulates public utilities engaged in TES which, in turn, will influence the TES market. With this in mind, the Commission has an important role in several respects:
    >
    > > First, where a competitive market can exist for the provision of TES, the economic regulator must ensure that the natural monopolies it regulates (electric, gas, other) do not use advantages related to their monopoly powers (customer information, improper allocation of risk, cross-subsidization, etc.) to thwart fair competition. This may require several stipulations for the practices of the monopoly. Establishing rules for participation by existing non-TES utilities in these TES market protects both the existing non-TES utility customer interests and the competitive market conditions.[2]
    >
    > The new TES business trades on FEI's visibility as a natural gas monopoly to promote its TES business. FEI markets "energy solutions" (which include TES along with natural gas services) directly to its existing natural gas customers. FEI's ability to leverage its monopoly position in the natural gas market to promote its TES business provides a significant market advantage not enjoyed by other TES competitors.
    >
    > In Corix's experience, market recognition as an experienced TES provider is a valuable competitive advantage. Corix is therefore concerned that FEI's integration of the two business lines under the FEI brand, will lead to customer confusion. The natural gas utility has, or is perceived to have, a franchise right and obligation to serve. Offering TES under the same banner may create the impression that the utility franchise also extends to

---

[2] Exhibit C12-5, Written Evidence of Dr. Mark Jaccard (evidence submitted by Corix Utilities Inc.), at p. 13.

providing TES service (i.e., the customer has only one option), or that discounts are available by purchasing "bundled" service. Corix is concerned that FEI's promotion of its TES business will play on these vulnerabilities, and allow FEI to take advantage of the market power of its natural gas business to support the TES business.

…

If internal governance does not restrict the access the TES business has to the natural gas business resources and does not properly allocate the true cost of those resources to the TES business, then the FEI natural gas ratepayers are subsidizing the TES business in large measure, which in turn gives FEI an unfair competitive advantage in the TES market. Further, FEI marketing of its TES offerings will promote that advantage to customers. The Commission should be vigilant to prevent any such abuse of its monopoly utility position.[3]

b. By the Energy Services Association of Canada, for instance:

As a matter of principle regulated utilities such as the FEU should not be permitted to lever their privileged positions to unfairly stifle competition in unregulated markets. It is imperative, for the protection of the interests of (i) the utility's rate payers, (ii) businesses operating in competitive markets, particularly those in some way connected to the monopoly operated by the utility, and (iii) the public at large, that a clear set of rules be established and enforced to guide the conduct of the utility and to ensure fairness and transparency. The absence of a clear set of rules or a willingness to enforce the rules will have an immediate dampening effect on investment and competition and, ultimately, on innovation and new development.[4]

IV. SUMMARY OF OPINIONS

6. My findings and opinions are summarized as follows:

a. Fair competition between FEI and other suppliers offering products in the emerging TES market can exist within an appropriate regulatory framework.

b. In particular, various dimensions of unfair competition have been alleged, all involving a transfer of an advantage gained from FEI's gas utility business to its TES customers. The most commonly expressed concern is that FEI TES customers will benefit from cross-subsidization arising from FEI's gas utility

3 Exhibit C12-6, Written Evidence of Corix Utilities Inc., at pp. 9-11.

4 Exhibit C1-5, Written Evidence of Energy Services Association of Canada, at p.36.

business. In my opinion appropriate regulation can effectively prevent such cross-subsidization.

c. Other alleged dimensions of advantage are low costs of debt financing, artificially low business risks, and discriminatory access to market information. I show that each of these concerns is likely to be unfounded, or at least of very minor significance.

V. ASPECTS OF "FAIR" AND "UNFAIR" COMPETITION"

7. The claim has been expressed that FEI's presence in the TES marketplace would amount to unfair competition.[5] The core of these allegations would seem to be the following: first, that FEI has the capacity and the incentive to cross-subsidize its TES product offerings from its activities as a gas utility, i.e. in effect from its gas utility customers.[6] Second, that FEI will trade on its brand name and its established position in the marketplace to obtain an unfair advantage with potential TES customers, over newer independent rivals who have no such established brand, track record, or reputation.[7] Third, the argument has been made that FEI's TES projects will be able to obtain capital on a preferred basis because FEI's debt financing sources "are attached and co-mingled with a large base of regulated natural gas utility ratepayers."[8] Finally, it has been alleged that FEI's access to the data base of gas utility customers will confer an unfair advantage in marketing TES products.

---

5 "…[I]t is important that the [TES] market be truly competitive. This can only be the case if the BCUC ensures that incumbent public utilities do not use their existing assets, human resources and financial power to bias the competitive market." Exhibit C12-5, Written Evidence of Dr. Mark Jaccard (evidence submitted by Corix Utilities Inc.), at p. 6; and "The issue is fairness. Corix opposes FEI using its existing natural gas business to provide an unfair competitive advantage to its new TES business." Exhibit C12-6, Written Evidence of Corix Utilities Inc., at p. 8.

6 "[E]nsure that the natural gas rate payers of Fortis BC Energy are in no way supporting the AES endeavours of FortisBC Energy or its affiliates, inclusive of overhead costs, current or future cross-subsidization of cost of service, availability of capital, cost of capital subsidization." Exhibit C1-5, Written Evidence of Energy Services Association of Canada, at pp. 1-2.

7 "The FEI brand has a disproportionately large impact in the emerging TES market that has been funded by the natural gas ratepayers. … This approach leverages natural gas utility assets to create a competitive advantage subsidized by the gas customers." Exhibit C12-6, Written Evidence of Corix Utilities Inc., at p. 14.

8 Exhibit C1-5, Written Evidence of Energy Services Association of Canada, at p. 8.

8. It is worth noting that there is nothing unfair, ex-ante, about having FEI, a large gas utility, enter and compete in the market for TES projects. If FEI is able to operate and offer TES at a lower cost, then TES customers are better off. Subject to the safeguards I discuss below relating to cross-subsidization and other issues, FEI will bring an important competitive presence to the marketplace, and the rivalry generated by its participation will generate benefits for all TES customers.

9. In this section I begin by setting out a more precise definition of some of the terms used to support the claims of unfair competition. Having done so, I then offer my assessment of whether there is any substance to these claims.

A. Cross-Subsidization

10. Cross-subsidization is a term often used imprecisely to indicate that a firm or other entity is using a revenue stream from one product line to support a different product line or class. This might, for example, allow the subsidized product class to be offered at a lower price. Cross-subsidization can take place across spatial markets as well as between different products, e.g. where an airline subsidizes sparsely populated regional markets with its revenues from high density urban travel centres.

11. But how can we precisely identify cases of cross-subsidization?[9] The term "cross-subsidization" is often used and abused in equal measure. Although it may be tempting to allege that a company is cross-subsidizing product line B with its profits from product line A, these allegations must be examined while paying attention to the economics of the company and industry.

12. Central to the identification of cross-subsidization is the concept of Stand Alone Costs. Stand Alone Costs are defined for a given product class as the costs of producing that product class alone, in the absence of any other activities that the utility or entity is engaged in. For a regulated firm, provided that revenue for that product class is no greater than Stand Alone Costs, so defined, then that product class can be said to be subsidy free, i.e. it cannot be identified as subsidizing other products produced within the same Cost of Service regulated entity. So, for example, in the current context, if FEI's approved revenue requirement from

[9] Church, J.R. and R. Ware. Industrial Organization: A Strategic Approach (2000) San Francisco: McGraw-Hill-Irwin, 2000 at pp. 797-798.

the gas utility business does not exceed the accepted forecast of Stand Alone Costs of operating that business, then FEI cannot be said to be cross-subsidizing the TES product class from the natural gas ratepayers.[10]

13. A related concept is that of Incremental Cost. The incremental cost for FEI of operating TES is the additional cost incurred given that FEI is already operating its gas utility business. Provided that the revenues from the TES business exceed the incremental costs of operating that business, then TES product class passes the incremental cost test for cross-subsidization and cannot be identified as receiving any subsidy. In the present case where the TES business is starting up, costs exceed revenues in the short term but it is expected that incremental costs will be recovered in the longer term from TES customers.

14. These two concepts, Stand Alone Cost and Incremental Cost, provide bounds within which a product class can be said to be subsidy free. For a given product class, the range of revenue between covering incremental costs and up to Stand Alone Costs is said to be a subsidy free zone. In this zone, revenues are sufficiently high that this product class requires no subsidy from others, and sufficiently low that it cannot be said to be providing a subsidy to other products. Thus, in the context of FortisBC's TES business, provided that revenues fall between the bounds of incremental costs and stand alone costs, they are within the subsidy free zone and FEI cannot be said to be cross-subsidizing its TES business.

15. As an illustration, suppose a utility is producing two distinct product classes using some common capital facilities, facilities which are essential for the production of either product class. One thing that the formal tests reveal more clearly is that if, for example, FEI in a TES project is able to utilize shared common facilities already in place from its role as a gas utility, this may confer a cost advantage over a new entrant having to generate all of its TES investment de novo. But such a cost advantage would not satisfy an economic test for cross subsidization. This may seem "unfair" to the entrant, and there would admittedly be an

[10] Suppose that the fixed costs of the common facility are $F expressed on an annualized basis. If $P_g Q_g$ is the net revenue from sales of gas, then the Stand Alone Cost test requires that $P_g Q_g \leq F$. Suppose also that $P_e Q_e$ is the net revenue from sales of Electricity. The Incremental Cost Test requires that $P_e Q_e > 0$ i.e in words that the addition of a new product class can cover the incremental costs of supplying it. Provided that rates set for our hypothetical utility satisfy both of these tests, then one service cannot be said to be subsidizing the other (i.e., no conclusions regarding cross-subsidization can be made).

asymmetry between the two potential rivals in the TES market. But no valid claim can be made that the incumbent is cross subsidizing its TES sales from its gas utility business. Just because the incumbent has sunk investments from its gas utility business that can be efficiently utilized in part in new TES projects does not imply that any cross-subsidization is taking place. Rather, the presence of economies of scope between the gas and TES product classes is ensuring, at least when holding everything else constant, that the incumbent utility will be the low cost producer in the developing TES market.

16. Assuming that FEI is able to exploit economies of scope and bring correspondingly low costs to the TES marketplace, these low costs would exert a valuable disciplinary force on the costs of rival suppliers. Rival TES suppliers will be forced to keep their own costs down to a comparable level to FEI in order to win customer contracts. The net effect of such competition will benefit the TES customer, since inefficient TES suppliers will be discouraged from entering the market. On the contrary, if FEI is prevented from competing effectively in the TES marketplace, TES customers will no longer have access to a low cost producer, and therefore lose the corresponding benefits to competition created by having this low cost option.

B. Predatory Pricing

17. Another example of unfair competition would be predatory pricing. A firm engages in predatory pricing by lowering its price to drive rivals out of the market, and once the rivals exit the market, raises its prices. True predatory pricing is extremely rare; some antitrust economists have argued that it is essentially non-existent.[11]

18. There are several standard tests for the presence of predatory pricing, but among the most common is determining whether the incumbent firm is pricing a service or a range of services below an appropriate measure of cost. The cost measure generally favoured by antitrust economists is a measure of Average Avoidable Cost.

19. In the context of a utility producing two product classes, predatory pricing and cross subsidization are related and could be identified by essentially the same test. Only if the incumbent were selling electricity (product B) below the variable or avoidable cost of

[11] Kaplow, L. and C. Shapiro, “Antitrust,” in *Handbook of Law and Economics*, Oxford: North-Holland Elsevier, 2007, at pp. 1196 – 1197 and the references cited therein.

producing it, would the incumbent fail a cost based test for predatory pricing. This test is identical to the incremental cost test for cross subsidization.

C. Brand and Reputation

20. Some intervenors have argued that FEI will be able to compete unfairly in the TES market by trading on the customer goodwill and brand name recognition that has been derived from FEI's role as a gas utility.[12] But this is a misapprehension. A reputation for quality of service and reliability are attributes that should give an incumbent supplier an advantage, however temporary, over new and untested entrants. That is, consumers place a positive value on being able to trust a supplier to produce high quality TES products and to deliver them in a timely fashion. An incumbent advantage of exactly this kind would certainly be true in any other industry and one would expect it to be true in the developing TES marketplace. If FEI's TES business were required to disassociate itself from its brand and reputation, this requirement would destroy valuable information contained in the brand and introduce inefficiencies. In my opinion, use of the Fortis brand is a fair exercise of the utility's reputation to expand in other areas.

D. Does FEI have an unfair advantage in the cost of capital?

21. ESAC and Corix have expressed concern that FEI would have an unfair competitive advantage in access to debt financing, because of its "large base of regulated gas utility ratepayers."[13] If a lower cost of debt for TES projects is available to FEI through the pooling of its debt portfolio, the lower costs that are implied would be passed on to consumers and permit a more efficient market outcome. I would expect that other TES suppliers will also leverage their portfolio to achieve similar portfolio economies in their funding of TES business activities. Such pooling of debt portfolios is normal business practice in unregulated competitive markets and poses no threat of unfair competition in the regulated TES market.

E. Does FEI possess access to information that confers on it an unfair competitive advantage?

---

[12] Exhibit C12-6, Written Evidence of Corix Utilities Inc., at pp. 9-10, 14-15.

[13] Exhibit C1-5, Written Evidence of ESAC, at p.8.

22. Some intervenors have argued that the Commission should "regulate …the information, resources and market power that FEI may transfer to the TES business."[14] They allege that FEI's "unfettered access" to historical customer consumption data constitutes an unfair advantage and a potential source of valuable marketing information.[15] However, it is my understanding that this information is of limited use to FEI, and such information is available to interested parties at the customer's request.[16] If the converse proves to be true and pre-existing customer information does turn out to be valuable, the value will accrue to TES customers as well. That is, to deny FEI access to its own customer information generated in the gas utility business will be to reverse potential effiencies that would ultimately accrue to TES consumers. The above analysis would also apply if the data were in the form of customer lists or general knowledge of the market acquired by FEI employees in the course of gas utility business.

VI. THE ROLE OF COMPETITION IN NATURAL MONOPOLY INDUSTRIES

23. The evidence I have seen from the intervenors appears to implicitly assume that a competitive market outcome is always preferable to a regulated market outcome. In fact, cost-side synergies, such as those I have discussed above, can outweigh the presumed "benefits" from competitive firm entry. Suppose that there is a natural monopoly involving two product classes, say product A and B. Suppose also that Product B can function as a reasonably competitive industry. There is no guarantee that allowing or even encouraging entry of private unregulated firms into market B will enhance overall efficiency

24. It is possible that encouraging or allowing entry into market B could still be pro-competitive if competition confers some additional benefits, such as spurring innovation and the introduction of new products. [17] New entrants may bring with them innovative products and services, and compete with each other on the innovation margin in ways that are unlikely with a single monopoly incumbent. But it is incorrect to argue that just because a product

---

14 Exhibit C12-5, Written Evidence of Dr. Mark Jaccard (evidence submitted by Corix Utilities Inc.), at pp. 18-19.

15 Exhibit C1-5, Written Evidence of ESAC, at p. 35.

16 Exhibit B-2, Written Evidence of FortisBC Energy Utilities, at pp. 127-128.

17 Baumol, W.J. and R.D. Willig, "Fixed Costs, Sunk Costs, Entry Barriers, and Sustainability of Monopoly," The Quarterly Journal of Economics, Vol. 96, No. 3 (Aug., 1981), pp. 405-431

class can function as a competitive industry, then it is optimal to allow it to do so. There is a substantial literature on the sustainability of natural monopoly which highlights this regulatory dilemma. Although “free entry may encourage cost control and stimulate innovation,” it may also encourage firms “with neither new products nor improved technology to enter the industry.”[18] The potential effects of such entry are higher overall costs and a reduction in the average welfare of customers.

25. The evidence before the Commission describes two very different competitive landscapes.[19] On the one hand the evidence of some intervenors describe a robust competitive landscape in which competition in the TES market is largely unregulated, and suppliers compete on price as well as product design, quality and reliability dimensions.[20]

26. Alternatively, FEI has proposed that all producers of TES, including FEI, will typically be regulated. The implication, among other things, is that rates will be set by the regulator in order to recover costs and achieve a fair rate of return on the rate base. Thus, the competition between rival suppliers of TES projects will be a competition for the opportunity to serve a regulated market. While price competition will be relevant to determining the successful bidder, the winning bidder can only anticipate a regulated rate of return, which blunts incentives somewhat relative to an unregulated competitive market. But just as in an unregulated market, we should expect the outcome of bidding for TES projects to be that the project will be won by the low cost producer, which is of course the most desirable outcome from an efficiency perspective.

27. Other than price competition, important dimensions of competition will be on the margins of promised performance, reliability and innovative service offerings. Much of the competition will take place at the bidding and tender stage, where suppliers of TES projects will tender

---

18 Panzar, J.C. and R.D. Willig, “Free Entry and the Sustainability of Natural Monopoly,” *The Bell Journal of Economics*, Vol. 8, No. 1. (Spring, 1977), pp. 1-22.

19 Exhibit C12-6, Written Evidence of Corix Utilities Inc., at pp. 4-7 and Exhibit C1-5, Written Evidence of ESAC, at pp. 5-9.

20 “Unlike the large initial capital costs of the FEI natural gas utility … the TES market has no such barriers to entry. … The relatively small scale and locally-distinct nature of these systems make it possible for communities, developers, and individual customers to solicit competing bids for the provision of TES services. I understand that the present practice of TES developers is to actively compete against each other for projects, often through commercial tendering processes.” Exhibit C12-5, Written Evidence of Dr. Mark Jaccard (evidence submitted by Corix Utilities Inc.), at p. 12.

competing bids (e.g., for projects in hospitals, schools, commercial and residential construction projects). Economists have described such competition as competition "for the market" rather than competition "in the market." The distinction is that in the latter, more conventional case several firms compete in real time to sell products to a given consumer (e.g. the market for automobile purchases) whereas in the former case, the competition is at the bidding stage where firms compete for the right to construct a particular TES facility. Once the winner has been decided, customers will only be offered service by one producer, namely the firm chosen to supply that particular TES market. Of course, it is not essential that TES contracts are awarded as the outcome of a competitive bidding process. In some cases, customers will choose a sole source from a preferred supplier and in other cases they will encourage competitive tender offers. There is no reason to believe that the customer will not choose a process that best serves their interests in realizing a TES project.

28. In an unregulated competitive market, an incumbent who controls one market might have an incentive to cross-subsidize their products and services in another market in order to gain a competitive advantage over rival suppliers. Such an incentive is mitigated at the very least here for FEI where both the relevant product classes, the gas utility business and the TES market, will be regulated. This means that no matter what success was achieved in winning business through cross-subsidization, the outcome would be a regulated rate of return. Moreover, there is a further, perhaps more important, safeguard against cross-subsidization in that regular rate hearings for the FEI gas utility business would straightforwardly reveal the presence of any cross-subsidization of revenue generated from natural gas into FEI TES projects. These hearings entail extensive scrutiny of the FEI revenue requirement, and in my opinion the presence of cross-subsidization would be transparent.

29. I understand that ESAC in particular is contemplating non-regulated TES projects, and I have similarly been asked to assume that an exemption from regulation is possible. Assuming that there is an option for consumers between regulated and non-regulated TES they will consider the nature of regulation as a type of service offering along with other factors including price that I discuss above in paragraphs 26 and 27. If all TES projects are exempted or unregulated, then consumers will still undertake a similar analysis based on price and other considerations. Also, the safeguards that I address in paragraph 28 would be present regardless of the type or extent of regulation of TES since the natural gas class of service is regulated.

30. In summary, the appropriate framework of regulation can ensure that there will be fair competition between FEI and other suppliers offering products in the emerging TES market. Based on the evidence and my experience, I conclude that the intervenors concerns, although important, are likely to be unfounded as the TES market evolves. In particular any risk of cross-subsidization could be managed by the existing framework of regulatory oversight. The presence of FEI in the TES marketplace is most likely to introduce economic efficiencies that benefit the public without detriment to FEI's natural gas ratepayers.

(Original signed by)

Roger Ware, Ph.D.
January 18, 2012

Attachment 44.2

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Approximate Contract Termination Fee
Table 5- 0% Increase in volume
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Total Gross Plant in Service, Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
2	Accumulated Depreciation, Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
3	Net Salvage, Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
4	Deferral Account Repayment	Schedule 9, Line 37	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Add: Removal Costs[1]																					
6	Less: Excess Fueling Station Recoveries[2]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total	Sum of Line 1 to Line 6	1,829	1,725	1,628	1,531	1,433	1,330	1,222	1,127	1,032	937	843	748	653	558	464	369	274	179	85	(0)
8	**Net Termination Payment[3]**		**1,829**	**1,725**	**1,628**	**1,531**	**1,433**	**1,330**	**1,222**	**1,127**	**1,032**	**937**	**843**	**748**	**653**	**558**	**464**	**369**	**274**	**179**	**85**	**-**
9																						
10																						
11		O&M Rate	1.033	1.054	1.076	1.098	1.12	1.143	1.166	1.189	1.214	1.238	1.263	1.289	1.315	1.342	1.369	1.397	1.425	1.454	1.484	1.514
12		Capital Rate	1.815	1.851	1.888	1.926	1.964	2.003	2.044	1.9	1.872	1.834	1.791	1.743	1.691	1.636	1.578	1.519	1.458	1.395	1.332	1.243
13		Total Charge	**2.848**	**2.905**	**2.964**	**3.024**	**3.084**	**3.146**	**3.210**	**3.089**	**3.086**	**3.072**	**3.054**	**3.032**	**3.006**	**2.978**	**2.947**	**2.916**	**2.883**	**2.849**	**2.816**	**2.757**
14																						
15	Volume in Excess of Minimum Contract Demand		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17	1- Actual removal costs to be determined at time of contract termination and will be less the net salvage collected to date																					
18	2- Cumulative fueling station recoveries received from volumes in excess of minimum contract demand																					
19	3- Excess fueling station recoveries will be credited to a maximum amount of the net book value of the assets. That is, the net termination payment cannot be negative.																					

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Approximate Contract Termination Fee
Table 5- 25% increase in volume
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Total Gross Plant in Service, Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
2	Accumulated Depreciation, Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
3	Net Salvage, Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
4	Deferral Account Repayment	Schedule 9, Line 37	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Add: Removal Costs[1]																					
6	Less: Excess Fueling Station Recoveries[2]		(43)	(86)	(131)	(176)	(222)	(270)	(318)	(364)	(410)	(456)	(502)	(548)	(593)	(637)	(682)	(725)	(769)	(811)	(854)	(895)
7	Total	Sum of Line 1 to Line 6	1,787	1,639	1,497	1,355	1,210	1,061	904	763	622	481	340	200	60	(79)	(218)	(357)	(495)	(632)	(769)	(895)
8	**Net Termination Payment[3]**		**1,787**	**1,639**	**1,497**	**1,355**	**1,210**	**1,061**	**904**	**763**	**622**	**481**	**340**	**200**	**60**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9																						
10																						
11		O&M Rate	1.033	1.054	1.076	1.098	1.12	1.143	1.166	1.189	1.214	1.238	1.263	1.289	1.315	1.342	1.369	1.397	1.425	1.454	1.484	1.514
12		Capital Rate	1.815	1.851	1.888	1.926	1.964	2.003	2.044	1.9	1.872	1.834	1.791	1.743	1.691	1.636	1.578	1.519	1.458	1.395	1.332	1.243
13		Total Charge	**2.848**	**2.905**	**2.964**	**3.024**	**3.084**	**3.146**	**3.210**	**3.089**	**3.086**	**3.072**	**3.054**	**3.032**	**3.006**	**2.978**	**2.947**	**2.916**	**2.883**	**2.849**	**2.816**	**2.757**
14																						
15	Volume in Excess of Minimum Contract Demand		15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
16																						
17	1- Actual removal costs to be determined at time of contract termination and will be less the net salvage collected to date																					
18	2- Cumulative fueling station recoveries received from volumes in excess of minimum contract demand																					
19	3- Excess fueling station recoveries will be credited to a maximum amount of the net book value of the assets. That is, the net termination payment cannot be negative.																					

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Approximate Contract Termination Fee
Table 5- 50% increase in volume
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Total Gross Plant in Service, Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
2	Accumulated Depreciation, Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
3	Net Salvage, Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
4	Deferral Account Repayment	Schedule 9, Line 37	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Add: Removal Costs[1]																					
6	Less: Excess Fueling Station Recoveries[2]		(85)	(173)	(262)	(352)	(445)	(539)	(635)	(728)	(821)	(913)	(1,004)	(1,095)	(1,186)	(1,275)	(1,363)	(1,451)	(1,537)	(1,623)	(1,707)	(1,790)
7	Total	Sum of Line 1 to Line 6	1,744	1,553	1,366	1,179	988	791	586	399	211	25	(162)	(348)	(533)	(717)	(900)	(1,082)	(1,263)	(1,444)	(1,623)	(1,790)
8	**Net Termination Payment[3]**		**1,744**	**1,553**	**1,366**	**1,179**	**988**	**791**	**586**	**399**	**211**	**25**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9																						
10																						
11		O&M Rate	1.033	1.054	1.076	1.098	1.12	1.143	1.166	1.189	1.214	1.238	1.263	1.289	1.315	1.342	1.369	1.397	1.425	1.454	1.484	1.514
12		Capital Rate	1.815	1.851	1.888	1.926	1.964	2.003	2.044	1.9	1.872	1.834	1.791	1.743	1.691	1.636	1.578	1.519	1.458	1.395	1.332	1.243
13		Total Charge	**2.848**	**2.905**	**2.964**	**3.024**	**3.084**	**3.146**	**3.210**	**3.089**	**3.086**	**3.072**	**3.054**	**3.032**	**3.006**	**2.978**	**2.947**	**2.916**	**2.883**	**2.849**	**2.816**	**2.757**
14																						
15		Volume in Excess of Minimum Contract Demand	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
16																						
17	1- Actual removal costs to be determined at time of contract termination and will be less the net salvage collected to date																					
18	2- Cumulative fueling station recoveries received from volumes in excess of minimum contract demand																					
19	3- Excess fueling station recoveries will be credited to a maximum amount of the net book value of the assets. That is, the net termination payment cannot be negative.																					

Attachment 51.1

<u>Current Marketing Plans – Natural Gas for Transportation</u>

Purpose

FEI has an existing base of business delivering natural gas for transportation applications. This business is served under a variety of existing delivery tariffs including Rate Schedules, 6, 23, 25 and 16. Expansion of FEI's market share in the transportation market has been identified as a strategic priority for the company because the additional volumes generated within this market segment represent an opportunity to develop additional utilization of FEI's distribution system to the benefit of all customers.

This marketing plan outlines FEI's communication activities with respect to growing the NGT market in general. Fortis offers a variety of services to potential NGT customers including the following:

1. Commodity Supply (through FEI or through marketers)
2. Delivery of Natural Gas (CNG or LNG)
3. Fueling Station Services (CNG or LNG)

While FEI has the capability to supply an end-to-end service, customers may elect to secure service from others. For example customers may source commodity from marketers and may elect to purchase fueling services from others. This marketing plan is designed to encourage the use of NG for Transportation as an overall goal, regardless of whether FEI provides any specific element of the overall end-to-end service such as fueling services.

FEI has maintained a program to develop a market for NG in transportation applications for many years. A missing element in the BC market was the capability to provide a complete service including provision of fueling stations. FEI is now providing a fueling service to those customers that want it and expects that this change will increase the rate of adoption in the heavy duty market segment.

The goal of this marketing plan is to expand the use of natural gas for return-to-base fleet vehicles in the transportation sector B.C.by leveraging on direct and indirect effective communication channels. The plan will support the overall objective of growing market share in the transportation market hence the focus is not on provision of fueling station services.
By using natural gas instead of diesel or gasoline, a local business can save 25-40 per cent on fuel costs and see a 20-30 per cent reduction of GHG emissions. The transportation sector is the leading contributor to our province's GHG emissions, nearly 40 per cent, and is an area we can make significant reductions.

Communication strategies

The communications team will look to leverage opportunities to increase public awareness in an efficient manner, within current budget restrictions. In the first quarter, sales collateral materials will be developed for use in presentations and face-to-face meetings with potential clients. Using testimonials throughout the NGT materials will be a key strategy. The technology is used all over the world today, but it is still new to North America and hearing the words from someone who is using NG for transportation is stronger and more genuine than our best sales person. The NGT section on the FortisBC website will also see an overhaul in the first quarter to complement the sales collateral, and the use of earned media and social media will help drive traffic to the site.

Goals and Objectives

- *Obtain 173 HD vehicle additions, 166 TJ total NGT load, $14.6 M in 2012*
- *Generate awareness and understanding of*
  - the economic benefits of natural gas as a low-carbon transportation fuel among fleet operators, and
  - the economic and environmental benefits that natural gas vehicles can have for the province of B.C. among fleet owners, key stakeholders, and the public,

– *Generate awareness and understanding of*
    - The compression, storage, dispensing, transport and delivery services that FortisBC offers as part of their overall customer offering
    - Natural gas vehicle incentive programs (when available)

Market research

– *Please see research section of the NGV application*

– *Win-loss interviews conducted by a third party will continue in 2012 whenever a new customer is brought on*

Market Segments

Large, heavy-duty return-to-base fleets, primarily in the following sectors:

- Waste Haulers
- Transit Buses
- Class 8 Tractor Trailers
- Ferries

Target Audience

- *Primary A:* large volume shippers within the resource industries, such as mining
- *Primary B:* decision makers (fleet owners/operators) and influencers for large, heavy-duty return-to-base fleets
- *Secondary A:* provincial government. Support from the provincial and municipal government is extremely pertinent to the success of our NGV program.
- *Secondary B:* industry associations, such as the BC Trucking Association
- The general public (but is a remote audience)

Customer programs

- Currently there no FortisBC incentives available, but incentives may be available as early as May of 2012

Key messages – taken from Corporate Communications KM

- FortisBC is a forward-thinking organization committed to helping address B.C.'s climate action goals by providing innovative energy solutions such as natural gas for the transportation sector.
- Natural gas powered trucks are both economical and environmentally friendly. They provide a way to decrease lifecycle carbon emissions, reduce noise levels, and lower the cost of fuel.
- A compressed natural gas (CNG) powered refuse truck driven 45,000 kilometers per year in B.C. is estimated to produce about 15 fewer tonnes of carbon emissions annually.
- Natural gas is currently approximately 40 per cent less expensive than diesel fuel, so costs per kilometer can be reduced.
- Natural gas refuse trucks are quieter (more than 10 decibel difference at idle compared with diesel refuse trucks).
- Natural gas is the cleanest burning low-carbon fuel on the market today, leaving a smaller environmental footprint, helping to improve air quality and slowing climate change.
- As natural gas produces significantly fewer greenhouse gases (GHGs) than other carbon-based fuels like diesel and gasoline, heavy-duty NGVs emit 20 to 30 per cent less GHGs than their diesel counterparts.

- NGVs emit virtually no particulate matter, the harmful microscopic component of air pollution that penetrates deeply into the lungs.
- NGVs produce less nitrous oxide emissions (NOx), a key contributor to smog, reducing the need for costly NOx scrubbers and traps.
- Natural gas does not contain benzene, a common component of gasoline and a well-known carcinogen.
- As the cleanest alternative fuel available today, natural gas is popular in other jurisdictions as a transportation solution.
- Natural gas is a proven energy source for buses in jurisdictions with rigorous climate change regulations, such as California.
- More than 11,000 natural gas buses and 3,000 natural gas refuse haulers currently operate in the United States.
- One in four new buses sold in the United States are powered by natural gas.
- 95 per cent of Los Angeles' bus fleet runs on natural gas (more than 2,500 buses).

Budgeted Communication channel/Tactics

Activity	Date	By whom	Cost
Produce Sales Kit	Q1		
Information sheets CNG/LNG	March 10	JHS/CH	$500
Vedder Case Study	March 10	JHS/CH/CT	
Testimonials – Waste Management			$500
Trade Events	Q1-Q4		
Globe 2012	March 14-16	MG/CH	
Banner	March 9	JHS/CH	$500
Cuta Conference Victoria	May 26-30	MG/CH	
Details TBC			
Abbotsford Truxpo	Sept 20-22		
Booth space		MG/CH	
Banners/Booth	Sept 17	MG/CH/JHS	
Sales Kit (use existing)			
Promotion ADS of presence at events	August	JHS/CH	$5k
Web Upgrade or Video	Q2-Q4		
LNG/CNG	July 1	JHS/CH	$15k
Digital	Q1- Q4	MA/CH/JHS	
Enhanced web content	March 1	MA/CH	$0
Social Media plan	April 1	MA	
Associations	Q2 & Q4		
Coop advertising opportunities	April 1	JHS/CH	$5k
Potential Media Buy (Q2-Q4)	Q2-Q4		
Wasserman to identify & recommend publication & advertising channels that reach the target audience.	April 1	JHS/AW/WM	
Media Planet buy – transportation issues	Q2	JHS/AW/CH	$30K

News Releases Release schedule Photo opportunities Vedder/KSD Application/Fuel stations Media around event participation	Q1-Q4	KW	$0
Leveraging on bill insert opportunities Rate 3 – shared with RNG Rate 2 – with EEC programs Rate 3 – e-newsletter	 Q2 Q3 Q2	 JHS/CH	 $2k $2k $0
Total Estimate communications outreach 2012			**$60.5k**

Attachment 51.4

Tel: 778-578-3831
Fax: 604.592.7522
www.fortisbc.com

MEMO

To	All Employees	Date	February 22, 2012
	Expression of Interest	From	Susan Chiu
Re	Business Development Manager	CC	BCE-73/2012

The focus of this position is to grow FortisBC's rate base and revenues by pursuing profitable new business opportunities. Investments will be achieved through the identification and evaluation of potential projects and the successful strategic negotiations of commercial terms and arrangements resulting in contracts and subsequent investment. The key success measures are developing and concluding contracts and projects that allow FortisBC to invest in assets that provide benefit to its customers and earn a rate of return for the shareholders.

Key Responsibilities

- Identify market opportunities based on their alignment with FortisBC's strategic objectives
- Develop plans to move proposed projects from the idea phase through to implementation
- Coordinate financial analysis of project initiatives and develop supporting business case
- Participate in commercial negotiations with customers, partners, suppliers, or stakeholders
- Support regulatory process for project approvals
- Develop relationships with Industry stakeholders, government and other utilities
- Maintain awareness of all activities that affect business development potential and to advise senior management on strategic issues.

Required Qualifications

- Completion of a post-secondary degree in a relevant field such as Business Administration, Commerce or Engineering.
- 5 – 10 years related work experience.
- Strong skills in the use of financial evaluation methods and in project development
- Knowledge of utility regulatory principles
- Familiarity with gas pipeline infrastructure and market participants
- Ability to develop and maintain collaborative relationships including demonstrated effectiveness seeking input from stakeholders and communicating and negotiating with customers and public groups.
- Demonstrated ability to think strategically and understand and apply business analysis methods;
- Corporately focused with the ability to align projects with business goals;
- Ability to use technology to achieve departmental targets;
- Combines a results-oriented focus with a capacity to manage ambiguity and change;
- Must be capable of high levels of initiative and judgment;

- Must be capable of strong project manager skills, and is well organized with ability to plan and execute projects on time;
- Works effectively in a team-oriented environment.

Preferred Experience, Skills & Knowledge (Above the minimum requirements)

- Prior experience in negotiating agreements in a regulated company.

If you have what it takes to be successful in this role, please respond by submitting the On-line Employee Application (Internal Application) form # 1074. Click here for the link to the form. Include a covering letter and resume outlining how you meet the position requirements to Talent Sourcing, Human Resources, Surrey Ops 1 **by March 6, 2012 – 4:30 PM.**

FORTIS BC™

Management and Exempt Job Description

Title: Manager, Energy Products and Services
Division: Gas
Business Area: Energy Solutions and External Relations
Department: Market and Business Development

Job Summary:

Working in accordance with the organization's strategic vision, core values and leadership competencies, reporting to the Director, Resource Planning and Market Development this position is responsible to provide leadership in the effective management and execution of technical product support for traditional and non-traditional energy marketing programs.

Key Accountabilities:

Provide leadership in the effective management and execution of technical support for marketing program development including product and service lines such as NGV, Bio-gas, Solar Thermal, Combined Heat & Power, Pilot Studies, Codes Standards, Innovative Technologies and support services for Demand Side Management program development. Participate in the development and implementation of customer growth and retention strategies for residential, commercial and industrial market segments and provide technical support for traditional and non-traditional alternate energy applications and related products.

Provide leadership to staff; effectively utilize team members and help execute career development plans. Coordinate internal and external resources required to deliver successful results; ensure key deliverables are defined and assign responsibilities with planned outcomes. Support other departments in the development of processes to enable proper program delivery; resolve and/or escalates issues. Provide high level project management of asset construction and ongoing operation and maintenance.

Establish and maintain effective relationships with stakeholders; provide information, monitors systems integration activities, negotiates deviations in plans and coordinates resources. Liaise with customers, marketers and others; maintain awareness of activities impacting business development potential, customer relationships and energy technological advancements. Assess feedback from customers, municipalities, regulators and other stakeholders to ensure internal business processes are responsive to customer need.

Leads energy feasibility proposal efforts, including project scoping; work with project partners throughout the program design, implementation, management and close-out process and interface with program funders and clients; ensure work complies with engineering standards, codes, specifications, and safety design instructions. Develop and maintain budgets; monitor expenses.

Qualifications:

Education and Experience:

Bachelor's degree in a related discipline from a recognized program plus Eight (8) years of technical management experience in energy product market development within an Utility environment including project management, operations and maintenance experience or an equivalent combination of education, training and experience.

Management and Exempt Job Description

Title: Manager, Energy Products and Services
Division: Gas
Business Area: Energy Solutions and External Relations
Department: Market and Business Development

Knowledge, Skills and Abilities:

Knowledge of NGV commercial and industrial market segments in BC, LNG station design and operation
Knowledge of Energy related Codes and Standards, single and three phase electrical systems, Building Science and EnerGuide rating systems, building energy performance monitoring and metering systems, Bio-gas systems, Solar Energy systems
Business Development and Customer Relationship skills
Demonstrated ability to facilitate team and client meetings effectively
Demonstrated ability to work well independently and in a team setting
Demonstrated ability to develop, document and implement strategies
Demonstrated ability to seek out opportunities to increase customer satisfaction and deepen client relationships
Demonstrated ability to communicate effectively with clients identifying needs and evaluating alternative energy solutions
Demonstrated ability to educate other innovators and clients through both formal and informal training programs
Demonstrated ability to independently leverage critical thinking skills to address real-world issues
Demonstrated ability to prioritize and multitask on a wide range of competing demands with attention to detail
Demonstrated ability to communicate effectively both verbally and in writing
Demonstrated ability to adapt communication of complex technical processes to a verity of audiences
Demonstrated ability to work across cultural and organizational boundaries, and operate successfully in an intense business environment maintaining effective working relationships
Demonstrated ability to manage the process of innovative change effectively

Additional Information (for Recruiting Purposes Only):

Integrated Leadership Competencies:	Core Values:
Drive for Results *Lead High Performance* *Drive and Implement Prudent Change* *Make Optimal Decisions* *Build Working Relationships*	*Safety First* *Respect, Integrity, Open Communication* *Teamwork* *Action Oriented, Results Focused* *Continuous Learning & Innovation* *Reward Performance and Excellence*

Approval:

Name	Title	Date
David A. Bennett	*Dir, Resource Plan'g & Mkt Dev*	*November 3, 2011*

Project Manager

Position Overview

The Project Manager provides project management services to the company's Asset Managers and others. In addition to superior project management skills, the Project Manager will have a sound technical knowledge of the: Oil and Gas; Petrochemical; Alternative Energy industry with a broad background of experience in the areas of: risk management; contract management; resource management and change management.

Responsibilities

Primarily responsible for the safe and successful execution of a variety of assigned projects to agreed: scope; schedule, cost and quality

- Accountable for the project: schedule; budget; contingency plans; exception controls; resource management; risk management; reporting; contract management; procurement; legal; environmental management; stakeholder communications and customer satisfaction
- Provides project management for a variety of projects and requests, primarily related to capital asset installations and upgrades including: pipelines; compression and pressure regulating facilities; line heaters; LNG facilities; propane facilities; district energy systems and electrical and control systems
- Leads cross functional teams, as required, to successfully deliver projects in accordance with FortisBC's project management process
- Provides leadership in the areas of construction safety and environment
- Performs: assessments; economic feasibility and risk studies using practical experience and technical knowledge
- Identifies and manages any risks associated with the successful delivery of projects
- Reviews the design, including: mechanical; civil; electrical and instrumentation, of new facilities and upgrades to existing facilities
- Analyzes costs, schedule and performance of options in order to make recommendations to internal clients as to the preferred alternatives
- Works without direction but adheres to FortisBC's project management process
- Directs the work of teams including: engineers; technologists; external consultants and contractors as required.

Requirements

Essential Industry Experience

- 5 years minimum experience in Construction Management
- 5 years minimum experience in Project Management

Qualifications

- Professional Engineer, or equivalent education and relevant industry experience
- Project Management Professional (PMP) would be an asset

Essential Skills

- Strong project management skills with proven successful track record of project delivery
- Strong interpersonal skills and the proven ability to provide leadership to a team and to work in a team environment
- Strong organizational skills with a demonstrated ability to coordinate work plans and forecast, plan and schedule project resource requirements
- Excellent communication skills - written and oral
- Demonstrated ability to develop collaborative relationships
- Strong negotiation and conflict resolution skills
- Strong problem solver, with keen analytical skills and the ability to implement solutions with win-win outcomes.

ROLE DESCRIPTION

Title: Natural Gas Vehicles Account Manager	Job Code

Role Summary: Reporting to the Sales Manager, this position is responsible to participate in the implementation sales program activities and account management goals and growth strategies for the Natural Gas Vehicle (NGV) sales market. Actively solicit the sale of gas compression equipment in the designated service territory and execute opportunities to add to rate base through the sale and installation of compression equipment or LNG infrastructure. Prepare economic tests to determine viability of compression services. Manage relationships with current NGV accounts; establish and maintain regular contact with customers, compression equipment and vehicle conversion and OEM suppliers and other equipment vendors. Maintain relationships with various groups and associations to foster ideas and opportunities for capturing natural gas vehicle loads. Work with various representatives from municipal governments or organizations to influence codes and procedures to favour safe and competitive natural gas vehicle installations. Ensure the installation of compressor meets customer's expectations.

Key Accountabilities:

Participate in the implementation of sales program activities and account management goals and growth strategies for the Natural Gas Vehicle (NGV) sales market; actively solicits the sale of gas compression equipment in the designated service territory and executes opportunities to add to rate base through the sale and installation of compression equipment or LNG infrastructure. Prepares economic tests; determines viability of compression services.

Manages relationships with current NGV accounts; establishes and maintains regular contact with customers, compression equipment and vehicle conversion and OEM suppliers and other equipment vendors. Maintains relationships with various groups and associations to foster ideas and opportunities for capturing natural gas vehicle loads.

Works with various representatives from municipal governments or organizations to influence codes and procedures to favour safe and competitive natural gas vehicle installations. Maintains current on information related to current technological advances and constraints for NGV applications.

Ensures the installation of compressor meets customer's expectations; liaises with various departments regarding the effective provisioning of sales contracts and related services. Participates in trades shows; monitors and maintains expenses.

Qualifications:

Education and Experience:

Bachelors Degree in Marketing, Business or Commerce or equivalent from a recognized program plus Five (5) years recent, related, professional sales and marketing experience experience in the gas industry or an equivalent combination of education, training and experience. Valid BC Drivers License.

Role Specific Knowledge, Skills and Abilities:

Knowledge of energy market place natural gas vs. gasoline or diesel
Knowledge of NGV equipment (vehicle and compression equipment)
Demonstrated sales and customer account/relationship management skills
Ability to communicate effectively both verbally and in writing.
Ability to prepare and present information, motivate and influence others
Ability to research and document relevant topics for potential customers
Ability to establish strong working relationships with all levels of the organization.

Vitto Triggiano	*September 30, 2009*
Signature	***Date***

The duties and responsibilities above reflect information considered necessary to describe the general purpose and/or general function of this role and should not be construed as a detailed description of all responsibilities.

Attachment 55.1

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Revenue Requirement
Appendix D - Schedule 1
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Revenue Requirement**																					
2	Cost of Energy Sold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	Schedule 2, Line 19	50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
4	Property Taxes	Schedule 2, Line 29	17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
5	Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
6	Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
7	Amortization Expense	Schedule 9, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	Schedule 2, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	Schedule 3, Line 20	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
10	Earned Return	Schedule 5, Line 27	142	138	130	123	115	108	100	93	85	78	70	63	55	48	40	33	25	18	10	3
11																						
12	**Annual Revenue Requirement**	Sum of Lines 2 through 10	**307**	**261**	**274**	**280**	**285**	**287**	**287**	**286**	**283**	**280**	**276**	**271**	**267**	**261**	**256**	**250**	**244**	**238**	**232**	**222**

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): O&M, Other Revenue and Property Tax
Appendix D - Schedule 2
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross O&M**																					
2	Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																						
4	Vehicle Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Employee Expenses		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Materials & Supplies		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Computer Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Fees & Administrations Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contractor Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
10	Facilities		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Recoveries & Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Non-Labour Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
14																						
15	Total Gross O&M Expenses		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
16																						
17	(Less): Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Add (Less): Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
20																						
21	**Other Revenue**																					
22	Environmental Credits		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Property Taxes**																					
27	General, School and Other		17	18	18	18	19	19	19	20	20	21	21	22	22	22	23	23	24	24	25	25
28	1% in Lieu of General Municipal Tax[1]	Schedule 11, Line 36/1000 x 1%	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
29	Total Property Taxes		17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
30																						
31	1- Calculation is based on the second preceeding year; ex., 2012 is based on 2010 revenue																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Income Tax Expense
Appendix D - Schedule 3
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Income Tax Expense**																					
2																						
3	Earned Return	Schedule 5, Line 27	142	138	130	123	115	108	100	93	85	78	70	63	55	48	40	33	25	18	10	3
4	Deduct: Interest on debt	Schedule 5, Line 26	(74)	(72)	(68)	(64)	(60)	(56)	(52)	(48)	(44)	(40)	(37)	(33)	(29)	(25)	(21)	(17)	(13)	(9)	(5)	(2)
5	Add (Deduct): Amortization Expense	Schedule 9, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
7	Add: Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	Deduct: Overhead Capitalized Expensed for Tax Purposes		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct Removal Costs	Schedule 8, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
10	Deduct: Capital Cost Allowance	Schedule 4, Line 29	(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
11	Taxable Income After Tax	Sum of Lines 3 through 10	8	(120)	(71)	(33)	(2)	22	40	55	65	74	79	84	86	88	88	88	88	86	85	73
12																						
13	Income Tax Rate		25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
14	1 - Current Income Tax Rate	1 - Line 13	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
15																						
16	Taxable Income	Line 11 / Line 14	11	(160)	(95)	(43)	(3)	29	54	73	87	98	106	111	115	117	118	118	117	115	113	98
17																						
18	Total Income Tax Expense	Line 16 x Line 13	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
19	Adjustments		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Net Tax Expense	Line 18 + Line 19	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
21																						
22	Loss Carry-forward	Loss Carry-forward doesn't apply																				
23	Opening Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Loss Carry-forward		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Loss Utilization		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Closing Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Capital Cost Allowance
Appendix D - Schedule 4
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**CNG Dispensing Equipment- Class 8 @ 20%**																					
2	Opening Balance	Preceeding Year, Line 5	-	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22
3	Additions	Schedule 7 , Line 11 - AFUDC	1,376	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(138)	(248)	(198)	(158)	(127)	(101)	(81)	(65)	(52)	(42)	(33)	(27)	(21)	(17)	(14)	(11)	(9)	(7)	(6)	(4)
5	Closing Balance	Sum of Lines 2 through 4	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22	18
6																						
7	**Foundation- Class 1.3 @ 6%**																					
8	Opening Balance	Preceeding Year, Line 11	-	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141
9	Additions	Schedule 7 , Line 12 - AFUDC	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(13)	(26)	(24)	(23)	(21)	(20)	(19)	(18)	(17)	(16)	(15)	(14)	(13)	(12)	(12)	(11)	(10)	(10)	(9)	(8)
11	Closing Balance	Sum of Lines 8 through 10	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141	132
12																						
13	**NG Dehydrator- Class 8 @ 20%**																					
14	Opening Balance	Preceeding Year, Line 17	-	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1
15	Additions	Schedule 7 , Line 13 - AFUDC	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(4)	(8)	(6)	(5)	(4)	(3)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
17	Closing Balance	Sum of Lines 14 through 16	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1	1
18																						
19																						
20	**Capitalized Overhead- Class 0 @ 0%**																					
21	Opening Balance	Preceeding Year, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Additions	Schedule 2 , Line 17 x 0 / 0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	CCA	[Line 21 + (Line 22 x 1/2)] x CCA Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Closing Balance	Sum of Lines 21 through 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Total CCA**																					
27	Opening Balance	Preceeding Year, Line 30	-	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164
28	Additions	[1]	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	CCA		(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
30	Closing Balance	Sum of Lines 27 through 29	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164	151
31																						
32	1- Schedule 7 , Line 19 - Line 18, + Line 22 above - AFUDC																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Rate Base
Appendix D - Schedule 5
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Rate Base**																					
2	Gross Plant In Service- Beginning	Schedule 7, Line 10	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
3	Gross Plant In Service- Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
4																						
5	Accumulated Depreciation- Beginning	Schedule 8, Line 10	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
6	Accumulated Depreciation- Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
7																						
8	Contributions in Aid of Construction- Beginning	Schedule 7, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contributions in Aid of Construction- Ending	Schedule 7, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10																						
11	Negative Salvage - Beginning	Schedule 8, Line 53	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
12	Negative Salvage - Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
13																						
14	Accumulated Amortization- Beginning	Schedule 8, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	Schedule 8, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17	Net Plant in Service, Mid-Year	Sum (Lines 2 through 15)/2	895	1,743	1,648	1,553	1,459	1,364	1,269	1,174	1,080	985	890	795	700	606	511	416	321	227	132	42
18																						
19	Adjustment to 13-month average	[1]	900	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	Schedule 9, Line 58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	[2]	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
22	**Total Rate Base**	**Sum of Lines 17 through 21**	**1,792**	**1,739**	**1,644**	**1,550**	**1,455**	**1,360**	**1,265**	**1,171**	**1,076**	**981**	**886**	**791**	**697**	**602**	**507**	**412**	**318**	**223**	**128**	**38**
23																						
24	**Return on Rate Base**																					
25	Equity Return	Line 22 x ROE x Equity %	68	66	62	59	55	52	48	44	41	37	34	30	26	23	19	16	12	8	5	1
26	Debt Component	[3]	74	72	68	64	60	56	52	48	44	40	37	33	29	25	21	17	13	9	5	2
27	Total Earned Return	Line 25 + Line 26	**142**	**138**	**130**	**123**	**115**	**108**	**100**	**93**	**85**	**78**	**70**	**63**	**55**	**48**	**40**	**33**	**25**	**18**	**10**	**3**
28	Return on Rate Base %	Line 27 / Line 22	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
29																						

30 1- [Schedule 7, (Line 19 + Line 42) + Schedule 8, (Line 19+ Line 42)] x (Days In-service/365-1/2)
31 2- Schedule 7, Line 37 x FEI CWC/Closing GPIS %
32 3- Line 22 x (LTD Rate x LTD% + STD Rate x STD %)

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Capital Spending
Appendix D - Schedule 6
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Capital Spending Prior to 2012																					
2	CNG Dispensing Equipment		1,376																			
3	Foundation		442																			
4	NG Dehydrator		43																			
5	Total Capital Spending Prior to 2012	Sum of Lines 2 through 4	1,861																			
6																						
7	AFUDC Prior to 2012																					
8	CNG Dispensing Equipment		24																			
9	Foundation		-																			
10	NG Dehydrator		1																			
11	Total AFUDC Prior to 2012	Sum of Lines 8 through 10	25																			
12																						
13	Capital Spending 2012 Onwards																					
14	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Capital Spending 2012 Onwards	Sum of Lines 14 through 16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																						
19	AFUDC 2012 Onwards																					
20	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total AFUDC 2012 Onwards	Sum of Lines 20 through 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																						
25	Total Capital Spending[1]	Line 5 + Line 17	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total AFUDC	Line 11 + Line 23	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Total Annual Capital Spending and AFUDC	Line 25 + Line 26	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28																						
29	Contributions in Aid of Construction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
31	Net Annual Project Costs- Capital	Line 27 + Line 29 + Line 30	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
32																						
33	Total Project Costs- Capital Spending and AFUDC	Sum of Line 27	**1,885**																			
34	Total Net Project Costs- including CIAC & Removal Costs	Sum of Line 31	**1,895**																			
35																						
36	1- Excluding capitalized overhead; First year of analysis includes all prior year spending																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Gross Plant in Service & Contributions in Aid of Construction
Appendix D - Schedule 7
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross Plant in Service**																					
2																						
3	Gross Plant in Service, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
5	Foundation	Preceeding Year, Line 32	-	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
6	NG Dehydrator	Preceeding Year, Line 33	-	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 9	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
11																						
12	Gross Plant in Service, Additions																					
13	CNG Dispensing Equipment	Schedule 6, Lines 2 + 8 + 14 + 20	1,400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Foundation	Schedule 6, Lines 3 + 9 + 15 + 21	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	NG Dehydrator	Schedule 6, Lines 4 + 10 + 16 + 22	44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17																						
18	Capitalized Overhead	Schedule 2, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Gross Plant in Service, Additions	Sum of Lines 13 through 18	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																						
21	Gross Plant in Service, Retirements																					
22	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Gross Plant in Service, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Gross Plant in Service, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
32	Foundation	Line 5 + Line 14 + Line 23	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
33	NG Dehydrator	Line 6 + Line 15 + Line 24	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Gross Plant in Service, Ending	Sum of Lines 31 through 36	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
38																						
39																						
40	**Contributions in Aid of Construction (CIAC)**																					
41	CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Accumulated Depreciation & Amortization
Appendix D - Schedule 8
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Accumulated Depreciation**																					
2																						
3	Accumulated Depreciation, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)
5	Foundation	Preceeding Year, Line 32	-	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)
6	NG Dehydrator	Preceeding Year, Line 33	-	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 9	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
11																						
12	Accumulated Depreciation, Depreciation Expense[1]																					
13	CNG Dispensing Equipment@ 5%	Schedule 7, Line 4 & Line 13	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
14	Foundation@ 5%	Schedule 7, Line 5 & Line 14	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
15	NG Dehydrator@ 5%	Schedule 7, Line 6 & Line 15	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
16																						
17																						
18	Capitalized Overhead@ 0%	Schedule 7, Line 9 & Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Accumulated Depreciation, Depreciation Expe	Sum of Lines 13 through 18	(95)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)
20																						
21	Accumulated Depreciation, Retirements																					
22	CNG Dispensing Equipment	Schedule 7, Line 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation	Schedule 7, Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator	Schedule 7, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead	Schedule 7, Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Accumulated Depreciation, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Accumulated Depreciation, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)	(1,400)
32	Foundation	Line 5 + Line 14 + Line 23	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)	(442)
33	NG Dehydrator	Line 6 + Line 15 + Line 24	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)	(44)
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Accumulated Depreciation, Ending	Sum of Lines 31 through 36	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
38																						
39																						
40	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**																					
41	Accumulated Amortization CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Amortization	[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Accumulated Amortization CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45																						
46	**Removal Cost Provision**																					
47	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Foundation	-Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
49	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Total Removal Cost Provision	Sum of Lines 47 through 49	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
51																						
52	**Negative Salvage Continuity - Foundation**																					
53	Opening Balance	Preceeding Year, Line 56	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
54	Provision (Cr.) [2]	Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
55	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
56	Ending Balance	Sum of Lines 53 through 55	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
57																						
58	1- Depreciation & Amortization Expense calculation is based on opening balance + (additions x in-service days/365 if it is the in-service year for project/; otherwise, additions x 1/2)																					
59	2- Annual Salvage Rate calculation is 0.11% based on (foundation costs / removal costs / retirement years																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Deferred Charges & Deficiency / Surplus [Tracker]
Appendix D - Schedule 9
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	*Deferred Charge- O&M*																					
2	Opening Balance	Previous Year, Line 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	Line 3 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	(Lines 2 + 3 + 4) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	Sum of Lines 3 through 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Closing Balance	Lines 2 + 6 + 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																						
10	*Deferred Charge- Property Tax*																					
11	Opening Balance	Previous Year, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	Line 12 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	(Lines 11 + 12 + 13) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	Sum of Lines 12 through 14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	Lines 11 + 15 + 16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																						
19	*Deferred Charge- (Gain)/Loss on Asset Disposal*																					
20	Opening Balance	Previous Year, Line 26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Tax	Line 21 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	AFUDC	(Lines 20 + 21 + 22) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Net Additions	Sum of Lines 21 through 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Amortization Expense @ years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Closing Balance	Lines 20 + 24 + 25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27																						
28	**Deficiency / Surplus [Tracker]**																					
29	Opening Balance	Previous Year, Line 37	-	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gross Addition	Schedule 11, Line 21	39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Net Addition	Line 30 + Line 31	39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
33	AFUDC																					
34	Equity	(Line 29) x (Schedule 10, Lines 8 x 9)	-	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Debt	[1]	-	1	1	1	1	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Interest Adjustment	[2]	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Closing Balance	Sum of Lines 32 through 36	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38																						
39	**Deferred Charge- Non Rate Base**																					
40	Opening Balance	Previous Year, Line 47	-	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Opening Balance, Adjustment	Opening balance transfer to rate base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Gross Additions		39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	AFUDC		-	3	2	2	2	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
45	Net Additions	Sum of Lines 42 through 44	39	(9)	(3)	(2)	(4)	(8)	(14)	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Closing Balance	Lines 40 + 41 + 45 + 46	39	30	27	25	22	14	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-
48																						
49	**Deferred Charge- Rate Base**																					
50	Opening Balance	Previous Year, Line 57	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Closing Balance	Line 50 + Line 54 + Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57																						
58	Deferred Charge, Mid-Year	(Line 50+ Line 51 + Line 56) / 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59																						
60	1- (Line 29) x [Schedule 10 , (Lines 11 x 12+ Lines 13 x 14) x (1- Tax Rate)]																					
61	2- Adjustment to net account to zero in final year; result of varying WACC rates throughout contract																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Present Value of Revenue Requirement
Appendix D - Schedule 10
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1																						
2	Annual Revenue Requirement (Excluding O&M)	Schedule 1, Line 12 -Line 3	257.0	210.2	221.5	227.3	230.4	231.2	230.3	228.0	224.6	220.0	214.9	209.1	202.9	196.3	189.4	182.2	174.9	167.4	159.8	149.2
3	Annual Number of Customers		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	Annual Revenue Requirement (O&M)	Schedule 1, Line 3	50.0	51.0	52.1	53.1	54.2	55.3	56.4	57.6	58.7	59.9	61.1	62.4	63.6	64.9	66.2	67.6	69.0	70.4	71.8	73.2
5																						
6	**Annual Discount Rate**																					
7	Equity Component																					
8	ROE %		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
9	Equity Portion		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
10	Debt Component																					
11	Long Term Debt Rate		6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%
12	Long Term Debt Portion		58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%
13	Short Term Debt Rate		4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
14	Short Term Debt Portion		1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%
15																						
16	Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Pre- Tax Weighted Average Cost of Capital (WACC)[1]		9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
18	After- Tax Weighted Average Cost of Capital (WACC)[2]		6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
19																						
20	**Present Value of Revenue Requirement**																					
21	PV of Annual Cost of Service (excl O&M) Revenue Requirement	Line 2 / (1 + Line 18)^Yr	240.4	183.9	181.4	174.1	165.1	155.0	144.4	133.8	123.2	112.9	103.2	93.9	85.3	77.2	69.7	62.7	56.3	50.4	45.0	39.3
22	PV of Annual Revenue Requirement ($/Mnth)		20	15	15	15	14	13	12	11	10	9	9	8	7	6	6	5	5	4	4	3
23	Total PV of Cost of Service (excl O&M)	Sum of Line 21	2,297.3																			
24	Total PV of Cost of Service (excl O&M) over contract term		1,244.3																			
25	PV of Annual O&M	Line 4 / (1 + Line 18)^Yr	46.8	44.6	42.6	40.7	38.8	37.1	35.4	33.8	32.2	30.8	29.4	28.0	26.7	25.5	24.4	23.3	22.2	21.2	20.2	19.3
26	Total PV of O&M	Sum of Line 25	622.9																			
27	Total PV of O&M over contract term		286.0																			
28																						
29	PV of Annual Customers	Line 3 / (1 + Line 18)^Yr	0.9	0.9	0.8	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
30	Total PV of Customers	Sum of Line 29	10.6																			
31																						
32																						
33	**Tariff Analysis**																					
34	Annual Volume (TJ)		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
35																						
36	**Cost of Service (excluding O&M)**																					
37	Annual Cost of Service per Customer ($/Yr)	Line 2 x 1000 / Line 3	256,987	210,177	221,539	227,338	230,393	231,250	230,346	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
38	Monthly Cost of Service per Customer ($/Mnth)	Line 37 / 12	21,416	17,515	18,462	18,945	19,199	19,271	19,196	19,003	18,716	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
39	Annual Volumetric Cost of Service ($/GJ)	Line 2 / Line 34	2.570	2.102	2.215	2.273	2.304	2.312	2.303	2.280	2.246	2.200	2.149	2.091	2.029	1.963	1.894	1.822	1.749	1.674	1.598	1.492
40																						
41	**O&M**																					
42	Annual Cost of Service per Customer ($/Yr)	Line 4 x 1000 / Line 3	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
43	Monthly Cost of Service per Customer ($/Mnth)	Line 42 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
44	Annual Volumetric Cost of Service ($/GJ)	Line 4 / Line 34	0.500	0.510	0.521	0.531	0.542	0.553	0.564	0.576	0.587	0.599	0.611	0.624	0.636	0.649	0.662	0.676	0.690	0.704	0.718	0.732
45																						
46	**Levelized Tariff Analysis**																					
47	PV of Annual Volume (TJ)	Line 34 / (1 + Line 18)^Yr	93.5	87.5	81.9	76.6	71.6	67.0	62.7	58.7	54.9	51.3	48.0	44.9	42.0	39.3	36.8	34.4	32.2	30.1	28.2	26.4
48	Total PV of Volume (TJ)	Sum of Line 47	1,068.1																			
49																						
50	Levelized Annual Delivery Charge per Customer ($/Yr)	Line 23 x 1000 / Line 30	**274,315**																			
51	Levelized Monthly Delivery Charge per Customer ($/Mnth)	Line 50 / 12	**22,860**																			
52	Levelized Volumetric Delivery Rate ($/GJ)	(Line 23 + Line 26) / Line 48	**2.734**																			
53																						
54	1- (Line 8 x Line 9) / 1- Line 16 + (Line 11 x Line 12 + Line 13 x Line 14)																					
55	2- Line 9 x Line 10 + [(Line 12 x Line 13 + Line 14 x Line 15) x 1- Line 17]																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Contract Rate Design
Appendix D - Schedule 11
($), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cost of Service (Excluding O&M)**																					
2	Required Delivery Revenue ($) (discounted) - 20 years	Schedule 10, Line 23 x 1000	2,297,264																			
3	Required Delivery Revenue ($) (discounted, contract term) - 7 yrs	Schedule 10, Line 24 x 1000	1,244,340																			
4	Flat Rate for 20 Years		274,315																			
5																						
6	Year 1 Contract Rate, Escalated at 2% Annually	[1]	217,755																			
7	Annual Contract Rate Escalation		2.00%																			
8																						
9	Annual Discount Rate (After- Tax WACC)	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
10	Annual Contract Rate	[2]	217,755	222,111	226,553	231,084	235,706	240,420	245,228	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
11	PV of Annual Contract Rate	Line 10 / (1 + Line 9)^Yr	203,709	194,380	185,478	176,984	168,879	161,145	153,765	133,760	123,243	112,948	103,185	93,946	85,272	77,176	69,658	62,706	56,298	50,408	45,010	39,315
12	Cumulative Revenue		439,866	222,111	666,419	897,503	1,133,208	1,373,628	1,618,856	1,846,888	2,071,478	2,291,500	2,506,365	2,715,480	2,918,375	3,114,669	3,304,058	3,486,300	3,661,200	3,828,603	3,988,384	4,137,570
13	PV of Cumulative Revenue		398,089	194,380	379,858	556,842	725,721	886,866	1,040,631	1,174,391	1,297,634	1,410,581	1,513,767	1,607,713	1,692,985	1,770,161	1,839,819	1,902,525	1,958,823	2,009,231	2,054,241	2,093,555
14	PV of Revenue Collected	Sum of Line 11	2,297,264																			
15																						
16																						
17	Monthly Rate, Escalated at 2% annually and then COS based beyond Contract Term		18,146	18,509	18,879	19,257	19,642	20,035	20,436	19,003	18,716	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
18	Annual Volumetric Contract Rate ($/GJ)	Line 10 / Line 30 / 1000	**2.178**	**2.221**	**2.266**	**2.311**	**2.357**	**2.404**	**2.452**	**2.280**	**2.246**	**2.200**	**2.149**	**2.091**	**2.029**	**1.963**	**1.894**	**1.822**	**1.749**	**1.674**	**1.598**	**1.492**
19																						
20	Annual Cost of Service (excl O&M)	Schedule 10, Line 2 x 1000	256,987	210,177	221,539	227,338	230,393	231,250	230,346	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
21	Annual Difference (Cost of Service - Contract Rate)	Line 20 - Line 10	39,231	(11,933)	(5,014)	(3,746)	(5,313)	(9,170)	(14,882)	-	-	-	-	-	-	-	-	-	-	-	-	-
22																						
23	**Cost of Service (O&M)**																					
24	Forecast Annual BC CPI Rate	CPI BC Stats Canada	1.99%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%
25	Annual O&M Expense	Schedule 1, Line 3 x 1000	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
26																						
27	Monthly Rate, Escalated at CPI annually	Line 25 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
28	Annual O&M Volumetric Contract Rate ($/GJ)	Line 25 / Line 30 / 1000	**0.500**	**0.510**	**0.521**	**0.531**	**0.542**	**0.553**	**0.564**	**0.576**	**0.587**	**0.599**	**0.611**	**0.624**	**0.636**	**0.649**	**0.662**	**0.676**	**0.690**	**0.704**	**0.718**	**0.732**
29																						
30	Annual Volume (TJ)	Minimum contract demand	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
31																						
32	Cost of Service (excl O&M) Volumetric Contract Rate ($/GJ)	Line 18	2.178	2.221	2.266	2.311	2.357	2.404	2.452	2.280	2.246	2.200	2.149	2.091	2.029	1.963	1.894	1.822	1.749	1.674	1.598	1.492
33	O&M Volumetric Contract Rate ($/GJ)	Line 28	0.500	0.510	0.521	0.531	0.542	0.553	0.564	0.576	0.587	0.599	0.611	0.624	0.636	0.649	0.662	0.676	0.690	0.704	0.718	0.732
34	Annual Overhead Allocation Charge ($/GJ)	[3]	0.200	0.204	0.208	0.212	0.217	0.221	0.226	0.230	0.235	0.240	0.245	0.249	0.255	0.260	0.265	0.270	0.276	0.281	0.287	0.293
35	**Total Annual Volumetric Contract Rate ($/GJ)**	Sum of Line 32 to Line 34	**2.878**	**2.935**	**2.994**	**3.054**	**3.116**	**3.178**	**3.242**	**3.086**	**3.068**	**3.039**	**3.004**	**2.964**	**2.920**	**2.872**	**2.821**	**2.769**	**2.714**	**2.659**	**2.603**	**2.517**
36	**Annual Forecast Revenue**	(Line 30 x Line 35) x 1000	**287,755**	**293,532**	**299,424**	**305,434**	**311,565**	**317,819**	**324,199**	**308,606**	**306,799**	**303,900**	**300,446**	**296,434**	**291,985**	**287,193**	**282,134**	**276,869**	**271,448**	**265,911**	**260,289**	**251,735**
37																						
38	**Contract Termination[4]**																					
39																						
40	Deferral Account Repayment	Schedule 9, Line 37	39,231	30,003	27,059	25,179	21,602	13,922	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Residual Asset Value	[5]	1,790,238	1,695,475	1,600,712	1,505,949	1,411,186	1,316,423	1,221,660	1,126,897	1,032,134	937,371	842,608	747,845	653,082	558,320	463,557	368,794	274,031	179,268	84,505	(258)
42	Add: Removal Costs	[5]																				
43	Less: Excess Fueling Station Recoveries	[6]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Total	Line 40 + Line 43	1,829,470	1,725,479	1,627,771	1,531,128	1,432,788	1,330,345	1,221,660	1,126,897	1,032,134	937,371	842,608	747,845	653,082	558,320	463,557	368,794	274,031	179,268	84,505	(258)
45	Approximate Contract Termination Fee ($)		1,829,470	1,725,479	1,627,771	1,531,128	1,432,788	1,330,345	1,221,660	1,126,897	1,032,134	937,371	842,608	747,845	653,082	558,320	463,557	368,794	274,031	179,268	84,505	-
46																						

47 1- Line 3 /sum of [(1+2%) ^ year / (1+WACC) ^ year] for each year of the contract
48 2- Previous Year x (1+ 2%); in 2019+, Line 20
49 3- Previous Year x (1+ BC CPI)
50 4- The forecast early termination fee has been calculated on a year end basis. The actual fee would be determined at the time of contract termination and may be different than the amount shown on Line 45. Reference to Section 12B.5, Clause 11.1 of Appendix B in BFI Application
51 5- Schedule 5, (Line 3 + Line 6+ Line 9+ Line 12+ Line 15 + Schedule 8 Line 55) x 1000
52 6- Termination Fee tab, Line 6

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A): Discounted Cash Flow Analysis
Appendix D - Schedule 12
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cash Flow**																					
2	Add: Revenue	Schedule 11, Line 36	288	294	299	305	312	318	324	309	307	304	300	296	292	287	282	277	271	266	260	252
3	Less: O&M, Property Tax Expense	Schedule 1, - (Line 3 + Line 4)	(67)	(69)	(72)	(74)	(75)	(77)	(78)	(80)	(81)	(83)	(85)	(86)	(88)	(89)	(91)	(93)	(95)	(97)	(98)	(100)
4	EBITDA[1]	Line 2 + Line 3	220	225	227	232	236	241	246	229	225	221	216	210	204	198	191	184	177	169	162	151
5	Capital Expenditures[2]	Schedule 6, Line 25 + Line 29	(1,861)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
6	Pre-Tax Cash Flow	Line 4 + Line 5	(1,640)	225	227	232	236	241	246	229	225	221	216	210	204	198	191	184	177	169	162	141
7	Income Tax Expense	Line 4 x (- Schedule 3, Line 13)	(55)	(56)	(57)	(58)	(59)	(60)	(61)	(57)	(56)	(55)	(54)	(53)	(51)	(49)	(48)	(46)	(44)	(42)	(40)	(38)
8	Overhead Capitalized Tax Shield	Schedule 3, -Line 8 x Line 13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	CCA Tax Shield/Removal Cost	Schedule 3, (-Line 9 + Line 10) x Schedule 3, Line 13	39	70	57	47	38	31	26	21	18	15	12	10	9	7	6	6	5	4	4	6
10	Terminal Value of CCA Tax Shield	[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
11	Terminal Value	[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Free Cash Flow	Line 6 + Line 7	(1,657)	239	228	220	215	212	210	193	187	180	174	168	162	156	150	143	137	131	125	128
14																						
15	After Tax WACC %	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
16	Present Value of Free Cash Flow [3]	Line 13 / (1 + Line 15)^Yr	(1,670)	209	186	169	154	142	132	113	102	93	84	75	68	61	55	49	44	40	35	34
17	Total Present Value of Free Cash Flow	Sum of Line 16	**176**																			
18																						

19 1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)
20 2- Net of CIAC and removal costs (if applicable) and excludes capitalized overhead
21 3- 2012 present value calculates capital expenditure to occur at time zero
22 4- [Class 8 UCC Closing Balance x CCA Rate / (CCA Rate + WACC) + Class 1.3 UCC Closing Balance x CCA Rate / (CCA Rate + WACC)] x Income Tax Rate
23 5- Evaluation period reflects the useful life of the assets, therefore it is assumed that the terminal value is zero

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (A)

CNG BFI Cost of Service: Approximate Contract Termination Fee
Appendix B - Section 12B.5, Clause 11.1
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Total Gross Plant in Service, Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
2	Accumulated Depreciation, Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
3	Net Salvage, Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
4	Deferral Account Repayment	Schedule 9, Line 37	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Add: Removal Costs[1]																					
6	Less: Excess Fueling Station Recoveries[2]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total	Sum of Line 1 to Line 6	1,829	1,725	1,628	1,531	1,433	1,330	1,222	1,127	1,032	937	843	748	653	558	464	369	274	179	85	(0)
8	**Net Termination Payment[3]**		**1,829**	**1,725**	**1,628**	**1,531**	**1,433**	**1,330**	**1,222**	**1,127**	**1,032**	**937**	**843**	**748**	**653**	**558**	**464**	**369**	**274**	**179**	**85**	**-**
9																						
10																						
11		O&M Rate	0.7	0.714	0.729	0.744	0.759	0.774	0.79	0.806	0.822	0.839	0.856	0.873	0.891	0.909	0.927	0.946	0.965	0.985	1.005	1.025
12		Capital Rate	1.089	1.111	1.133	1.155	1.179	1.202	1.226	1.14	1.123	1.1	1.074	1.046	1.014	0.981	0.947	0.911	0.875	0.837	0.799	0.746
13		Total Charge	**1.789**	**1.825**	**1.862**	**1.899**	**1.938**	**1.976**	**2.016**	**1.946**	**1.945**	**1.939**	**1.930**	**1.919**	**1.905**	**1.890**	**1.874**	**1.857**	**1.840**	**1.822**	**1.804**	**1.771**
14																						
15	Volume in Excess of Minimum Contract Demand		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						

17 1- Actual removal costs to be determined at time of contract termination and will be less the net salvage collected to date

18 2- Cumulative fueling station recoveries received from volumes in excess of minimum contract demand

19 3- Excess fueling station recoveries will be credited to a maximum amount of the net book value of the assets. That is, the net termination payment cannot be negative.

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Revenue Requirement
Appendix D - Schedule 1
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Revenue Requirement**																					
2	Cost of Energy Sold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	Schedule 2, Line 19	50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
4	Property Taxes	Schedule 2, Line 29	17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
5	Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
6	Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
7	Amortization Expense	Schedule 9, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	Schedule 2, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	Schedule 3, Line 20	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
10	Earned Return	Schedule 5, Line 27	142	138	130	123	115	108	100	93	85	78	70	63	55	48	40	33	25	18	10	3
11																						
12	**Annual Revenue Requirement**	Sum of Lines 2 through 10	**307**	**261**	**274**	**280**	**285**	**287**	**287**	**286**	**283**	**280**	**276**	**271**	**267**	**261**	**256**	**250**	**244**	**238**	**232**	**222**

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): O&M, Other Revenue and Property Tax
Appendix D - Schedule 2
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross O&M**																					
2	Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																						
4	Vehicle Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Employee Expenses		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Materials & Supplies		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Computer Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Fees & Administrations Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contractor Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
10	Facilities		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Recoveries & Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Non-Labour Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
14																						
15	Total Gross O&M Expenses		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
16																						
17	(Less): Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Add (Less): Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
20																						
21	**Other Revenue**																					
22	Environmental Credits		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Property Taxes**																					
27	General, School and Other		17	18	18	18	19	19	19	20	20	21	21	22	22	22	23	23	24	24	25	25
28	1% in Lieu of General Municipal Tax[1]	Schedule 11, Line 36/1000 x 1%	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
29	Total Property Taxes		17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
30																						
31	1- Calculation is based on the second preceeding year; ex., 2012 is based on 2010 revenue																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Income Tax Expense
Appendix D - Schedule 3
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Income Tax Expense**																					
2																						
3	Earned Return	Schedule 5, Line 27	142	138	130	123	115	108	100	93	85	78	70	63	55	48	40	33	25	18	10	3
4	Deduct: Interest on debt	Schedule 5, Line 26	(74)	(72)	(68)	(64)	(60)	(56)	(52)	(48)	(44)	(40)	(37)	(33)	(29)	(25)	(21)	(17)	(13)	(9)	(5)	(2)
5	Add (Deduct): Amortization Expense	Schedule 9, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
7	Add: Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	Deduct: Overhead Capitalized Expensed for Tax Purposes		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct Removal Costs	Schedule 8, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
10	Deduct: Capital Cost Allowance	Schedule 4, Line 29	(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
11	Taxable Income After Tax	Sum of Lines 3 through 10	8	(120)	(71)	(33)	(2)	22	40	55	65	74	79	84	86	88	88	88	88	86	85	73
12																						
13	Income Tax Rate		25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
14	1 - Current Income Tax Rate	1 - Line 13	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
15																						
16	Taxable Income	Line 11 / Line 14	11	(160)	(95)	(43)	(3)	29	54	73	87	98	106	111	115	117	118	118	117	115	113	98
17																						
18	Total Income Tax Expense	Line 16 x Line 13	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
19	Adjustments		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Net Tax Expense	Line 18 + Line 19	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
21																						
22	Loss Carry-forward	Loss Carry-forward doesn't apply																				
23	Opening Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Loss Carry-forward		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Loss Utilization		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Closing Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Capital Cost Allowance
Appendix D - Schedule 4
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**CNG Dispensing Equipment- Class 8 @ 20%**																					
2	Opening Balance	Preceeding Year, Line 5	-	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22
3	Additions	Schedule 7 , Line 11 - AFUDC	1,376	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(138)	(248)	(198)	(158)	(127)	(101)	(81)	(65)	(52)	(42)	(33)	(27)	(21)	(17)	(14)	(11)	(9)	(7)	(6)	(4)
5	Closing Balance	Sum of Lines 2 through 4	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22	18
6																						
7	**Foundation- Class 1.3 @ 6%**																					
8	Opening Balance	Preceeding Year, Line 11	-	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141
9	Additions	Schedule 7 , Line 12 - AFUDC	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(13)	(26)	(24)	(23)	(21)	(20)	(19)	(18)	(17)	(16)	(15)	(14)	(13)	(12)	(12)	(11)	(10)	(10)	(9)	(8)
11	Closing Balance	Sum of Lines 8 through 10	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141	132
12																						
13	**NG Dehydrator- Class 8 @ 20%**																					
14	Opening Balance	Preceeding Year, Line 17	-	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1
15	Additions	Schedule 7 , Line 13 - AFUDC	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(4)	(8)	(6)	(5)	(4)	(3)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
17	Closing Balance	Sum of Lines 14 through 16	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1	1
18																						
19																						
20	**Capitalized Overhead- Class 0 @ 0%**																					
21	Opening Balance	Preceeding Year, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Additions	Schedule 2 , Line 17 x 0 / 0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	CCA	[Line 21 + (Line 22 x 1/2)] x CCA Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Closing Balance	Sum of Lines 21 through 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Total CCA**																					
27	Opening Balance	Preceeding Year, Line 30	-	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164
28	Additions	[1]	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	CCA		(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
30	Closing Balance	Sum of Lines 27 through 29	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164	151
31																						
32	1- Schedule 7 , Line 19 - Line 18, + Line 22 above - AFUDC																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Rate Base
Appendix D - Schedule 5
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Rate Base**																					
2	Gross Plant In Service- Beginning	Schedule 7, Line 10	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
3	Gross Plant In Service- Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
4																						
5	Accumulated Depreciation- Beginning	Schedule 8, Line 10	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
6	Accumulated Depreciation- Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
7																						
8	Contributions in Aid of Construction- Beginning	Schedule 7, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contributions in Aid of Construction- Ending	Schedule 7, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10																						
11	Negative Salvage - Beginning	Schedule 8, Line 53	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
12	Negative Salvage - Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
13																						
14	Accumulated Amortization- Beginning	Schedule 8, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	Schedule 8, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17	Net Plant in Service, Mid-Year	Sum (Lines 2 through 15)/2	895	1,743	1,648	1,553	1,459	1,364	1,269	1,174	1,080	985	890	795	700	606	511	416	321	227	132	42
18																						
19	Adjustment to 13-month average	[1]	900	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	Schedule 9, Line 58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	[2]	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
22	**Total Rate Base**	**Sum of Lines 17 through 21**	**1,792**	**1,739**	**1,644**	**1,550**	**1,455**	**1,360**	**1,265**	**1,171**	**1,076**	**981**	**886**	**791**	**697**	**602**	**507**	**412**	**318**	**223**	**128**	**38**
23																						
24	**Return on Rate Base**																					
25	Equity Return	Line 22 x ROE x Equity %	68	66	62	59	55	52	48	44	41	37	34	30	26	23	19	16	12	8	5	1
26	Debt Component	[3]	74	72	68	64	60	56	52	48	44	40	37	33	29	25	21	17	13	9	5	2
27	Total Earned Return	Line 25 + Line 26	**142**	**138**	**130**	**123**	**115**	**108**	**100**	**93**	**85**	**78**	**70**	**63**	**55**	**48**	**40**	**33**	**25**	**18**	**10**	**3**
28	Return on Rate Base %	Line 27 / Line 22	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
29																						
30	1- [Schedule 7, (Line 19 + Line 42) + Schedule 8, (Line 19+ Line 42)] x (Days In-service/365-1/2)																					
31	2- Schedule 7, Line 37 x FEI CWC/Closing GPIS %																					
32	3- Line 22 x (LTD Rate x LTD% + STD Rate x STD %)																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Capital Spending
Appendix D - Schedule 6
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Capital Spending Prior to 2012																					
2	CNG Dispensing Equipment		1,376																			
3	Foundation		442																			
4	NG Dehydrator		43																			
5	Total Capital Spending Prior to 2012	Sum of Lines 2 through 4	1,861																			
6																						
7	AFUDC Prior to 2012																					
8	CNG Dispensing Equipment		24																			
9	Foundation		-																			
10	NG Dehydrator		1																			
11	Total AFUDC Prior to 2012	Sum of Lines 8 through 10	25																			
12																						
13	Capital Spending 2012 Onwards																					
14	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Capital Spending 2012 Onwards	Sum of Lines 14 through 16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																						
19	AFUDC 2012 Onwards																					
20	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total AFUDC 2012 Onwards	Sum of Lines 20 through 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																						
25	Total Capital Spending[1]	Line 5 + Line 17	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total AFUDC	Line 11 + Line 23	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Total Annual Capital Spending and AFUDC	Line 25 + Line 26	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28																						
29	Contributions in Aid of Construction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
31	Net Annual Project Costs- Capital	Line 27 + Line 29 + Line 30	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
32																						
33	Total Project Costs- Capital Spending and AFUDC	Sum of Line 27	**1,885**																			
34	Total Net Project Costs- including CIAC & Removal Costs	Sum of Line 31	**1,895**																			
35																						
36	1- Excluding capitalized overhead; First year of analysis includes all prior year spending																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Gross Plant in Service & Contributions in Aid of Construction
Appendix D - Schedule 7
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross Plant in Service**																					
2																						
3	Gross Plant in Service, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
5	Foundation	Preceeding Year, Line 32	-	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
6	NG Dehydrator	Preceeding Year, Line 33	-	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 9	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
11																						
12	Gross Plant in Service, Additions																					
13	CNG Dispensing Equipment	Schedule 6, Lines 2 + 8 + 14 + 20	1,400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Foundation	Schedule 6, Lines 3 + 9 + 15 + 21	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	NG Dehydrator	Schedule 6, Lines 4 + 10 + 16 + 22	44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17																						
18	Capitalized Overhead	Schedule 2, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Gross Plant in Service, Additions	Sum of Lines 13 through 18	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																						
21	Gross Plant in Service, Retirements																					
22	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Gross Plant in Service, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Gross Plant in Service, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
32	Foundation	Line 5 + Line 14 + Line 23	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
33	NG Dehydrator	Line 6 + Line 15 + Line 24	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Gross Plant in Service, Ending	Sum of Lines 31 through 36	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
38																						
39																						
40	**Contributions in Aid of Construction (CIAC)**																					
41	CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Accumulated Depreciation & Amortization
Appendix D - Schedule 8
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Accumulated Depreciation**																					
2																						
3	Accumulated Depreciation, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)
5	Foundation	Preceeding Year, Line 32	-	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)
6	NG Dehydrator	Preceeding Year, Line 33	-	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 9	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
11																						
12	Accumulated Depreciation, Depreciation Expense[1]																					
13	CNG Dispensing Equipment@ 5%	Schedule 7, Line 4 & Line 13	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
14	Foundation@ 5%	Schedule 7, Line 5 & Line 14	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
15	NG Dehydrator@ 5%	Schedule 7, Line 6 & Line 15	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
16																						
17																						
18	Capitalized Overhead@ 0%	Schedule 7, Line 9 & Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Accumulated Depreciation, Depreciation Expe	Sum of Lines 13 through 18	(95)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)
20																						
21	Accumulated Depreciation, Retirements																					
22	CNG Dispensing Equipment	Schedule 7, Line 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation	Schedule 7, Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator	Schedule 7, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead	Schedule 7, Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Accumulated Depreciation, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Accumulated Depreciation, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)	(1,400)
32	Foundation	Line 5 + Line 14 + Line 23	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)	(442)
33	NG Dehydrator	Line 6 + Line 15 + Line 24	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)	(44)
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Accumulated Depreciation, Ending	Sum of Lines 31 through 36	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
38																						
39																						
40	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**																					
41	Accumulated Amortization CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Amortization	[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Accumulated Amortization CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45																						
46	**Removal Cost Provision**																					
47	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Foundation	-Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
49	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Total Removal Cost Provision	Sum of Lines 47 through 49	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
51																						
52	**Negative Salvage Continuity - Foundation**																					
53	Opening Balance	Preceeding Year, Line 56	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
54	Provision (Cr.)[2]	Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
55	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
56	Ending Balance	Sum of Lines 53 through 55	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
57																						
58	1- Depreciation & Amortization Expense calculation is based on opening balance + (additions x in-service days/365 if it is the in-service year for project/; otherwise, additions x 1/2)																					
59	2- Annual Salvage Rate calculation is 0.11% based on (foundation costs / removal costs / retirement years																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Deferred Charges & Deficiency / Surplus [Tracker]
Appendix D - Schedule 9
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	*Deferred Charge- O&M*																					
2	Opening Balance	Previous Year, Line 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	Line 3 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	(Lines 2 + 3 + 4) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	Sum of Lines 3 through 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Closing Balance	Lines 2 + 6 + 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																						
10	*Deferred Charge- Property Tax*																					
11	Opening Balance	Previous Year, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	Line 12 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	(Lines 11 + 12 + 13) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	Sum of Lines 12 through 14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	Lines 11 + 15 + 16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																						
19	*Deferred Charge- (Gain)/Loss on Asset Disposal*																					
20	Opening Balance	Previous Year, Line 26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Tax	Line 21 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	AFUDC	(Lines 20 + 21 + 22) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Net Additions	Sum of Lines 21 through 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Amortization Expense @ years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Closing Balance	Lines 20 + 24 + 25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27																						
28	**Deficiency / Surplus [Tracker]**																					
29	Opening Balance	Previous Year, Line 37	-	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gross Addition	Schedule 11, Line 21	39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Net Addition	Line 30 + Line 31	39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
33	AFUDC																					
34	Equity	(Line 29) x (Schedule 10, Lines 8 x 9)	-	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Debt	[1]	-	1	1	1	1	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Interest Adjustment	[2]	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Closing Balance	Sum of Lines 32 through 36	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38																						
39	**Deferred Charge- Non Rate Base**																					
40	Opening Balance	Previous Year, Line 47	-	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Opening Balance, Adjustment	Opening balance transfer to rate base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Gross Additions		39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	AFUDC		-	3	2	2	2	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
45	Net Additions	Sum of Lines 42 through 44	39	(9)	(3)	(2)	(4)	(8)	(14)	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Closing Balance	Lines 40 + 41 + 45 + 46	39	30	27	25	22	14	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-
48																						
49	**Deferred Charge- Rate Base**																					
50	Opening Balance	Previous Year, Line 57	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Closing Balance	Line 50 + Line 54 + Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57																						
58	Deferred Charge, Mid-Year	(Line 50+ Line 51 + Line 56) / 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59																						
60	1- (Line 29) x [Schedule 10 , (Lines 11 x 12+ Lines 13 x 14) x (1- Tax Rate)]																					
61	2- Adjustment to net account to zero in final year; result of varying WACC rates throughout contract																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Present Value of Revenue Requirement
Appendix D - Schedule 10
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1																						
2	Annual Revenue Requirement (Excluding O&M)	Schedule 1, Line 12 -Line 3	257.0	210.2	221.5	227.3	230.4	231.2	230.3	228.0	224.6	220.0	214.9	209.1	202.9	196.3	189.4	182.2	174.9	167.4	159.8	149.2
3	Annual Number of Customers		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	Annual Revenue Requirement (O&M)	Schedule 1, Line 3	50.0	51.0	52.1	53.1	54.2	55.3	56.4	57.6	58.7	59.9	61.1	62.4	63.6	64.9	66.2	67.6	69.0	70.4	71.8	73.2
5																						
6	**Annual Discount Rate**																					
7	Equity Component																					
8	ROE %		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
9	Equity Portion		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
10	Debt Component																					
11	Long Term Debt Rate		6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%
12	Long Term Debt Portion		58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%
13	Short Term Debt Rate		4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
14	Short Term Debt Portion		1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%
15																						
16	Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Pre- Tax Weighted Average Cost of Capital (WACC)[1]		9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
18	After- Tax Weighted Average Cost of Capital (WACC)[2]		6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
19																						
20	**Present Value of Revenue Requirement**																					
21	PV of Annual Cost of Service (excl O&M) Revenue Requirement	Line 2 / (1 + Line 18)^Yr	240.4	183.9	181.4	174.1	165.1	155.0	144.4	133.8	123.2	112.9	103.2	93.9	85.3	77.2	69.7	62.7	56.3	50.4	45.0	39.3
22	PV of Annual Revenue Requirement ($/Mnth)		20	15	15	15	14	13	12	11	10	9	9	8	7	6	6	5	5	4	4	3
23	Total PV of Cost of Service (excl O&M)	Sum of Line 21	2,297.3																			
24	Total PV of Cost of Service (excl O&M) over contract term		1,244.3																			
25	PV of Annual O&M	Line 4 / (1 + Line 18)^Yr	46.8	44.6	42.6	40.7	38.8	37.1	35.4	33.8	32.2	30.8	29.4	28.0	26.7	25.5	24.4	23.3	22.2	21.2	20.2	19.3
26	Total PV of O&M	Sum of Line 25	622.9																			
27	Total PV of O&M over contract term		286.0																			
28																						
29	PV of Annual Customers	Line 3 / (1 + Line 18)^Yr	0.9	0.9	0.8	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
30	Total PV of Customers	Sum of Line 29	10.6																			
31																						
32																						
33	**Tariff Analysis**																					
34	Annual Volume (TJ)		60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
35																						
36	**Cost of Service (excluding O&M)**																					
37	Annual Cost of Service per Customer ($/Yr)	Line 2 x 1000 / Line 3	256,987	210,177	221,539	227,338	230,393	231,250	230,346	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
38	Monthly Cost of Service per Customer ($/Mnth)	Line 37 / 12	21,416	17,515	18,462	18,945	19,199	19,271	19,196	19,003	18,716	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
39	Annual Volumetric Cost of Service ($/GJ)	Line 2 / Line 34	4.283	3.503	3.692	3.789	3.840	3.854	3.839	3.801	3.743	3.667	3.581	3.485	3.382	3.272	3.156	3.037	2.915	2.790	2.663	2.486
40																						
41	**O&M**																					
42	Annual Cost of Service per Customer ($/Yr)	Line 4 x 1000 / Line 3	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
43	Monthly Cost of Service per Customer ($/Mnth)	Line 42 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
44	Annual Volumetric Cost of Service ($/GJ)	Line 4 / Line 34	0.833	0.850	0.868	0.885	0.903	0.921	0.940	0.959	0.979	0.999	1.019	1.040	1.061	1.082	1.104	1.127	1.149	1.173	1.197	1.221
45																						
46	**Levelized Tariff Analysis**																					
47	PV of Annual Volume (TJ)	Line 34 / (1 + Line 18)^Yr	56.1	52.5	49.1	46.0	43.0	40.2	37.6	35.2	32.9	30.8	28.8	27.0	25.2	23.6	22.1	20.6	19.3	18.1	16.9	15.8
48	Total PV of Volume (TJ)	Sum of Line 47	640.8																			
49																						
50	Levelized Annual Delivery Charge per Customer ($/Yr)	Line 23 x 1000 / Line 30	**274,315**																			
51	Levelized Monthly Delivery Charge per Customer ($/Mnth)	Line 50 / 12	**22,860**																			
52	Levelized Volumetric Delivery Rate ($/GJ)	(Line 23 + Line 26) / Line 48	**4.557**																			
53																						
54	1- (Line 8 x Line 9) / 1- Line 16 + (Line 11 x Line 12 + Line 13 x Line 14)																					
55	2- Line 9 x Line 10 + [(Line 12 x Line 13 + Line 14 x Line 15) x 1- Line 17]																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Contract Rate Design
Appendix D - Schedule 11
($), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cost of Service (Excluding O&M)**																					
2	Required Delivery Revenue ($) (discounted) - 20 years	Schedule 10, Line 23 x 1000	2,297,264																			
3	Required Delivery Revenue ($) (discounted, contract term) - 7 yrs	Schedule 10, Line 24 x 1000	1,244,340																			
4	Flat Rate for 20 Years		274,315																			
5																						
6	Year 1 Contract Rate, Escalated at 2% Annually	[1]	217,755																			
7	Annual Contract Rate Escalation		2.00%																			
8																						
9	Annual Discount Rate (After- Tax WACC)	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
10	Annual Contract Rate	[2]	217,755	222,111	226,553	231,084	235,706	240,420	245,228	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
11	PV of Annual Contract Rate	Line 10 / (1 + Line 9)^Yr	203,709	194,380	185,478	176,984	168,879	161,145	153,765	133,760	123,243	112,948	103,185	93,946	85,272	77,176	69,658	62,706	56,298	50,408	45,010	39,315
12	Cumulative Revenue		439,866	222,111	666,419	897,503	1,133,208	1,373,628	1,618,856	1,846,888	2,071,478	2,291,500	2,506,365	2,715,480	2,918,375	3,114,669	3,304,058	3,486,300	3,661,200	3,828,603	3,988,384	4,137,570
13	PV of Cumulative Revenue		398,089	194,380	379,858	556,842	725,721	886,866	1,040,631	1,174,391	1,297,634	1,410,581	1,513,767	1,607,713	1,692,985	1,770,161	1,839,819	1,902,525	1,958,823	2,009,231	2,054,241	2,093,555
14	PV of Revenue Collected	Sum of Line 11	2,297,264																			
15																						
16																						
17	Monthly Rate, Escalated at 2% annually and then COS based beyond Contract Term		18,146	18,509	18,879	19,257	19,642	20,035	20,436	19,003	18,716	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
18	Annual Volumetric Contract Rate ($/GJ)	Line 10 / Line 30 / 1000	**3.629**	**3.702**	**3.776**	**3.851**	**3.928**	**4.007**	**4.087**	**3.801**	**3.743**	**3.667**	**3.581**	**3.485**	**3.382**	**3.272**	**3.156**	**3.037**	**2.915**	**2.790**	**2.663**	**2.486**
19																						
20	Annual Cost of Service (excl O&M)	Schedule 10, Line 2 x 1000	256,987	210,177	221,539	227,338	230,393	231,250	230,346	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
21	Annual Difference (Cost of Service - Contract Rate)	Line 20 - Line 10	39,231	(11,933)	(5,014)	(3,746)	(5,313)	(9,170)	(14,882)	-	-	-	-	-	-	-	-	-	-	-	-	-
22																						
23	**Cost of Service (O&M)**																					
24	Forecast Annual BC CPI Rate	CPI BC Stats Canada	1.99%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%
25	Annual O&M Expense	Schedule 1, Line 3 x 1000	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
26																						
27	Monthly Rate, Escalated at CPI annually	Line 25 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
28	Annual O&M Volumetric Contract Rate ($/GJ)	Line 25 / Line 30 / 1000	**0.833**	**0.850**	**0.868**	**0.885**	**0.903**	**0.921**	**0.940**	**0.959**	**0.979**	**0.999**	**1.019**	**1.040**	**1.061**	**1.082**	**1.104**	**1.127**	**1.149**	**1.173**	**1.197**	**1.221**
29																						
30	Annual Volume (TJ)	Minimum contract demand	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
31																						
32	Cost of Service (excl O&M) Volumetric Contract Rate ($/GJ)	Line 18	3.629	3.702	3.776	3.851	3.928	4.007	4.087	3.801	3.743	3.667	3.581	3.485	3.382	3.272	3.156	3.037	2.915	2.790	2.663	2.486
33	O&M Volumetric Contract Rate ($/GJ)	Line 28	0.833	0.850	0.868	0.885	0.903	0.921	0.940	0.959	0.979	0.999	1.019	1.040	1.061	1.082	1.104	1.127	1.149	1.173	1.197	1.221
34	Annual Overhead Allocation Charge ($/GJ)	[3]	0.200	0.204	0.208	0.212	0.217	0.221	0.226	0.230	0.235	0.240	0.245	0.249	0.255	0.260	0.265	0.270	0.276	0.281	0.287	0.293
35	**Total Annual Volumetric Contract Rate ($/GJ)**	Sum of Line 32 to Line 34	**4.663**	**4.756**	**4.852**	**4.949**	**5.048**	**5.150**	**5.253**	**4.990**	**4.957**	**4.905**	**4.844**	**4.774**	**4.697**	**4.613**	**4.526**	**4.434**	**4.340**	**4.244**	**4.147**	**4.000**
36	**Annual Forecast Revenue**	(Line 30 x Line 35) x 1000	**279,755**	**285,369**	**291,096**	**296,937**	**302,895**	**308,973**	**315,173**	**299,398**	**297,404**	**294,314**	**290,665**	**286,455**	**281,803**	**276,805**	**271,535**	**266,055**	**260,414**	**254,653**	**248,802**	**240,015**
37																						
38	**Contract Termination**[4]																					
39																						
40	Deferral Account Repayment	Schedule 9, Line 37	39,231	30,003	27,059	25,179	21,602	13,922	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Residual Asset Value	[5]	1,790,238	1,695,475	1,600,712	1,505,949	1,411,186	1,316,423	1,221,660	1,126,897	1,032,134	937,371	842,608	747,845	653,082	558,320	463,557	368,794	274,031	179,268	84,505	(258)
42	Add: Removal Costs	[5]																				
43	Less: Excess Fueling Station Recoveries	[6]	-	(116,200)	(234,760)	(355,720)	(479,080)	(604,920)	(733,320)	(856,880)	(980,320)	(1,103,200)	(1,225,360)	(1,346,640)	(1,466,880)	(1,586,000)	(1,703,880)	(1,820,520)	(1,935,840)	(2,049,800)	(2,162,440)	(2,272,720)
44	Total	Sum of Lines 40 to Line 43	1,829,470	1,841,679	1,862,531	1,886,848	1,911,868	1,935,265	1,954,980	1,983,777	2,012,454	2,040,571	2,067,968	2,094,485	2,119,962	2,144,320	2,167,437	2,189,314	2,209,871	2,229,068	2,246,945	2,272,462
45	Approximate Contract Termination Fee ($)		1,829,470	1,841,679	1,862,531	1,886,848	1,911,868	1,935,265	1,954,980	1,983,777	2,012,454	-	-	-	-	-	-	-	-	-	-	-
46																						

47 1- Line 3 /sum of [(1+2%) ^ year / (1+WACC) ^ year] for each year of the contract
48 2- Previous Year x (1+ 2%); in 2019+, Line 20
49 3- Previous Year x (1+ BC CPI)
50 4- The forecast early termination fee has been calculated on a year end basis. The actual fee would be determined at the time of contract termination and may be different than the amount shown on Line 45. Reference to Section 12B.5, Clause 11.1 of Appendix B in BFI Application
51 5- Schedule 5, (Line 3 + Line 6+ Line 9+ Line 12+ Line 15 + Schedule 8 Line 55) x 1000
52 6- Termination Fee tab, Line 6

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B): Discounted Cash Flow Analysis
Appendix D - Schedule 12
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cash Flow**																					
2	Add: Revenue	Schedule 11, Line 36	280	285	291	297	303	309	315	299	297	294	291	286	282	277	272	266	260	255	249	240
3	Less: O&M, Property Tax Expense	Schedule 1, - (Line 3 + Line 4)	(67)	(69)	(72)	(74)	(75)	(77)	(78)	(80)	(81)	(83)	(85)	(86)	(88)	(89)	(91)	(93)	(95)	(97)	(98)	(100)
4	EBITDA[1]	Line 2 + Line 3	212	217	219	223	228	232	237	220	216	211	206	200	194	187	180	173	166	158	150	140
5	Capital Expenditures[2]	Schedule 6, Line 25 + Line 29	(1,861)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
6	Pre-Tax Cash Flow	Line 4 + Line 5	(1,648)	217	219	223	228	232	237	220	216	211	206	200	194	187	180	173	166	158	150	130
7	Income Tax Expense	Line 4 x (- Schedule 3, Line 13)	(53)	(54)	(55)	(56)	(57)	(58)	(59)	(55)	(54)	(53)	(52)	(50)	(49)	(47)	(45)	(43)	(41)	(40)	(38)	(35)
8	Overhead Capitalized Tax Shield	Schedule 3, -Line 8 x Line 13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	CCA Tax Shield/Removal Cost	Schedule 3, (-Line 9 + Line 10) x Schedule 3, Line 13	39	70	57	47	38	31	26	21	18	15	12	10	9	7	6	6	5	4	4	6
10	Terminal Value of CCA Tax Shield	[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
11	Terminal Value	[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Free Cash Flow	Line 6 + Line 7	(1,663)	233	221	214	209	205	203	186	180	173	167	161	154	148	142	135	129	123	117	119
14																						
15	After Tax WACC %	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
16	Present Value of Free Cash Flow[3]	Line 13 / (1 + Line 15)^Yr	(1,675)	204	181	164	150	138	127	109	99	89	80	72	65	58	52	47	42	37	33	31
17	Total Present Value of Free Cash Flow	Sum of Line 16	**101**																			
18																						

19 1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)
20 2- Net of CIAC and removal costs (if applicable) and excludes capitalized overhead
21 3- 2012 present value calculates capital expenditure to occur at time zero
22 4- [Class 8 UCC Closing Balance x CCA Rate / (CCA Rate + WACC) + Class 1.3 UCC Closing Balance x CCA Rate / (CCA Rate + WACC)] x Income Tax Rate
23 5- Evaluation period reflects the useful life of the assets, therefore it is assumed that the terminal value is zero

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (B)

CNG BFI Cost of Service: Approximate Contract Termination Fee
Appendix B - Section 12B.5, Clause 11.1
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Total Gross Plant in Service, Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
2	Accumulated Depreciation, Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
3	Net Salvage, Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
4	Deferral Account Repayment	Schedule 9, Line 37	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Add: Removal Costs[1]																					
6	Less: Excess Fueling Station Recoveries[2]		-	(116)	(235)	(356)	(479)	(605)	(733)	(857)	(980)	(1,103)	(1,225)	(1,347)	(1,467)	(1,586)	(1,704)	(1,821)	(1,936)	(2,050)	(2,162)	(2,273)
7	Total	Sum of Line 1 to Line 6	1,829	1,609	1,393	1,175	954	725	488	270	52	(166)	(383)	(599)	(814)	(1,028)	(1,240)	(1,452)	(1,662)	(1,871)	(2,078)	(2,273)
8	**Net Termination Payment[3]**		**1,829**	**1,609**	**1,393**	**1,175**	**954**	**725**	**488**	**270**	**52**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9																						
10																						
11		O&M Rate	1.033	1.054	1.076	1.098	1.12	1.143	1.166	1.189	1.214	1.238	1.263	1.289	1.315	1.342	1.369	1.397	1.425	1.454	1.484	1.514
12		Capital Rate	1.815	1.851	1.888	1.926	1.964	2.003	2.044	1.9	1.872	1.834	1.791	1.743	1.691	1.636	1.578	1.519	1.458	1.395	1.332	1.243
13		Total Charge	**2.848**	**2.905**	**2.964**	**3.024**	**3.084**	**3.146**	**3.210**	**3.089**	**3.086**	**3.072**	**3.054**	**3.032**	**3.006**	**2.978**	**2.947**	**2.916**	**2.883**	**2.849**	**2.816**	**2.757**
14																						
15		Volume in Excess of Minimum Contract Demand	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
16																						
17	1- Actual removal costs to be determined at time of contract termination and will be less the net salvage collected to date																					
18	2- Cumulative fueling station recoveries received from volumes in excess of minimum contract demand																					
19	3- Excess fueling station recoveries will be credited to a maximum amount of the net book value of the assets. That is, the net termination payment cannot be negative.																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Revenue Requirement
Appendix D - Schedule 1
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Revenue Requirement**																					
2	Cost of Energy Sold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	Schedule 2, Line 19	50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
4	Property Taxes	Schedule 2, Line 29	17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
5	Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
6	Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
7	Amortization Expense	Schedule 9, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	Schedule 2, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	Schedule 3, Line 20	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
10	Earned Return	Schedule 5, Line 27	142	138	130	123	115	108	100	93	85	78	70	63	55	48	40	33	25	18	10	3
11																						
12	**Annual Revenue Requirement**	Sum of Lines 2 through 10	**307**	**261**	**274**	**280**	**285**	**287**	**287**	**286**	**283**	**280**	**276**	**271**	**267**	**261**	**256**	**250**	**244**	**238**	**232**	**222**

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): O&M, Other Revenue and Property Tax
Appendix D - Schedule 2
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross O&M**																					
2	Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																						
4	Vehicle Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Employee Expenses		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Materials & Supplies		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Computer Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Fees & Administrations Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contractor Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
10	Facilities		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Recoveries & Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Non-Labour Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
14																						
15	Total Gross O&M Expenses		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
16																						
17	(Less): Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Add (Less): Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
20																						
21	**Other Revenue**																					
22	Environmental Credits		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Property Taxes**																					
27	General, School and Other		17	18	18	18	19	19	19	20	20	21	21	22	22	22	23	23	24	24	25	25
28	1% in Lieu of General Municipal Tax[1]	Schedule 11, Line 36/1000 x 1%	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
29	Total Property Taxes		17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
30																						
31	1- Calculation is based on the second preceeding year; ex., 2012 is based on 2010 revenue																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Income Tax Expense
Appendix D - Schedule 3
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Income Tax Expense**																					
2																						
3	Earned Return	Schedule 5, Line 27	142	138	130	123	115	108	100	93	85	78	70	63	55	48	40	33	25	18	10	3
4	Deduct: Interest on debt	Schedule 5, Line 26	(74)	(72)	(68)	(64)	(60)	(56)	(52)	(48)	(44)	(40)	(37)	(33)	(29)	(25)	(21)	(17)	(13)	(9)	(5)	(2)
5	Add (Deduct): Amortization Expense	Schedule 9, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
7	Add: Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	Deduct: Overhead Capitalized Expensed for Tax Purposes		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct Removal Costs	Schedule 8, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
10	Deduct: Capital Cost Allowance	Schedule 4, Line 29	(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
11	Taxable Income After Tax	Sum of Lines 3 through 10	8	(120)	(71)	(33)	(2)	22	40	55	65	74	79	84	86	88	88	88	88	86	85	73
12																						
13	Income Tax Rate		25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
14	1 - Current Income Tax Rate	1 - Line 13	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
15																						
16	Taxable Income	Line 11 / Line 14	11	(160)	(95)	(43)	(3)	29	54	73	87	98	106	111	115	117	118	118	117	115	113	98
17																						
18	Total Income Tax Expense	Line 16 x Line 13	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
19	Adjustments		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Net Tax Expense	Line 18 + Line 19	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
21																						
22	Loss Carry-forward	Loss Carry-forward doesn't apply																				
23	Opening Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Loss Carry-forward		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Loss Utilization		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Closing Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Capital Cost Allowance
Appendix D - Schedule 4
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**CNG Dispensing Equipment- Class 8 @ 20%**																					
2	Opening Balance	Preceeding Year, Line 5	-	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22
3	Additions	Schedule 7 , Line 11 - AFUDC	1,376	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(138)	(248)	(198)	(158)	(127)	(101)	(81)	(65)	(52)	(42)	(33)	(27)	(21)	(17)	(14)	(11)	(9)	(7)	(6)	(4)
5	Closing Balance	Sum of Lines 2 through 4	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22	18
6																						
7	**Foundation- Class 1.3 @ 6%**																					
8	Opening Balance	Preceeding Year, Line 11	-	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141
9	Additions	Schedule 7 , Line 12 - AFUDC	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(13)	(26)	(24)	(23)	(21)	(20)	(19)	(18)	(17)	(16)	(15)	(14)	(13)	(12)	(12)	(11)	(10)	(10)	(9)	(8)
11	Closing Balance	Sum of Lines 8 through 10	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141	132
12																						
13	**NG Dehydrator- Class 8 @ 20%**																					
14	Opening Balance	Preceeding Year, Line 17	-	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1
15	Additions	Schedule 7 , Line 13 - AFUDC	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(4)	(8)	(6)	(5)	(4)	(3)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
17	Closing Balance	Sum of Lines 14 through 16	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1	1
18																						
19																						
20	**Capitalized Overhead- Class 0 @ 0%**																					
21	Opening Balance	Preceeding Year, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Additions	Schedule 2 , Line 17 x 0 / 0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	CCA	[Line 21 + (Line 22 x 1/2)] x CCA Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Closing Balance	Sum of Lines 21 through 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Total CCA**																					
27	Opening Balance	Preceeding Year, Line 30	-	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164
28	Additions	[1]	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	CCA		(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
30	Closing Balance	Sum of Lines 27 through 29	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164	151
31																						
32	1- Schedule 7 , Line 19 - Line 18, + Line 22 above - AFUDC																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Rate Base
Appendix D - Schedule 5
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Rate Base**																					
2	Gross Plant In Service- Beginning	Schedule 7, Line 10	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
3	Gross Plant In Service- Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
4																						
5	Accumulated Depreciation- Beginning	Schedule 8, Line 10	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
6	Accumulated Depreciation- Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
7																						
8	Contributions in Aid of Construction- Beginning	Schedule 7, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contributions in Aid of Construction- Ending	Schedule 7, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10																						
11	Negative Salvage - Beginning	Schedule 8, Line 53	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
12	Negative Salvage - Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
13																						
14	Accumulated Amortization- Beginning	Schedule 8, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	Schedule 8, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17	Net Plant in Service, Mid-Year	Sum (Lines 2 through 15)/2	895	1,743	1,648	1,553	1,459	1,364	1,269	1,174	1,080	985	890	795	700	606	511	416	321	227	132	42
18																						
19	Adjustment to 13-month average	[1]	900	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	Schedule 9, Line 58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	[2]	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
22	**Total Rate Base**	**Sum of Lines 17 through 21**	**1,792**	**1,739**	**1,644**	**1,550**	**1,455**	**1,360**	**1,265**	**1,171**	**1,076**	**981**	**886**	**791**	**697**	**602**	**507**	**412**	**318**	**223**	**128**	**38**
23																						
24	**Return on Rate Base**																					
25	Equity Return	Line 22 x ROE x Equity %	68	66	62	59	55	52	48	44	41	37	34	30	26	23	19	16	12	8	5	1
26	Debt Component	[3]	74	72	68	64	60	56	52	48	44	40	37	33	29	25	21	17	13	9	5	2
27	Total Earned Return	Line 25 + Line 26	**142**	**138**	**130**	**123**	**115**	**108**	**100**	**93**	**85**	**78**	**70**	**63**	**55**	**48**	**40**	**33**	**25**	**18**	**10**	**3**
28	Return on Rate Base %	Line 27 / Line 22	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
29																						
30	1- [Schedule 7, (Line 19 + Line 42) + Schedule 8, (Line 19+ Line 42)] x (Days In-service/365-1/2)																					
31	2- Schedule 7, Line 37 x FEI CWC/Closing GPIS %																					
32	3- Line 22 x (LTD Rate x LTD% + STD Rate x STD %)																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Capital Spending
Appendix D - Schedule 6
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Capital Spending Prior to 2012																					
2	CNG Dispensing Equipment		1,376																			
3	Foundation		442																			
4	NG Dehydrator		43																			
5	Total Capital Spending Prior to 2012	Sum of Lines 2 through 4	1,861																			
6																						
7	AFUDC Prior to 2012																					
8	CNG Dispensing Equipment		24																			
9	Foundation		-																			
10	NG Dehydrator		1																			
11	Total AFUDC Prior to 2012	Sum of Lines 8 through 10	25																			
12																						
13	Capital Spending 2012 Onwards																					
14	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Capital Spending 2012 Onwards	Sum of Lines 14 through 16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																						
19	AFUDC 2012 Onwards																					
20	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total AFUDC 2012 Onwards	Sum of Lines 20 through 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																						
25	Total Capital Spending[1]	Line 5 + Line 17	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total AFUDC	Line 11 + Line 23	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Total Annual Capital Spending and AFUDC	Line 25 + Line 26	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28																						
29	Contributions in Aid of Construction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
31	Net Annual Project Costs- Capital	Line 27 + Line 29 + Line 30	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
32																						
33	Total Project Costs- Capital Spending and AFUDC	Sum of Line 27	**1,885**																			
34	Total Net Project Costs- including CIAC & Removal Costs	Sum of Line 31	**1,895**																			
35																						
36	1- Excluding capitalized overhead; First year of analysis includes all prior year spending																					

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Gross Plant in Service & Contributions in Aid of Construction
Appendix D - Schedule 7
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross Plant in Service**																					
2																						
3	Gross Plant in Service, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
5	Foundation	Preceeding Year, Line 32	-	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
6	NG Dehydrator	Preceeding Year, Line 33	-	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 9	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
11																						
12	Gross Plant in Service, Additions																					
13	CNG Dispensing Equipment	Schedule 6, Lines 2 + 8 + 14 + 20	1,400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Foundation	Schedule 6, Lines 3 + 9 + 15 + 21	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	NG Dehydrator	Schedule 6, Lines 4 + 10 + 16 + 22	44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17																						
18	Capitalized Overhead	Schedule 2, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Gross Plant in Service, Additions	Sum of Lines 13 through 18	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																						
21	Gross Plant in Service, Retirements																					
22	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Gross Plant in Service, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Gross Plant in Service, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
32	Foundation	Line 5 + Line 14 + Line 23	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
33	NG Dehydrator	Line 6 + Line 15 + Line 24	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Gross Plant in Service, Ending	Sum of Lines 31 through 36	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
38																						
39																						
40	**Contributions in Aid of Construction (CIAC)**																					
41	CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Accumulated Depreciation & Amortization
Appendix D - Schedule 8
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Accumulated Depreciation**																					
2																						
3	Accumulated Depreciation, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)
5	Foundation	Preceeding Year, Line 32	-	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)
6	NG Dehydrator	Preceeding Year, Line 33	-	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 9	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
11																						
12	Accumulated Depreciation, Depreciation Expense[1]																					
13	CNG Dispensing Equipment@ 5%	Schedule 7, Line 4 & Line 13	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
14	Foundation@ 5%	Schedule 7, Line 5 & Line 14	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
15	NG Dehydrator@ 5%	Schedule 7, Line 6 & Line 15	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
16																						
17																						
18	Capitalized Overhead@ 0%	Schedule 7, Line 9 & Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Accumulated Depreciation, Depreciation Expe	Sum of Lines 13 through 18	(95)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)
20																						
21	Accumulated Depreciation, Retirements																					
22	CNG Dispensing Equipment	Schedule 7, Line 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation	Schedule 7, Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator	Schedule 7, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead	Schedule 7, Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Accumulated Depreciation, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Accumulated Depreciation, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)	(1,400)
32	Foundation	Line 5 + Line 14 + Line 23	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)	(442)
33	NG Dehydrator	Line 6 + Line 15 + Line 24	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)	(44)
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Accumulated Depreciation, Ending	Sum of Lines 31 through 36	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
38																						
39																						
40	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**																					
41	Accumulated Amortization CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Amortization	[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Accumulated Amortization CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45																						
46	**Removal Cost Provision**																					
47	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Foundation	-Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
49	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Total Removal Cost Provision	Sum of Lines 47 through 49	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
51																						
52	**Negative Salvage Continuity - Foundation**																					
53	Opening Balance	Preceeding Year, Line 56	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
54	Provision (Cr.)[2]	Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
55	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
56	Ending Balance	Sum of Lines 53 through 55	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
57																						

58 1- Depreciation & Amortization Expense calculation is based on opening balance + (additions x in-service days/365 if it is the in-service year for project/; otherwise, additions x 1/2)
59 2- Annual Salvage Rate calculation is 0.11% based on (foundation costs / removal costs / retirement years

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Deferred Charges & Deficiency / Surplus [Tracker]
Appendix D - Schedule 9
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	*Deferred Charge- O&M*																					
2	Opening Balance	Previous Year, Line 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	Line 3 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	(Lines 2 + 3 + 4) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	Sum of Lines 3 through 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Closing Balance	Lines 2 + 6 + 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																						
10	*Deferred Charge- Property Tax*																					
11	Opening Balance	Previous Year, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	Line 12 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	(Lines 11 + 12 + 13) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	Sum of Lines 12 through 14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	Lines 11 + 15 + 16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																						
19	*Deferred Charge- (Gain)/Loss on Asset Disposal*																					
20	Opening Balance	Previous Year, Line 26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Tax	Line 21 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	AFUDC	(Lines 20 + 21 + 22) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Net Additions	Sum of Lines 21 through 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Amortization Expense @ years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Closing Balance	Lines 20 + 24 + 25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27																						
28	**Deficiency / Surplus [Tracker]**																					
29	Opening Balance	Previous Year, Line 37	-	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gross Addition	Schedule 11, Line 21	39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Net Addition	Line 30 + Line 31	39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
33	AFUDC																					
34	Equity	(Line 29) x (Schedule 10, Lines 8 x 9)	-	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Debt	[1]	-	1	1	1	1	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Interest Adjustment	[2]	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Closing Balance	Sum of Lines 32 through 36	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38																						
39	**Deferred Charge- Non Rate Base**																					
40	Opening Balance	Previous Year, Line 47	-	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Opening Balance, Adjustment	Opening balance transfer to rate base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Gross Additions		39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	AFUDC		-	3	2	2	2	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
45	Net Additions	Sum of Lines 42 through 44	39	(9)	(3)	(2)	(4)	(8)	(14)	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Closing Balance	Lines 40 + 41 + 45 + 46	39	30	27	25	22	14	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-
48																						
49	**Deferred Charge- Rate Base**																					
50	Opening Balance	Previous Year, Line 57	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Closing Balance	Line 50 + Line 54 + Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57																						
58	Deferred Charge, Mid-Year	(Line 50+ Line 51 + Line 56) / 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59																						
60	1- (Line 29) x [Schedule 10 , (Lines 11 x 12+ Lines 13 x 14) x (1- Tax Rate)]																					
61	2- Adjustment to net account to zero in final year; result of varying WACC rates throughout contract																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Present Value of Revenue Requirement
Appendix D - Schedule 10
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1																						
2	Annual Revenue Requirement (Excluding O&M)	Schedule 1, Line 12 -Line 3	257.0	210.2	221.5	227.3	230.4	231.2	230.3	228.0	224.6	220.0	214.9	209.1	202.9	196.3	189.4	182.2	174.9	167.4	159.8	149.2
3	Annual Number of Customers		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	Annual Revenue Requirement (O&M)	Schedule 1, Line 3	50.0	51.0	52.1	53.1	54.2	55.3	56.4	57.6	58.7	59.9	61.1	62.4	63.6	64.9	66.2	67.6	69.0	70.4	71.8	73.2
5																						
6	**Annual Discount Rate**																					
7	Equity Component																					
8	ROE %		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
9	Equity Portion		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
10	Debt Component																					
11	Long Term Debt Rate		6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%
12	Long Term Debt Portion		58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%
13	Short Term Debt Rate		4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
14	Short Term Debt Portion		1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%
15																						
16	Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Pre- Tax Weighted Average Cost of Capital (WACC)[1]		9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
18	After- Tax Weighted Average Cost of Capital (WACC)[2]		6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
19																						
20	**Present Value of Revenue Requirement**																					
21	PV of Annual Cost of Service (excl O&M) Revenue Requirement	Line 2 / (1 + Line 18)^Yr	240.4	183.9	181.4	174.1	165.1	155.0	144.4	133.8	123.2	112.9	103.2	93.9	85.3	77.2	69.7	62.7	56.3	50.4	45.0	39.3
22	PV of Annual Revenue Requirement ($/Mnth)		20	15	15	15	14	13	12	11	10	9	9	8	7	6	6	5	5	4	4	3
23	Total PV of Cost of Service (excl O&M)	Sum of Line 21	2,297.3																			
24	Total PV of Cost of Service (excl O&M) over contract term		1,244.3																			
25	PV of Annual O&M	Line 4 / (1 + Line 18)^Yr	46.8	44.6	42.6	40.7	38.8	37.1	35.4	33.8	32.2	30.8	29.4	28.0	26.7	25.5	24.4	23.3	22.2	21.2	20.2	19.3
26	Total PV of O&M	Sum of Line 25	622.9																			
27	Total PV of O&M over contract term		286.0																			
28																						
29	PV of Annual Customers	Line 3 / (1 + Line 18)^Yr	0.9	0.9	0.8	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
30	Total PV of Customers	Sum of Line 29	10.6																			
31																						
32																						
33	**Tariff Analysis**																					
34	Annual Volume (TJ)		60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
35																						
36	**Cost of Service (excluding O&M)**																					
37	Annual Cost of Service per Customer ($/Yr)	Line 2 x 1000 / Line 3	256,987	210,177	221,539	227,338	230,393	231,250	230,346	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
38	Monthly Cost of Service per Customer ($/Mnth)	Line 37 / 12	21,416	17,515	18,462	18,945	19,199	19,271	19,196	19,003	18,716	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
39	Annual Volumetric Cost of Service ($/GJ)	Line 2 / Line 34	4.283	3.503	3.692	3.789	3.840	3.854	3.839	3.801	3.743	3.667	3.581	3.485	3.382	3.272	3.156	3.037	2.915	2.790	2.663	2.486
40																						
41	**O&M**																					
42	Annual Cost of Service per Customer ($/Yr)	Line 4 x 1000 / Line 3	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
43	Monthly Cost of Service per Customer ($/Mnth)	Line 42 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
44	Annual Volumetric Cost of Service ($/GJ)	Line 4 / Line 34	0.833	0.850	0.868	0.885	0.903	0.921	0.940	0.959	0.979	0.999	1.019	1.040	1.061	1.082	1.104	1.127	1.149	1.173	1.197	1.221
45																						
46	**Levelized Tariff Analysis**																					
47	PV of Annual Volume (TJ)	Line 34 / (1 + Line 18)^Yr	56.1	52.5	49.1	46.0	43.0	40.2	37.6	35.2	32.9	30.8	28.8	27.0	25.2	23.6	22.1	20.6	19.3	18.1	16.9	15.8
48	Total PV of Volume (TJ)	Sum of Line 47	640.8																			
49																						
50	Levelized Annual Delivery Charge per Customer ($/Yr)	Line 23 x 1000 / Line 30	**274,315**																			
51	Levelized Monthly Delivery Charge per Customer ($/Mnth)	Line 50 / 12	**22,860**																			
52	Levelized Volumetric Delivery Rate ($/GJ)	(Line 23 + Line 26) / Line 48	**4.557**																			
53																						
54	1- (Line 8 x Line 9) / 1- Line 16 + (Line 11 x Line 12 + Line 13 x Line 14)																					
55	2- Line 9 x Line 10 + [(Line 12 x Line 13 + Line 14 x Line 15) x 1- Line 17]																					

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Contract Rate Design
Appendix D - Schedule 11
($), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cost of Service (Excluding O&M)**																					
2	Required Delivery Revenue ($) (discounted) - 20 years	Schedule 10, Line 23 x 1000	2,297,264																			
3	Required Delivery Revenue ($) (discounted, contract term) - 7 yrs	Schedule 10, Line 24 x 1000	1,244,340																			
4	Flat Rate for 20 Years		274,315																			
5																						
6	Year 1 Contract Rate, Escalated at 2% Annually	[1]	217,755																			
7	Annual Contract Rate Escalation		2.00%																			
8																						
9	Annual Discount Rate (After- Tax WACC)	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
10	Annual Contract Rate	[2]	217,755	222,111	226,553	231,084	235,706	240,420	245,228	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
11	PV of Annual Contract Rate	Line 10 / (1 + Line 9)^Yr	203,709	194,380	185,478	176,984	168,879	161,145	153,765	133,760	123,243	112,948	103,185	93,946	85,272	77,176	69,658	62,706	56,298	50,408	45,010	39,315
12	Cumulative Revenue		439,866	222,111	666,419	897,503	1,133,208	1,373,628	1,618,856	1,846,888	2,071,478	2,291,500	2,506,365	2,715,480	2,918,375	3,114,669	3,304,058	3,486,300	3,661,200	3,828,603	3,988,384	4,137,570
13	PV of Cumulative Revenue		398,089	194,380	379,858	556,842	725,721	886,866	1,040,631	1,174,391	1,297,634	1,410,581	1,513,767	1,607,713	1,692,985	1,770,161	1,839,819	1,902,525	1,958,823	2,009,231	2,054,241	2,093,555
14	PV of Revenue Collected	Sum of Line 11	2,297,264																			
15																						
16																						
17	Monthly Rate, Escalated at 2% annually and then COS based beyond Contract Term		18,146	18,509	18,879	19,257	19,642	20,035	20,436	19,003	18,716	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
18	Annual Volumetric Contract Rate ($/GJ)	Line 10 / Line 30 / 1000	**3.629**	**3.702**	**3.776**	**3.851**	**3.928**	**4.007**	**4.087**	**3.801**	**3.743**	**3.667**	**3.581**	**3.485**	**3.382**	**3.272**	**3.156**	**3.037**	**2.915**	**2.790**	**2.663**	**2.486**
19																						
20	Annual Cost of Service (excl O&M)	Schedule 10, Line 2 x 1000	256,987	210,177	221,539	227,338	230,393	231,250	230,346	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
21	Annual Difference (Cost of Service - Contract Rate)	Line 20 - Line 10	39,231	(11,933)	(5,014)	(3,746)	(5,313)	(9,170)	(14,882)	-	-	-	-	-	-	-	-	-	-	-	-	-
22																						
23	**Cost of Service (O&M)**																					
24	Forecast Annual BC CPI Rate	CPI BC Stats Canada	1.99%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%
25	Annual O&M Expense	Schedule 1, Line 3 x 1000	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
26																						
27	Monthly Rate, Escalated at CPI annually	Line 25 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
28	Annual O&M Volumetric Contract Rate ($/GJ)	Line 25 / Line 30 / 1000	**0.833**	**0.850**	**0.868**	**0.885**	**0.903**	**0.921**	**0.940**	**0.959**	**0.979**	**0.999**	**1.019**	**1.040**	**1.061**	**1.082**	**1.104**	**1.127**	**1.149**	**1.173**	**1.197**	**1.221**
29																						
30	Annual Volume (TJ)	Minimum contract demand	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
31																						
32	Cost of Service (excl O&M) Volumetric Contract Rate ($/GJ)	Line 18	3.629	3.702	3.776	3.851	3.928	4.007	4.087	3.801	3.743	3.667	3.581	3.485	3.382	3.272	3.156	3.037	2.915	2.790	2.663	2.486
33	O&M Volumetric Contract Rate ($/GJ)	Line 28	0.833	0.850	0.868	0.885	0.903	0.921	0.940	0.959	0.979	0.999	1.019	1.040	1.061	1.082	1.104	1.127	1.149	1.173	1.197	1.221
34	Annual Overhead Allocation Charge ($/GJ)	[3]	0.200	0.204	0.208	0.212	0.217	0.221	0.226	0.230	0.235	0.240	0.245	0.249	0.255	0.260	0.265	0.270	0.276	0.281	0.287	0.293
35	**Total Annual Volumetric Contract Rate ($/GJ]**	Sum of Line 32 to Line 34	**4.663**	**4.756**	**4.852**	**4.949**	**5.048**	**5.150**	**5.253**	**4.990**	**4.957**	**4.905**	**4.844**	**4.774**	**4.697**	**4.613**	**4.526**	**4.434**	**4.340**	**4.244**	**4.147**	**4.000**
36	**Annual Forecast Revenue**	(Line 30 x Line 35) x 1000	**279,755**	**285,369**	**291,096**	**296,937**	**302,895**	**308,973**	**315,173**	**299,398**	**297,404**	**294,314**	**290,665**	**286,455**	**281,803**	**276,805**	**271,535**	**266,055**	**260,414**	**254,653**	**248,802**	**240,015**
37																						
38	**Contract Termination**[4]																					
39																						
40	Deferral Account Repayment	Schedule 9, Line 37	39,231	30,003	27,059	25,179	21,602	13,922	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Residual Asset Value	[5]	1,790,238	1,695,475	1,600,712	1,505,949	1,411,186	1,316,423	1,221,660	1,126,897	1,032,134	937,371	842,608	747,845	653,082	558,320	463,557	368,794	274,031	179,268	84,505	(258)
42	Add: Removal Costs	[5]																				
43	Less: Excess Fueling Station Recoveries	[6]	-	-	-	(120,960)	(244,320)	(370,160)	(498,560)	(622,120)	(745,560)	(868,440)	(990,600)	(1,111,880)	(1,232,120)	(1,351,240)	(1,469,120)	(1,585,760)	(1,701,080)	(1,815,040)	(1,927,680)	(2,037,960)
44	Total	Sum of Lines 40 to Line 43	1,829,470	1,725,479	1,627,771	1,652,088	1,677,108	1,700,505	1,720,220	1,749,017	1,777,694	1,805,811	1,833,208	1,859,725	1,885,202	1,909,560	1,932,677	1,954,554	1,975,111	1,994,308	2,012,185	2,037,702
45	Approximate Contract Termination Fee ($)		1,829,470	1,725,479	1,627,771	1,652,088	1,677,108	1,700,505	1,720,220	1,749,017	1,777,694	-	-	-	-	-	-	-	-	-	-	-
46																						

47 1- Line 3 /sum of [(1+2%) ^ year / (1+WACC) ^ year] for each year of the contract
48 2- Previous Year x (1+ 2%); in 2019+, Line 20
49 3- Previous Year x (1+ BC CPI)
50 4- The forecast early termination fee has been calculated on a year end basis. The actual fee would be determined at the time of contract termination and may be different than the amount shown on Line 45. Reference to Section 12B.5, Clause 11.1 of Appendix B in BFI Application
51 5- Schedule 5, (Line 3 + Line 6+ Line 9+ Line 12+ Line 15 + Schedule 8 Line 55) x 1000
52 6- Termination Fee tab, Line 6

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C): Discounted Cash Flow Analysis
Appendix D - Schedule 12
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cash Flow**																					
2	Add: Revenue	Schedule 11, Line 36	280	285	291	297	303	309	315	299	297	294	291	286	282	277	272	266	260	255	249	240
3	Less: O&M, Property Tax Expense	Schedule 1, - (Line 3 + Line 4)	(67)	(69)	(72)	(74)	(75)	(77)	(78)	(80)	(81)	(83)	(85)	(86)	(88)	(89)	(91)	(93)	(95)	(97)	(98)	(100)
4	EBITDA[1]	Line 2 + Line 3	212	217	219	223	228	232	237	220	216	211	206	200	194	187	180	173	166	158	150	140
5	Capital Expenditures[2]	Schedule 6, Line 25 + Line 29	(1,861)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
6	Pre-Tax Cash Flow	Line 4 + Line 5	(1,648)	217	219	223	228	232	237	220	216	211	206	200	194	187	180	173	166	158	150	130
7	Income Tax Expense	Line 4 x (- Schedule 3, Line 13)	(53)	(54)	(55)	(56)	(57)	(58)	(59)	(55)	(54)	(53)	(52)	(50)	(49)	(47)	(45)	(43)	(41)	(40)	(38)	(35)
8	Overhead Capitalized Tax Shield	Schedule 3, -Line 8 x Line 13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	CCA Tax Shield/Removal Cost	Schedule 3, (-Line 9 + Line 10) x Schedule 3, Line 13	39	70	57	47	38	31	26	21	18	15	12	10	9	7	6	6	5	4	4	6
10	Terminal Value of CCA Tax Shield	[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
11	Terminal Value	[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Free Cash Flow	Line 6 + Line 7	(1,663)	233	221	214	209	205	203	186	180	173	167	161	154	148	142	135	129	123	117	119
14																						
15	After Tax WACC %	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
16	Present Value of Free Cash Flow [3]	Line 13 / (1 + Line 15)^Yr	(1,675)	204	181	164	150	138	127	109	99	89	80	72	65	58	52	47	42	37	33	31
17	Total Present Value of Free Cash Flow	Sum of Line 16	**101**																			
18																						
19	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)																					
20	2- Net of CIAC and removal costs (if applicable) and excludes capitalized overhead																					
21	3- 2012 present value calculates capital expenditure to occur at time zero																					
22	4- [Class 8 UCC Closing Balance x CCA Rate / (CCA Rate + WACC) + Class 1.3 UCC Closing Balance x CCA Rate / (CCA Rate + WACC)] x Income Tax Rate																					
23	5- Evaluation period reflects the useful life of the assets, therefore it is assumed that the terminal value is zero																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (C)

CNG BFI Cost of Service: Approximate Contract Termination Fee
Appendix B - Section 12B.5, Clause 11.1
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Total Gross Plant in Service, Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
2	Accumulated Depreciation, Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
3	Net Salvage, Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
4	Deferral Account Repayment	Schedule 9, Line 37	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Add: Removal Costs[1]																					
6	Less: Excess Fueling Station Recoveries[2]		-	-	-	(121)	(244)	(370)	(499)	(622)	(746)	(868)	(991)	(1,112)	(1,232)	(1,351)	(1,469)	(1,586)	(1,701)	(1,815)	(1,928)	(2,038)
7	Total	Sum of Line 1 to Line 6	1,829	1,725	1,628	1,410	1,188	960	723	505	287	69	(148)	(364)	(579)	(793)	(1,006)	(1,217)	(1,427)	(1,636)	(1,843)	(2,038)
8	**Net Termination Payment[3]**		**1,829**	**1,725**	**1,628**	**1,410**	**1,188**	**960**	**723**	**505**	**287**	**69**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9																						
10																						
11		O&M Rate	1.033	1.054	1.076	1.098	1.12	1.143	1.166	1.189	1.214	1.238	1.263	1.289	1.315	1.342	1.369	1.397	1.425	1.454	1.484	1.514
12		Capital Rate	1.815	1.851	1.888	1.926	1.964	2.003	2.044	1.9	1.872	1.834	1.791	1.743	1.691	1.636	1.578	1.519	1.458	1.395	1.332	1.243
13		Total Charge	**2.848**	**2.905**	**2.964**	**3.024**	**3.084**	**3.146**	**3.210**	**3.089**	**3.086**	**3.072**	**3.054**	**3.032**	**3.006**	**2.978**	**2.947**	**2.916**	**2.883**	**2.849**	**2.816**	**2.757**
14																						
15	Volume in Excess of Minimum Contract Demand		-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
16																						
17	1- Actual removal costs to be determined at time of contract termination and will be less the net salvage collected to date																					
18	2- Cumulative fueling station recoveries received from volumes in excess of minimum contract demand																					
19	3- Excess fueling station recoveries will be credited to a maximum amount of the net book value of the assets. That is, the net termination payment cannot be negative.																					

FortisBC Energy Inc.

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Revenue Requirement

Appendix D - Schedule 1

($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Revenue Requirement**																					
2	Cost of Energy Sold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	Schedule 2, Line 19	50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
4	Property Taxes	Schedule 2, Line 29	17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
5	Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
6	Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
7	Amortization Expense	Schedule 9, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	Schedule 2, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	Schedule 3, Line 20	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
10	Earned Return	Schedule 5, Line 27	142	138	130	123	115	108	100	93	85	78	70	63	55	48	40	33	25	18	10	3
11																						
12	**Annual Revenue Requirement**	Sum of Lines 2 through 10	**307**	**261**	**274**	**280**	**285**	**287**	**287**	**286**	**283**	**280**	**276**	**271**	**267**	**261**	**256**	**250**	**244**	**238**	**232**	**222**

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): O&M, Other Revenue and Property Tax
Appendix D - Schedule 2
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross O&M**																					
2	Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																						
4	Vehicle Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Employee Expenses		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Materials & Supplies		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Computer Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Fees & Administrations Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contractor Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
10	Facilities		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Recoveries & Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Non-Labour Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
14																						
15	Total Gross O&M Expenses		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
16																						
17	(Less): Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Add (Less): Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
20																						
21	**Other Revenue**																					
22	Environmental Credits		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Property Taxes**																					
27	General, School and Other		17	18	18	18	19	19	19	20	20	21	21	22	22	22	23	23	24	24	25	25
28	1% in Lieu of General Municipal Tax[1]	Schedule 11, Line 36/1000 x 1%	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
29	Total Property Taxes		17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
30																						
31	1- Calculation is based on the second preceeding year; ex., 2012 is based on 2010 revenue																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Income Tax Expense
Appendix D - Schedule 3
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Income Tax Expense**																					
2																						
3	Earned Return	Schedule 5, Line 27	142	138	130	123	115	108	100	93	85	78	70	63	55	48	40	33	25	18	10	3
4	Deduct: Interest on debt	Schedule 5, Line 26	(74)	(72)	(68)	(64)	(60)	(56)	(52)	(48)	(44)	(40)	(37)	(33)	(29)	(25)	(21)	(17)	(13)	(9)	(5)	(2)
5	Add (Deduct): Amortization Expense	Schedule 9, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
7	Add: Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	Deduct: Overhead Capitalized Expensed for Tax Purposes		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct Removal Costs	Schedule 8, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
10	Deduct: Capital Cost Allowance	Schedule 4, Line 29	(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
11	Taxable Income After Tax	Sum of Lines 3 through 10	8	(120)	(71)	(33)	(2)	22	40	55	65	74	79	84	86	88	88	88	88	86	85	73
12																						
13	Income Tax Rate		25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
14	1 - Current Income Tax Rate	1 - Line 13	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
15																						
16	Taxable Income	Line 11 / Line 14	11	(160)	(95)	(43)	(3)	29	54	73	87	98	106	111	115	117	118	118	117	115	113	98
17																						
18	Total Income Tax Expense	Line 16 x Line 13	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
19	Adjustments		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Net Tax Expense	Line 18 + Line 19	3	(40)	(24)	(11)	(1)	7	13	18	22	25	26	28	29	29	29	29	29	29	28	24
21																						
22	Loss Carry-forward	Loss Carry-forward doesn't apply																				
23	Opening Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Loss Carry-forward		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Loss Utilization		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Closing Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Capital Cost Allowance
Appendix D - Schedule 4
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**CNG Dispensing Equipment- Class 8 @ 20%**																					
2	Opening Balance	Preceeding Year, Line 5	-	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22
3	Additions	Schedule 7 , Line 11 - AFUDC	1,376	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(138)	(248)	(198)	(158)	(127)	(101)	(81)	(65)	(52)	(42)	(33)	(27)	(21)	(17)	(14)	(11)	(9)	(7)	(6)	(4)
5	Closing Balance	Sum of Lines 2 through 4	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22	18
6																						
7	**Foundation- Class 1.3 @ 6%**																					
8	Opening Balance	Preceeding Year, Line 11	-	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141
9	Additions	Schedule 7 , Line 12 - AFUDC	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(13)	(26)	(24)	(23)	(21)	(20)	(19)	(18)	(17)	(16)	(15)	(14)	(13)	(12)	(12)	(11)	(10)	(10)	(9)	(8)
11	Closing Balance	Sum of Lines 8 through 10	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141	132
12																						
13	**NG Dehydrator- Class 8 @ 20%**																					
14	Opening Balance	Preceeding Year, Line 17	-	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1
15	Additions	Schedule 7 , Line 13 - AFUDC	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(4)	(8)	(6)	(5)	(4)	(3)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
17	Closing Balance	Sum of Lines 14 through 16	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1	1
18																						
19																						
20	**Capitalized Overhead- Class 0 @ 0%**																					
21	Opening Balance	Preceeding Year, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Additions	Schedule 2 , Line 17 x 0 / 0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	CCA	[Line 21 + (Line 22 x 1/2)] x CCA Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Closing Balance	Sum of Lines 21 through 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Total CCA**																					
27	Opening Balance	Preceeding Year, Line 30	-	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164
28	Additions	[1]	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	CCA		(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
30	Closing Balance	Sum of Lines 27 through 29	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164	151
31																						
32	1- Schedule 7 , Line 19 - Line 18, + Line 22 above - AFUDC																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Rate Base
Appendix D - Schedule 5
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Rate Base**																					
2	Gross Plant In Service- Beginning	Schedule 7, Line 10	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
3	Gross Plant In Service- Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
4																						
5	Accumulated Depreciation- Beginning	Schedule 8, Line 10	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
6	Accumulated Depreciation- Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
7																						
8	Contributions in Aid of Construction- Beginning	Schedule 7, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contributions in Aid of Construction- Ending	Schedule 7, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10																						
11	Negative Salvage - Beginning	Schedule 8, Line 53	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
12	Negative Salvage - Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
13																						
14	Accumulated Amortization- Beginning	Schedule 8, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	Schedule 8, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17	Net Plant in Service, Mid-Year	Sum (Lines 2 through 15)/2	895	1,743	1,648	1,553	1,459	1,364	1,269	1,174	1,080	985	890	795	700	606	511	416	321	227	132	42
18																						
19	Adjustment to 13-month average	[1]	900	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	Schedule 9, Line 58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	[2]	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
22	**Total Rate Base**	**Sum of Lines 17 through 21**	**1,792**	**1,739**	**1,644**	**1,550**	**1,455**	**1,360**	**1,265**	**1,171**	**1,076**	**981**	**886**	**791**	**697**	**602**	**507**	**412**	**318**	**223**	**128**	**38**
23																						
24	**Return on Rate Base**																					
25	Equity Return	Line 22 x ROE x Equity %	68	66	62	59	55	52	48	44	41	37	34	30	26	23	19	16	12	8	5	1
26	Debt Component	[3]	74	72	68	64	60	56	52	48	44	40	37	33	29	25	21	17	13	9	5	2
27	Total Earned Return	Line 25 + Line 26	**142**	**138**	**130**	**123**	**115**	**108**	**100**	**93**	**85**	**78**	**70**	**63**	**55**	**48**	**40**	**33**	**25**	**18**	**10**	**3**
28	Return on Rate Base %	Line 27 / Line 22	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
29																						
30	1- [Schedule 7, (Line 19 + Line 42) + Schedule 8, (Line 19+ Line 42)] x (Days In-service/365-1/2)																					
31	2- Schedule 7, Line 37 x FEI CWC/Closing GPIS %																					
32	3- Line 22 x (LTD Rate x LTD% + STD Rate x STD %)																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Capital Spending
Appendix D - Schedule 6
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Capital Spending Prior to 2012																					
2	CNG Dispensing Equipment		1,376																			
3	Foundation		442																			
4	NG Dehydrator		43																			
5	Total Capital Spending Prior to 2012	Sum of Lines 2 through 4	1,861																			
6																						
7	AFUDC Prior to 2012																					
8	CNG Dispensing Equipment		24																			
9	Foundation		-																			
10	NG Dehydrator		1																			
11	Total AFUDC Prior to 2012	Sum of Lines 8 through 10	25																			
12																						
13	Capital Spending 2012 Onwards																					
14	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Capital Spending 2012 Onwards	Sum of Lines 14 through 16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																						
19	AFUDC 2012 Onwards																					
20	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total AFUDC 2012 Onwards	Sum of Lines 20 through 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																						
25	Total Capital Spending[1]	Line 5 + Line 17	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total AFUDC	Line 11 + Line 23	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Total Annual Capital Spending and AFUDC	Line 25 + Line 26	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28																						
29	Contributions in Aid of Construction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
31	Net Annual Project Costs- Capital	Line 27 + Line 29 + Line 30	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
32																						
33	Total Project Costs- Capital Spending and AFUDC	Sum of Line 27	**1,885**																			
34	Total Net Project Costs- including CIAC & Removal Costs	Sum of Line 31	**1,895**																			
35																						
36	1- Excluding capitalized overhead; First year of analysis includes all prior year spending																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Gross Plant in Service & Contributions in Aid of Construction
Appendix D - Schedule 7
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross Plant in Service**																					
2																						
3	Gross Plant in Service, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
5	Foundation	Preceeding Year, Line 32	-	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
6	NG Dehydrator	Preceeding Year, Line 33	-	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 9	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
11																						
12	Gross Plant in Service, Additions																					
13	CNG Dispensing Equipment	Schedule 6, Lines 2 + 8 + 14 + 20	1,400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Foundation	Schedule 6, Lines 3 + 9 + 15 + 21	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	NG Dehydrator	Schedule 6, Lines 4 + 10 + 16 + 22	44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17																						
18	Capitalized Overhead	Schedule 2, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Gross Plant in Service, Additions	Sum of Lines 13 through 18	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																						
21	Gross Plant in Service, Retirements																					
22	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Gross Plant in Service, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Gross Plant in Service, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
32	Foundation	Line 5 + Line 14 + Line 23	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
33	NG Dehydrator	Line 6 + Line 15 + Line 24	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Gross Plant in Service, Ending	Sum of Lines 31 through 36	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
38																						
39																						
40	**Contributions in Aid of Construction (CIAC)**																					
41	CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Accumulated Depreciation & Amortization
Appendix D - Schedule 8
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Accumulated Depreciation**																					
2																						
3	Accumulated Depreciation, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)
5	Foundation	Preceeding Year, Line 32	-	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)
6	NG Dehydrator	Preceeding Year, Line 33	-	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 9	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
11																						
12	Accumulated Depreciation, Depreciation Expense[1]																					
13	CNG Dispensing Equipment@ 5%	Schedule 7, Line 4 & Line 13	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
14	Foundation@ 5%	Schedule 7, Line 5 & Line 14	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
15	NG Dehydrator@ 5%	Schedule 7, Line 6 & Line 15	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
16																						
17																						
18	Capitalized Overhead@ 0%	Schedule 7, Line 9 & Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Accumulated Depreciation, Depreciation Expe	Sum of Lines 13 through 18	(95)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)
20																						
21	Accumulated Depreciation, Retirements																					
22	CNG Dispensing Equipment	Schedule 7, Line 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation	Schedule 7, Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator	Schedule 7, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead	Schedule 7, Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Accumulated Depreciation, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Accumulated Depreciation, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)	(1,400)
32	Foundation	Line 5 + Line 14 + Line 23	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)	(442)
33	NG Dehydrator	Line 6 + Line 15 + Line 24	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)	(44)
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Accumulated Depreciation, Ending	Sum of Lines 31 through 36	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
38																						
39																						
40	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**																					
41	Accumulated Amortization CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Amortization	[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Accumulated Amortization CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45																						
46	**Removal Cost Provision**																					
47	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Foundation	-Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
49	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Total Removal Cost Provision	Sum of Lines 47 through 49	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
51																						
52	**Negative Salvage Continuity - Foundation**																					
53	Opening Balance	Preceeding Year, Line 56	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
54	Provision (Cr.) [2]	Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
55	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
56	Ending Balance	Sum of Lines 53 through 55	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
57																						

58 1- Depreciation & Amortization Expense calculation is based on opening balance + (additions x in-service days/365 if it is the in-service year for project/; otherwise, additions x 1/2)
59 2- Annual Salvage Rate calculation is 0.11% based on (foundation costs / removal costs / retirement years

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Deferred Charges & Deficiency / Surplus [Tracker]
Appendix D - Schedule 9
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	*Deferred Charge- O&M*																					
2	Opening Balance	Previous Year, Line 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	Line 3 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	(Lines 2 + 3 + 4) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	Sum of Lines 3 through 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Closing Balance	Lines 2 + 6 + 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																						
10	*Deferred Charge- Property Tax*																					
11	Opening Balance	Previous Year, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	Line 12 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	(Lines 11 + 12 + 13) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	Sum of Lines 12 through 14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	Lines 11 + 15 + 16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																						
19	*Deferred Charge- (Gain)/Loss on Asset Disposal*																					
20	Opening Balance	Previous Year, Line 26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Tax	Line 21 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	AFUDC	(Lines 20 + 21 + 22) x Schedule 10, Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Net Additions	Sum of Lines 21 through 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Amortization Expense @ years		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Closing Balance	Lines 20 + 24 + 25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27																						
28	**Deficiency / Surplus [Tracker]**																					
29	Opening Balance	Previous Year, Line 37	-	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gross Addition	Schedule 11, Line 21	39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Net Addition	Line 30 + Line 31	39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
33	AFUDC																					
34	Equity	(Line 29) x (Schedule 10, Lines 8 x 9)	-	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Debt	[1]	-	1	1	1	1	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Interest Adjustment	[2]	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Closing Balance	Sum of Lines 32 through 36	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38																						
39	**Deferred Charge- Non Rate Base**																					
40	Opening Balance	Previous Year, Line 47	-	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Opening Balance, Adjustment	Opening balance transfer to rate base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Gross Additions		39	(12)	(5)	(4)	(5)	(9)	(15)	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	AFUDC		-	3	2	2	2	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
45	Net Additions	Sum of Lines 42 through 44	39	(9)	(3)	(2)	(4)	(8)	(14)	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Closing Balance	Lines 40 + 41 + 45 + 46	39	30	27	25	22	14	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-
48																						
49	**Deferred Charge- Rate Base**																					
50	Opening Balance	Previous Year, Line 57	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Closing Balance	Line 50 + Line 54 + Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57																						
58	Deferred Charge, Mid-Year	(Line 50+ Line 51 + Line 56) / 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59																						
60	1- (Line 29) x [Schedule 10 , (Lines 11 x 12+ Lines 13 x 14) x (1- Tax Rate)]																					
61	2- Adjustment to net account to zero in final year; result of varying WACC rates throughout contract																					

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Present Value of Revenue Requirement
Appendix D - Schedule 10
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1																						
2	Annual Revenue Requirement (Excluding O&M)	Schedule 1, Line 12 -Line 3	257.0	210.2	221.5	227.3	230.4	231.2	230.3	228.0	224.6	220.0	214.9	209.1	202.9	196.3	189.4	182.2	174.9	167.4	159.8	149.2
3	Annual Number of Customers		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	Annual Revenue Requirement (O&M)	Schedule 1, Line 3	50.0	51.0	52.1	53.1	54.2	55.3	56.4	57.6	58.7	59.9	61.1	62.4	63.6	64.9	66.2	67.6	69.0	70.4	71.8	73.2
5																						
6	**Annual Discount Rate**																					
7	Equity Component																					
8	ROE %		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
9	Equity Portion		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
10	Debt Component																					
11	Long Term Debt Rate		6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%
12	Long Term Debt Portion		58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%
13	Short Term Debt Rate		4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
14	Short Term Debt Portion		1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%
15																						
16	Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Pre- Tax Weighted Average Cost of Capital (WACC)[1]		9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
18	After- Tax Weighted Average Cost of Capital (WACC)[2]		6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
19																						
20	**Present Value of Revenue Requirement**																					
21	PV of Annual Cost of Service (excl O&M) Revenue Requirement	Line 2 / (1 + Line 18)^Yr	240.4	183.9	181.4	174.1	165.1	155.0	144.4	133.8	123.2	112.9	103.2	93.9	85.3	77.2	69.7	62.7	56.3	50.4	45.0	39.3
22	PV of Annual Revenue Requirement ($/Mnth)		20	15	15	15	14	13	12	11	10	9	9	8	7	6	6	5	5	4	4	3
23	Total PV of Cost of Service (excl O&M)	Sum of Line 21	2,297.3																			
24	Total PV of Cost of Service (excl O&M) over contract term		1,244.3																			
25	PV of Annual O&M	Line 4 / (1 + Line 18)^Yr	46.8	44.6	42.6	40.7	38.8	37.1	35.4	33.8	32.2	30.8	29.4	28.0	26.7	25.5	24.4	23.3	22.2	21.2	20.2	19.3
26	Total PV of O&M	Sum of Line 25	622.9																			
27	Total PV of O&M over contract term		286.0																			
28																						
29	PV of Annual Customers	Line 3 / (1 + Line 18)^Yr	0.9	0.9	0.8	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
30	Total PV of Customers	Sum of Line 29	10.6																			
31																						
32																						
33	**Tariff Analysis**																					
34	Annual Volume (TJ)		60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
35																						
36	**Cost of Service (excluding O&M)**																					
37	Annual Cost of Service per Customer ($/Yr)	Line 2 x 1000 / Line 3	256,987	210,177	221,539	227,338	230,393	231,250	230,346	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
38	Monthly Cost of Service per Customer ($/Mnth)	Line 37 / 12	21,416	17,515	18,462	18,945	19,199	19,271	19,196	19,003	18,716	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
39	Annual Volumetric Cost of Service ($/GJ)	Line 2 / Line 34	4.283	3.503	3.692	3.789	3.840	3.854	3.839	3.801	3.743	3.667	3.581	3.485	3.382	3.272	3.156	3.037	2.915	2.790	2.663	2.486
40																						
41	**O&M**																					
42	Annual Cost of Service per Customer ($/Yr)	Line 4 x 1000 / Line 3	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
43	Monthly Cost of Service per Customer ($/Mnth)	Line 42 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
44	Annual Volumetric Cost of Service ($/GJ)	Line 4 / Line 34	0.833	0.850	0.868	0.885	0.903	0.921	0.940	0.959	0.979	0.999	1.019	1.040	1.061	1.082	1.104	1.127	1.149	1.173	1.197	1.221
45																						
46	**Levelized Tariff Analysis**																					
47	PV of Annual Volume (TJ)	Line 34 / (1 + Line 18)^Yr	56.1	52.5	49.1	46.0	43.0	40.2	37.6	35.2	32.9	30.8	28.8	27.0	25.2	23.6	22.1	20.6	19.3	18.1	16.9	15.8
48	Total PV of Volume (TJ)	Sum of Line 47	640.8																			
49																						
50	Levelized Annual Delivery Charge per Customer ($/Yr)	Line 23 x 1000 / Line 30	**274,315**																			
51	Levelized Monthly Delivery Charge per Customer ($/Mnth)	Line 50 / 12	**22,860**																			
52	Levelized Volumetric Delivery Rate ($/GJ)	(Line 23 + Line 26) / Line 48	**4.557**																			
53																						
54	1- (Line 8 x Line 9) / 1- Line 16 + (Line 11 x Line 12 + Line 13 x Line 14)																					
55	2- Line 9 x Line 10 + [(Line 12 x Line 13 + Line 14 x Line 15) x 1- Line 17]																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Contract Rate Design
Appendix D - Schedule 11
($), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cost of Service (Excluding O&M)**																					
2	Required Delivery Revenue ($) (discounted) - 20 years	Schedule 10, Line 23 x 1000	2,297,264																			
3	Required Delivery Revenue ($) (discounted, contract term) - 7 yrs	Schedule 10, Line 24 x 1000	1,244,340																			
4	Flat Rate for 20 Years		274,315																			
5																						
6	Year 1 Contract Rate, Escalated at 2% Annually	[1]	217,755																			
7	Annual Contract Rate Escalation		2.00%																			
8																						
9	Annual Discount Rate (After- Tax WACC)	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
10	Annual Contract Rate	[2]	217,755	222,111	226,553	231,084	235,706	240,420	245,228	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
11	PV of Annual Contract Rate	Line 10 / (1 + Line 9)^Yr	203,709	194,380	185,478	176,984	168,879	161,145	153,765	133,760	123,243	112,948	103,185	93,946	85,272	77,176	69,658	62,706	56,298	50,408	45,010	39,315
12	Cumulative Revenue		439,866	222,111	666,419	897,503	1,133,208	1,373,628	1,618,856	1,846,888	2,071,478	2,291,500	2,506,365	2,715,480	2,918,375	3,114,669	3,304,058	3,486,300	3,661,200	3,828,603	3,988,384	4,137,570
13	PV of Cumulative Revenue		398,089	194,380	379,858	556,842	725,721	886,866	1,040,631	1,174,391	1,297,634	1,410,581	1,513,767	1,607,713	1,692,985	1,770,161	1,839,819	1,902,525	1,958,823	2,009,231	2,054,241	2,093,555
14	PV of Revenue Collected	Sum of Line 11	2,297,264																			
15																						
16																						
17	Monthly Rate, Escalated at 2% annually and then COS based beyond Contract Term		18,146	18,509	18,879	19,257	19,642	20,035	20,436	19,003	18,716	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
18	Annual Volumetric Contract Rate ($/GJ)	Line 10 / Line 30 / 1000	**3.629**	**3.702**	**3.776**	**3.851**	**3.928**	**4.007**	**4.087**	**3.801**	**3.743**	**3.667**	**3.581**	**3.485**	**3.382**	**3.272**	**3.156**	**3.037**	**2.915**	**2.790**	**2.663**	**2.486**
19																						
20	Annual Cost of Service (excl O&M)	Schedule 10, Line 2 x 1000	256,987	210,177	221,539	227,338	230,393	231,250	230,346	228,033	224,590	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
21	Annual Difference (Cost of Service - Contract Rate)	Line 20 - Line 10	39,231	(11,933)	(5,014)	(3,746)	(5,313)	(9,170)	(14,882)	-	-	-	-	-	-	-	-	-	-	-	-	-
22																						
23	**Cost of Service (O&M)**																					
24	Forecast Annual BC CPI Rate	CPI BC Stats Canada	1.99%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%
25	Annual O&M Expense	Schedule 1, Line 3 x 1000	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
26																						
27	Monthly Rate, Escalated at CPI annually	Line 25 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
28	Annual O&M Volumetric Contract Rate ($/GJ)	Line 25 / Line 30 / 1000	**0.833**	**0.850**	**0.868**	**0.885**	**0.903**	**0.921**	**0.940**	**0.959**	**0.979**	**0.999**	**1.019**	**1.040**	**1.061**	**1.082**	**1.104**	**1.127**	**1.149**	**1.173**	**1.197**	**1.221**
29																						
30	Annual Volume (TJ)	Minimum contract demand	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
31																						
32	Cost of Service (excl O&M) Volumetric Contract Rate ($/GJ)	Line 18	3.629	3.702	3.776	3.851	3.928	4.007	4.087	3.801	3.743	3.667	3.581	3.485	3.382	3.272	3.156	3.037	2.915	2.790	2.663	2.486
33	O&M Volumetric Contract Rate ($/GJ)	Line 28	0.833	0.850	0.868	0.885	0.903	0.921	0.940	0.959	0.979	0.999	1.019	1.040	1.061	1.082	1.104	1.127	1.149	1.173	1.197	1.221
34	Annual Overhead Allocation Charge ($/GJ)	[3]	0.200	0.204	0.208	0.212	0.217	0.221	0.226	0.230	0.235	0.240	0.245	0.249	0.255	0.260	0.265	0.270	0.276	0.281	0.287	0.293
35	**Total Annual Volumetric Contract Rate ($/GJ]**	Sum of Line 32 to Line 34	**4.663**	**4.756**	**4.852**	**4.949**	**5.048**	**5.150**	**5.253**	**4.990**	**4.957**	**4.905**	**4.844**	**4.774**	**4.697**	**4.613**	**4.526**	**4.434**	**4.340**	**4.244**	**4.147**	**4.000**
36	**Annual Forecast Revenue**	(Line 30 x Line 35) x 1000	**279,755**	**285,369**	**291,096**	**296,937**	**302,895**	**308,973**	**315,173**	**299,398**	**297,404**	**294,314**	**290,665**	**286,455**	**281,803**	**276,805**	**271,535**	**266,055**	**260,414**	**254,653**	**248,802**	**240,015**
37																						
38	**Contract Termination**[4]																					
39																						
40	Deferral Account Repayment	Schedule 9, Line 37	39,231	30,003	27,059	25,179	21,602	13,922	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Residual Asset Value	[5]	1,790,238	1,695,475	1,600,712	1,505,949	1,411,186	1,316,423	1,221,660	1,126,897	1,032,134	937,371	842,608	747,845	653,082	558,320	463,557	368,794	274,031	179,268	84,505	(258)
42	Add: Removal Costs	[5]																				
43	Less: Excess Fueling Station Recoveries	[6]	-	-	-	-	-	(125,840)	(254,240)	(377,800)	(501,240)	(624,120)	(746,280)	(867,560)	(987,800)	(1,106,920)	(1,224,800)	(1,341,440)	(1,456,760)	(1,570,720)	(1,683,360)	(1,793,640)
44	Total	Sum of Lines 40 to Line 43	1,829,470	1,725,479	1,627,771	1,531,128	1,432,788	1,456,185	1,475,900	1,504,697	1,533,374	1,561,491	1,588,888	1,615,405	1,640,882	1,665,240	1,688,357	1,710,234	1,730,791	1,749,988	1,767,865	1,793,382
45	Approximate Contract Termination Fee ($)		1,829,470	1,725,479	1,627,771	1,531,128	1,432,788	1,456,185	1,475,900	1,504,697	1,533,374	-	-	-	-	-	-	-	-	-	-	-
46																						

47 1- Line 3 /sum of [(1+2%) ^ year / (1+WACC) ^ year] for each year of the contract
48 2- Previous Year x (1+ 2%); in 2019+, Line 20
49 3- Previous Year x (1+ BC CPI)
50 4- The forecast early termination fee has been calculated on a year end basis. The actual fee would be determined at the time of contract termination and may be different than the amount shown on Line 45. Reference to Section 12B.5, Clause 11.1 of Appendix B in BFI Application
51 5- Schedule 5, (Line 3 + Line 6+ Line 9+ Line 12+ Line 15 + Schedule 8 Line 55) x 1000
52 6- Termination Fee tab, Line 6

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D): Discounted Cash Flow Analysis
Appendix D - Schedule 12
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cash Flow**																					
2	Add: Revenue	Schedule 11, Line 36	280	285	291	297	303	309	315	299	297	294	291	286	282	277	272	266	260	255	249	240
3	Less: O&M, Property Tax Expense	Schedule 1, - (Line 3 + Line 4)	(67)	(69)	(72)	(74)	(75)	(77)	(78)	(80)	(81)	(83)	(85)	(86)	(88)	(89)	(91)	(93)	(95)	(97)	(98)	(100)
4	EBITDA[1]	Line 2 + Line 3	212	217	219	223	228	232	237	220	216	211	206	200	194	187	180	173	166	158	150	140
5	Capital Expenditures[2]	Schedule 6, Line 25 + Line 29	(1,861)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
6	Pre-Tax Cash Flow	Line 4 + Line 5	(1,648)	217	219	223	228	232	237	220	216	211	206	200	194	187	180	173	166	158	150	130
7	Income Tax Expense	Line 4 x (- Schedule 3, Line 13)	(53)	(54)	(55)	(56)	(57)	(58)	(59)	(55)	(54)	(53)	(52)	(50)	(49)	(47)	(45)	(43)	(41)	(40)	(38)	(35)
8	Overhead Capitalized Tax Shield	Schedule 3, -Line 8 x Line 13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	CCA Tax Shield/Removal Cost	Schedule 3, (-Line 9 + Line 10) x Schedule 3, Line 13	39	70	57	47	38	31	26	21	18	15	12	10	9	7	6	6	5	4	4	6
10	Terminal Value of CCA Tax Shield	[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
11	Terminal Value	[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Free Cash Flow	Line 6 + Line 7	(1,663)	233	221	214	209	205	203	186	180	173	167	161	154	148	142	135	129	123	117	119
14																						
15	After Tax WACC %	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
16	Present Value of Free Cash Flow [3]	Line 13 / (1 + Line 15)^Yr	(1,675)	204	181	164	150	138	127	109	99	89	80	72	65	58	52	47	42	37	33	31
17	Total Present Value of Free Cash Flow	Sum of Line 16	**101**																			
18																						
19	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)																					
20	2- Net of CIAC and removal costs (if applicable) and excludes capitalized overhead																					
21	3- 2012 present value calculates capital expenditure to occur at time zero																					
22	4- [Class 8 UCC Closing Balance x CCA Rate / (CCA Rate + WACC) + Class 1.3 UCC Closing Balance x CCA Rate / (CCA Rate + WACC)] x Income Tax Rate																					
23	5- Evaluation period reflects the useful life of the assets, therefore it is assumed that the terminal value is zero																					

FortisBC Energy Inc.
CNG BFI Cost of Service: BCUC IR 1.55.1 Scenario (D)

CNG BFI Cost of Service: Approximate Contract Termination Fee
Appendix B - Section 12B.5, Clause 11.1
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Total Gross Plant in Service, Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
2	Accumulated Depreciation, Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
3	Net Salvage, Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
4	Deferral Account Repayment	Schedule 9, Line 37	39	30	27	25	22	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Add: Removal Costs[1]																					
6	Less: Excess Fueling Station Recoveries[2]		-	-	-	-	-	(126)	(254)	(378)	(501)	(624)	(746)	(868)	(988)	(1,107)	(1,225)	(1,341)	(1,457)	(1,571)	(1,683)	(1,794)
7	Total	Sum of Line 1 to Line 6	1,829	1,725	1,628	1,531	1,433	1,205	967	749	531	313	96	(120)	(335)	(549)	(761)	(973)	(1,183)	(1,391)	(1,599)	(1,794)
8	**Net Termination Payment[3]**		**1,829**	**1,725**	**1,628**	**1,531**	**1,433**	**1,205**	**967**	**749**	**531**	**313**	**96**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9																						
10																						
11		O&M Rate	1.033	1.054	1.076	1.098	1.12	1.143	1.166	1.189	1.214	1.238	1.263	1.289	1.315	1.342	1.369	1.397	1.425	1.454	1.484	1.514
12		Capital Rate	1.815	1.851	1.888	1.926	1.964	2.003	2.044	1.9	1.872	1.834	1.791	1.743	1.691	1.636	1.578	1.519	1.458	1.395	1.332	1.243
13		Total Charge	**2.848**	**2.905**	**2.964**	**3.024**	**3.084**	**3.146**	**3.210**	**3.089**	**3.086**	**3.072**	**3.054**	**3.032**	**3.006**	**2.978**	**2.947**	**2.916**	**2.883**	**2.849**	**2.816**	**2.757**
14																						
15	Volume in Excess of Minimum Contract Demand		-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
16																						
17	1- Actual removal costs to be determined at time of contract termination and will be less the net salvage collected to date																					
18	2- Cumulative fueling station recoveries received from volumes in excess of minimum contract demand																					
19	3- Excess fueling station recoveries will be credited to a maximum amount of the net book value of the assets. That is, the net termination payment cannot be negative.																					

Attachment 55.2

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Revenue Requirement
Appendix D - Schedule 1
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Revenue Requirement**																					
2	Cost of Energy Sold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	Schedule 2, Line 19	50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
4	Property Taxes	Schedule 2, Line 29	17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
5	Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
6	Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
7	Amortization Expense	Schedule 9, Line 18	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	Schedule 2, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	Schedule 3, Line 20	1	(41)	(25)	(12)	(2)	6	12	18	22	25	26	28	29	29	29	29	29	29	28	24
10	Earned Return	Schedule 5, Line 27	143	140	132	124	116	108	101	93	85	78	70	63	55	48	40	33	25	18	10	3
11																						
12	**Annual Revenue Requirement**	Sum of Lines 2 through 10	**312**	**267**	**279**	**286**	**289**	**291**	**291**	**286**	**283**	**280**	**276**	**271**	**267**	**261**	**256**	**250**	**244**	**238**	**232**	**222**

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: O&M, Other Revenue and Property Tax
Appendix D - Schedule 2
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross O&M**																					
2	Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																						
4	Vehicle Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Employee Expenses		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Materials & Supplies		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Computer Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Fees & Administrations Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contractor Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
10	Facilities		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Recoveries & Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Non-Labour Costs		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
14																						
15	Total Gross O&M Expenses		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
16																						
17	(Less): Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Add (Less): Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M		50	51	52	53	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73
20																						
21	**Other Revenue**																					
22	Environmental Credits		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Property Taxes**																					
27	General, School and Other		17	18	18	18	19	19	19	20	20	21	21	22	22	22	23	23	24	24	25	25
28	1% in Lieu of General Municipal Tax[1]	Schedule 11, Line 36/1000 x 1%	-	-	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	2
29	Total Property Taxes		17	18	20	21	21	21	22	22	23	23	23	24	24	25	25	25	26	26	27	27
30																						
31	1- Calculation is based on the second preceeding year; ex., 2012 is based on 2010 revenue																					

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Income Tax Expense
Appendix D - Schedule 3
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Income Tax Expense**																					
2																						
3	Earned Return	Schedule 5, Line 27	143	140	132	124	116	108	101	93	85	78	70	63	55	48	40	33	25	18	10	3
4	Deduct: Interest on debt	Schedule 5, Line 26	(75)	(73)	(69)	(65)	(61)	(56)	(52)	(48)	(44)	(40)	(37)	(33)	(29)	(25)	(21)	(17)	(13)	(9)	(5)	(2)
5	Add (Deduct): Amortization Expense	Schedule 9, Line 18	(5)	(5)	(5)	(5)	(5)	(5)	(5)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 8, Line 19 + Line 42	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
7	Add: Removal Cost Provision	Schedule 8, Line 54	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	Deduct: Overhead Capitalized Expensed for Tax Purposes		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct Removal Costs	Schedule 8, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
10	Deduct: Capital Cost Allowance	Schedule 4, Line 29	(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
11	Taxable Income After Tax	Sum of Lines 3 through 10	3	(124)	(76)	(37)	(7)	17	35	55	65	74	79	84	86	88	88	88	88	86	85	73
12																						
13	Income Tax Rate		25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
14	1 - Current Income Tax Rate	1 - Line 13	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
15																						
16	Taxable Income	Line 11 / Line 14	4	(166)	(101)	(50)	(9)	22	47	73	87	98	106	111	115	117	118	118	117	115	113	98
17																						
18	Total Income Tax Expense	Line 16 x Line 13	1	(41)	(25)	(12)	(2)	6	12	18	22	25	26	28	29	29	29	29	29	29	28	24
19	Adjustments		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Net Tax Expense	Line 18 + Line 19	1	(41)	(25)	(12)	(2)	6	12	18	22	25	26	28	29	29	29	29	29	29	28	24
21																						
22	Loss Carry-forward	Loss Carry-forward doesn't apply																				
23	Opening Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Loss Carry-forward		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Loss Utilization		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Closing Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Capital Cost Allowance
Appendix D - Schedule 4
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**CNG Dispensing Equipment- Class 8 @ 20%**																					
2	Opening Balance	Preceeding Year, Line 5	-	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22
3	Additions	Schedule 7 , Line 11 - AFUDC	1,376	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(138)	(248)	(198)	(158)	(127)	(101)	(81)	(65)	(52)	(42)	(33)	(27)	(21)	(17)	(14)	(11)	(9)	(7)	(6)	(4)
5	Closing Balance	Sum of Lines 2 through 4	1,238	990	792	634	507	406	325	260	208	166	133	106	85	68	54	44	35	28	22	18
6																						
7	**Foundation- Class 1.3 @ 6%**																					
8	Opening Balance	Preceeding Year, Line 11	-	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141
9	Additions	Schedule 7 , Line 12 - AFUDC	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(13)	(26)	(24)	(23)	(21)	(20)	(19)	(18)	(17)	(16)	(15)	(14)	(13)	(12)	(12)	(11)	(10)	(10)	(9)	(8)
11	Closing Balance	Sum of Lines 8 through 10	429	403	379	356	335	315	296	278	261	246	231	217	204	192	180	169	159	150	141	132
12																						
13	**NG Dehydrator- Class 8 @ 20%**																					
14	Opening Balance	Preceeding Year, Line 17	-	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1
15	Additions	Schedule 7 , Line 13 - AFUDC	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(4)	(8)	(6)	(5)	(4)	(3)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
17	Closing Balance	Sum of Lines 14 through 16	39	31	25	20	16	13	10	8	6	5	4	3	3	2	2	1	1	1	1	1
18																						
19																						
20	**Capitalized Overhead- Class 0 @ 0%**																					
21	Opening Balance	Preceeding Year, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Additions	Schedule 2 , Line 17 x 0 / 0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	CCA	[Line 21 + (Line 22 x 1/2)] x CCA Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Closing Balance	Sum of Lines 21 through 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26	**Total CCA**																					
27	Opening Balance	Preceeding Year, Line 30	-	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164
28	Additions	[1]	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	CCA		(155)	(281)	(228)	(186)	(152)	(125)	(103)	(85)	(70)	(59)	(49)	(41)	(35)	(30)	(26)	(22)	(19)	(17)	(15)	(13)
30	Closing Balance	Sum of Lines 27 through 29	1,706	1,424	1,196	1,010	858	733	630	546	476	417	368	327	292	262	236	214	195	179	164	151
31																						
32	1- Schedule 7 , Line 19 - Line 18, + Line 22 above - AFUDC																					

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Rate Base
Appendix D - Schedule 5
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Rate Base**																					
2	Gross Plant In Service- Beginning	Schedule 7, Line 10	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
3	Gross Plant In Service- Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
4																						
5	Accumulated Depreciation- Beginning	Schedule 8, Line 10	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
6	Accumulated Depreciation- Ending	Schedule 8, Line 37	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
7																						
8	Contributions in Aid of Construction- Beginning	Schedule 7, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contributions in Aid of Construction- Ending	Schedule 7, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10																						
11	Negative Salvage - Beginning	Schedule 8, Line 53	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
12	Negative Salvage - Ending	Schedule 8, Line 56	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
13																						
14	Accumulated Amortization- Beginning	Schedule 8, Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	Schedule 8, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17	Net Plant in Service, Mid-Year	Sum (Lines 2 through 15)/2	895	1,743	1,648	1,553	1,459	1,364	1,269	1,174	1,080	985	890	795	700	606	511	416	321	227	132	42
18																						
19	Adjustment to 13-month average	[1]	900	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	Schedule 9, Line 21	16	29	24	19	13	8	3	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	[2]	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
22	**Total Rate Base**	**Sum of Lines 17 through 21**	**1,808**	**1,769**	**1,668**	**1,568**	**1,468**	**1,368**	**1,268**	**1,171**	**1,076**	**981**	**886**	**791**	**697**	**602**	**507**	**412**	**318**	**223**	**128**	**38**
23																						
24	**Return on Rate Base**																					
25	Equity Return	Line 22 x ROE x Equity %	69	67	63	60	56	52	48	44	41	37	34	30	26	23	19	16	12	8	5	1
26	Debt Component	[3]	75	73	69	65	61	56	52	48	44	40	37	33	29	25	21	17	13	9	5	2
27	Total Earned Return	Line 25 + Line 26	**143**	**140**	**132**	**124**	**116**	**108**	**101**	**93**	**85**	**78**	**70**	**63**	**55**	**48**	**40**	**33**	**25**	**18**	**10**	**3**
28	Return on Rate Base %	Line 27 / Line 22	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
29																						
30	1- [Schedule 7, (Line 19 + Line 42) + Schedule 8, (Line 19+ Line 42)] x (Days In-service/365-1/2)																					
31	2- Schedule 7, Line 37 x FEI CWC/Closing GPIS %																					
32	3- Line 22 x (LTD Rate x LTD% + STD Rate x STD %)																					

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Capital Spending
Appendix D - Schedule 6
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Capital Spending Prior to 2012																					
2	CNG Dispensing Equipment		1,376																			
3	Foundation		442																			
4	NG Dehydrator		43																			
5	Total Capital Spending Prior to 2012	Sum of Lines 2 through 4	1,861																			
6																						
7	AFUDC Prior to 2012																					
8	CNG Dispensing Equipment		24																			
9	Foundation		-																			
10	NG Dehydrator		1																			
11	Total AFUDC Prior to 2012	Sum of Lines 8 through 10	25																			
12																						
13	Capital Spending 2012 Onwards																					
14	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Capital Spending 2012 Onwards	Sum of Lines 14 through 16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																						
19	AFUDC 2012 Onwards																					
20	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total AFUDC 2012 Onwards	Sum of Lines 20 through 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																						
25	Total Capital Spending[1]	Line 5 + Line 17	1,861	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total AFUDC	Line 11 + Line 23	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Total Annual Capital Spending and AFUDC	Line 25 + Line 26	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28																						
29	Contributions in Aid of Construction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
31	Net Annual Project Costs- Capital	Line 27 + Line 29 + Line 30	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
32																						
33	Total Project Costs- Capital Spending and AFUDC	Sum of Line 27	**1,885**																			
34	Total Net Project Costs- including CIAC & Removal Costs	Sum of Line 31	**1,895**																			
35																						
36	1- Excluding capitalized overhead; First year of analysis includes all prior year spending																					

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Gross Plant in Service & Contributions in Aid of Construction
Appendix D - Schedule 7
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Gross Plant in Service**																					
2																						
3	Gross Plant in Service, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
5	Foundation	Preceeding Year, Line 32	-	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
6	NG Dehydrator	Preceeding Year, Line 33	-	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 9	-	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
11																						
12	Gross Plant in Service, Additions																					
13	CNG Dispensing Equipment	Schedule 6, Lines 2 + 8 + 14 + 20	1,400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Foundation	Schedule 6, Lines 3 + 9 + 15 + 21	442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	NG Dehydrator	Schedule 6, Lines 4 + 10 + 16 + 22	44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																						
17																						
18	Capitalized Overhead	Schedule 2, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Gross Plant in Service, Additions	Sum of Lines 13 through 18	1,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																						
21	Gross Plant in Service, Retirements																					
22	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Gross Plant in Service, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Gross Plant in Service, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
32	Foundation	Line 5 + Line 14 + Line 23	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
33	NG Dehydrator	Line 6 + Line 15 + Line 24	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Gross Plant in Service, Ending	Sum of Lines 31 through 36	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
38																						
39																						
40	**Contributions in Aid of Construction (CIAC)**																					
41	CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Accumulated Depreciation & Amortization
Appendix D - Schedule 8
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Accumulated Depreciation**																					
2																						
3	Accumulated Depreciation, Beginning																					
4	CNG Dispensing Equipment	Preceeding Year, Line 31	-	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)
5	Foundation	Preceeding Year, Line 32	-	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)
6	NG Dehydrator	Preceeding Year, Line 33	-	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)
7																						
8																						
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 9	-	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)
11																						
12	Accumulated Depreciation, Depreciation Expense[1]																					
13	CNG Dispensing Equipment@ 5%	Schedule 7, Line 4 & Line 13	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
14	Foundation@ 5%	Schedule 7, Line 5 & Line 14	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
15	NG Dehydrator@ 5%	Schedule 7, Line 6 & Line 15	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
16																						
17																						
18	Capitalized Overhead@ 0%	Schedule 7, Line 9 & Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Accumulated Depreciation, Depreciation Exp	Sum of Lines 13 through 18	(95)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)	(94)
20																						
21	Accumulated Depreciation, Retirements																					
22	CNG Dispensing Equipment	Schedule 7, Line 22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Foundation	Schedule 7, Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	NG Dehydrator	Schedule 7, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																						
26																						
27	Capitalized Overhead	Schedule 7, Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Accumulated Depreciation, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																						
30	Accumulated Depreciation, Ending																					
31	CNG Dispensing Equipment	Line 4 + Line 13 + Line 22	(70)	(140)	(210)	(280)	(350)	(420)	(490)	(560)	(630)	(700)	(770)	(840)	(910)	(980)	(1,050)	(1,120)	(1,190)	(1,260)	(1,330)	(1,400)
32	Foundation	Line 5 + Line 14 + Line 23	(22)	(44)	(66)	(88)	(111)	(133)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(332)	(354)	(376)	(398)	(420)	(442)
33	NG Dehydrator	Line 6 + Line 15 + Line 24	(2)	(4)	(7)	(9)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(28)	(31)	(33)	(35)	(37)	(39)	(42)	(44)
34																						
35																						
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Accumulated Depreciation, Ending	Sum of Lines 31 through 36	(95)	(189)	(283)	(377)	(472)	(566)	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
38																						
39																						
40	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**																					
41	Accumulated Amortization CIAC, Beginning	Preceeding Year, Line 44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Amortization	[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Accumulated Amortization CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45																						
46	**Removal Cost Provision**																					
47	CNG Dispensing Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Foundation	-Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
49	NG Dehydrator		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Total Removal Cost Provision	Sum of Lines 47 through 49	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
51																						
52	**Negative Salvage Continuity - Foundation**																					
53	Opening Balance	Preceeding Year, Line 56	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)
54	Provision (Cr.)[2]	Annual Salvage Rate x Schedule 7, (Line 5 + Line 32) /2	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
55	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
56	Ending Balance	Sum of Lines 53 through 55	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
57																						
58	1- Depreciation & Amortization Expense calculation is based on opening balance + (additions x in-service days/365 if it is the in-service year for project/; otherwise, additions x 1/2)																					
59	2- Annual Salvage Rate calculation is 0.11% based on (foundation costs / removal costs / retirement years																					

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Deferred Charges & Deficiency / Surplus [Tracker]
Appendix D - Schedule 9
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Deficiency / Surplus [Tracker]**																					
2	Opening Balance	Previous Year, Line 10	-	39	31	29	28	24	15	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Gross Addition	Schedule 11, Line 21	39	(11)	(4)	(4)	(6)	(10)	(17)	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Addition	Line 3 + Line 4	39	(11)	(4)	(4)	(6)	(10)	(17)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	AFUDC																					
7	Equity	(Line 2) x (Schedule 10, Lines 8 x 9)	-	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Debt	[1]	-	1	1	1	1	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Interest Adjustment	[2]	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Closing Balance	Sum of Lines 5 through 9	39	31	29	28	24	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11																						
12	**BFI Application Costs**																					
13	Opening Balance	Previous Year, Line 20	-	32	27	21	16	11	5	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Opening Balance, Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Gross Additions		50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax		(13)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Net Additions		38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Amortization Expense		(5)	(5)	(5)	(5)	(5)	(5)	(5)	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Closing Balance	Line 13 + Line 17 + Line 18	32	27	21	16	11	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																						
21	Deferred Charge, Mid-Year	(Line 13+ Line 14 + Line 19) / 2	16	29	24	19	13	8	3	-	-	-	-	-	-	-	-	-	-	-	-	-
22																						
23	1- (Line 2) x [Schedule 10 , (Lines 11 x 12+ Lines 13 x 14) x (1- Tax Rate)]																					
24	2- Adjustment to net account to zero in final year; result of varying WACC rates throughout contract																					

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Present Value of Revenue Requirement
Appendix D - Schedule 10
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1																						
2	Annual Revenue Requirement (Excluding O&M)	Schedule 1, Line 12 -Line 3	262.0	216.5	227.4	232.7	235.2	235.6	234.2	228.1	224.6	220.0	214.9	209.1	202.9	196.3	189.4	182.2	174.9	167.4	159.8	149.2
3	Annual Number of Customers		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	Annual Revenue Requirement (O&M)	Schedule 1, Line 3	50.0	51.0	52.1	53.1	54.2	55.3	56.4	57.6	58.7	59.9	61.1	62.4	63.6	64.9	66.2	67.6	69.0	70.4	71.8	73.2
5																						
6	**Annual Discount Rate**																					
7	Equity Component																					
8	ROE %		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
9	Equity Portion		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
10	Debt Component																					
11	Long Term Debt Rate		6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%
12	Long Term Debt Portion		58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%
13	Short Term Debt Rate		4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
14	Short Term Debt Portion		1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%
15																						
16	Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Pre- Tax Weighted Average Cost of Capital (WACC)[1]		9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
18	After- Tax Weighted Average Cost of Capital (WACC)[2]		6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
19																						
20	**Present Value of Revenue Requirement**																					
21	PV of Annual Cost of Service (excl O&M) Revenue Requirement	Line 2 / (1 + Line 18)^Yr	245.1	189.4	186.2	178.2	168.6	157.9	146.9	133.8	123.3	112.9	103.2	93.9	85.3	77.2	69.7	62.7	56.3	50.4	45.0	39.3
22	PV of Annual Revenue Requirement ($/Mnth)		20	16	16	15	14	13	12	11	10	9	9	8	7	6	6	5	5	4	4	3
23	Total PV of Cost of Service (excl O&M)	Sum of Line 21	2,325.2																			
24	Total PV of Cost of Service (excl O&M) over contract term		1,272.3																			
25	PV of Annual O&M	Line 4 / (1 + Line 18)^Yr	46.8	44.6	42.6	40.7	38.8	37.1	35.4	33.8	32.2	30.8	29.4	28.0	26.7	25.5	24.4	23.3	22.2	21.2	20.2	19.3
26	Total PV of O&M	Sum of Line 25	622.9																			
27	Total PV of O&M over contract term		286.0																			
28																						
29	PV of Annual Customers	Line 3 / (1 + Line 18)^Yr	0.9	0.9	0.8	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
30	Total PV of Customers	Sum of Line 29	10.6																			
31																						
32																						
33	**Tariff Analysis**																					
34	Annual Volume (TJ)		60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
35																						
36	**Cost of Service (excluding O&M)**																					
37	Annual Cost of Service per Customer ($/Yr)	Line 2 x 1000 / Line 3	262,036	216,458	227,376	232,683	235,246	235,612	234,217	228,087	224,645	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
38	Monthly Cost of Service per Customer ($/Mnth)	Line 37 / 12	21,836	18,038	18,948	19,390	19,604	19,634	19,518	19,007	18,720	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
39	Annual Volumetric Cost of Service ($/GJ)	Line 2 / Line 34	4.367	3.608	3.790	3.878	3.921	3.927	3.904	3.801	3.744	3.667	3.581	3.485	3.382	3.272	3.156	3.037	2.915	2.790	2.663	2.486
40																						
41	**O&M**																					
42	Annual Cost of Service per Customer ($/Yr)	Line 4 x 1000 / Line 3	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
43	Monthly Cost of Service per Customer ($/Mnth)	Line 42 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
44	Annual Volumetric Cost of Service ($/GJ)	Line 4 / Line 34	0.833	0.850	0.868	0.885	0.903	0.921	0.940	0.959	0.979	0.999	1.019	1.040	1.061	1.082	1.104	1.127	1.149	1.173	1.197	1.221
45																						
46	**Levelized Tariff Analysis**																					
47	PV of Annual Volume (TJ)	Line 34 / (1 + Line 18)^Yr	56.1	52.5	49.1	46.0	43.0	40.2	37.6	35.2	32.9	30.8	28.8	27.0	25.2	23.6	22.1	20.6	19.3	18.1	16.9	15.8
48	Total PV of Volume (TJ)	Sum of Line 47	640.8																			
49																						
50	Levelized Annual Delivery Charge per Customer ($/Yr)	Line 23 x 1000 / Line 30	**276,943**																			
51	Levelized Monthly Delivery Charge per Customer ($/Mnth)	Line 50 / 12	**23,079**																			
52	Levelized Volumetric Delivery Rate ($/GJ)	(Line 23 + Line 26) / Line 48	**4.600**																			
53																						
54	1- (Line 8 x Line 9) / 1- Line 16 + (Line 11 x Line 12 + Line 13 x Line 14)																					
55	2- Line 9 x Line 10 + [(Line 12 x Line 13 + Line 14 x Line 15) x 1- Line 17]																					

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Contract Rate Design
Appendix D - Schedule 11
($), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cost of Service (Excluding O&M)**																					
2	Required Delivery Revenue ($) (discounted) - 20 years	Schedule 10, Line 23 x 1000	2,325,246																			
3	Required Delivery Revenue ($) (discounted, contract term) - 7 yrs	Schedule 10, Line 24 x 1000	1,272,260																			
4	Flat Rate for 20 Years		276,943																			
5																						
6	Year 1 Contract Rate, Escalated at 2% Annually	[1]	222,641																			
7	Annual Contract Rate Escalation		2.00%																			
8																						
9	Annual Discount Rate (After- Tax WACC)	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
10	Annual Contract Rate	[2]	222,641	227,094	231,636	236,269	240,994	245,814	250,730	228,087	224,645	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
11	PV of Annual Contract Rate	Line 10 / (1 + Line 9)^Yr	208,280	198,741	189,640	180,955	172,668	164,761	157,215	133,792	123,273	112,948	103,186	93,946	85,272	77,176	69,658	62,706	56,298	50,408	45,010	39,315
12	Cumulative Revenue		449,736	227,094	681,372	917,640	1,158,635	1,404,449	1,655,179	1,883,266	2,107,911	2,327,933	2,542,798	2,751,914	2,954,808	3,151,102	3,340,491	3,522,734	3,697,634	3,865,036	4,024,817	4,174,004
13	PV of Cumulative Revenue		407,021	198,741	388,381	569,336	742,005	906,765	1,063,981	1,197,772	1,321,045	1,433,993	1,537,178	1,631,125	1,716,396	1,793,572	1,863,231	1,925,937	1,982,234	2,032,643	2,077,652	2,116,967
14	PV of Revenue Collected	Sum of Line 11	2,325,246																			
15																						
16																						
17	Monthly Rate, Escalated at 2% annually and then COS based beyond Contract Term		18,553	18,925	19,303	19,689	20,083	20,485	20,894	19,007	18,720	18,335	17,905	17,426	16,908	16,358	15,782	15,187	14,575	13,950	13,315	12,432
18	Annual Volumetric Contract Rate ($/GJ)	Line 10 / Line 30 / 1000	**3.711**	**3.785**	**3.861**	**3.938**	**4.017**	**4.097**	**4.179**	**3.801**	**3.744**	**3.667**	**3.581**	**3.485**	**3.382**	**3.272**	**3.156**	**3.037**	**2.915**	**2.790**	**2.663**	**2.486**
19																						
20	Annual Cost of Service (excl O&M)	Schedule 10, Line 2 x 1000	262,036	216,458	227,376	232,683	235,246	235,612	234,217	228,087	224,645	220,022	214,865	209,116	202,894	196,294	189,390	182,242	174,900	167,403	159,781	149,187
21	Annual Difference (Cost of Service - Contract Rate)	Line 20 - Line 10	39,395	(10,636)	(4,260)	(3,585)	(5,748)	(10,202)	(16,514)	-	-	-	-	-	-	-	-	-	-	-	-	-
22																						
23	**Cost of Service (O&M)**																					
24	Forecast Annual BC CPI Rate	CPI BC Stats Canada	1.99%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%
25	Annual O&M Expense	Schedule 1, Line 3 x 1000	50,000	51,015	52,051	53,107	54,185	55,285	56,408	57,553	58,721	59,913	61,129	62,370	63,636	64,928	66,246	67,591	68,963	70,363	71,791	73,249
26																						
27	Monthly Rate, Escalated at CPI annually	Line 25 / 12	4,167	4,251	4,338	4,426	4,515	4,607	4,701	4,796	4,893	4,993	5,094	5,198	5,303	5,411	5,521	5,633	5,747	5,864	5,983	6,104
28	Annual O&M Volumetric Contract Rate ($/GJ)	Line 25 / Line 30 / 1000	**0.833**	**0.850**	**0.868**	**0.885**	**0.903**	**0.921**	**0.940**	**0.959**	**0.979**	**0.999**	**1.019**	**1.040**	**1.061**	**1.082**	**1.104**	**1.127**	**1.149**	**1.173**	**1.197**	**1.221**
29																						
30	Annual Volume (TJ)	Minimum contract demand	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
31																						
32	Cost of Service (excl O&M) Volumetric Contract Rate ($/GJ)	Line 18	3.711	3.785	3.861	3.938	4.017	4.097	4.179	3.801	3.744	3.667	3.581	3.485	3.382	3.272	3.156	3.037	2.915	2.790	2.663	2.486
33	O&M Volumetric Contract Rate ($/GJ)	Line 28	0.833	0.850	0.868	0.885	0.903	0.921	0.940	0.959	0.979	0.999	1.019	1.040	1.061	1.082	1.104	1.127	1.149	1.173	1.197	1.221
34	Annual Overhead Allocation Charge ($/GJ)	[3]	0.200	0.204	0.208	0.212	0.217	0.221	0.226	0.230	0.235	0.240	0.245	0.249	0.255	0.260	0.265	0.270	0.276	0.281	0.287	0.293
35	**Total Annual Volumetric Contract Rate ($/GJ]**	Sum of Line 32 to Line 34	**4.744**	**4.839**	**4.936**	**5.035**	**5.136**	**5.239**	**5.345**	**4.991**	**4.958**	**4.905**	**4.844**	**4.774**	**4.697**	**4.613**	**4.526**	**4.434**	**4.340**	**4.244**	**4.147**	**4.000**
36	**Annual Forecast Revenue**	(Line 30 x Line 35) x 1000	**284,641**	**290,353**	**296,179**	**302,122**	**308,184**	**314,368**	**320,676**	**299,452**	**297,459**	**294,314**	**290,666**	**286,455**	**281,803**	**276,805**	**271,535**	**266,055**	**260,414**	**254,653**	**248,802**	**240,015**
37																						
38	**Contract Termination**[4]																					
39																						
40	Deferral Account Repayment	Schedule 9, Line 10	39,395	31,475	29,384	27,825	23,996	15,448	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Residual Asset Value	[5]	1,790,238	1,695,475	1,600,712	1,505,949	1,411,186	1,316,423	1,221,660	1,126,897	1,032,134	937,371	842,608	747,845	653,082	558,320	463,557	368,794	274,031	179,268	84,505	9,742
42	Approximate Contract Termination Fee ($)	Line 40 + Line 41	1,829,633	1,726,950	1,630,097	1,533,774	1,435,182	1,331,872	1,221,660	1,126,897	1,032,134	937,371	842,608	747,845	653,082	558,320	463,557	368,794	274,031	179,268	84,505	9,742
43																						

44 1- Line 3 /sum of [(1+2%) ^ year / (1+WACC) ^ year] for each year of the contract
45 2- Previous Year x (1+ 2%); in 2019+, Line 20
46 3- Previous Year x (1+ BC CPI)
47 4- The forecast early termination fee has been calculated on a year end basis. The actual fee would be determined at the time of contract termination and may be different than the amount shown on Line 42. Reference to Section 12B.5, Clause 11.1 of Appendix B in BFI Application
48 5- Schedule 5, (Line 3 + Line 6+ Line 9+ Line 12+ Line 15 + Schedule 8 Line 55) x 1000

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Discounted Cash Flow Analysis
Appendix D - Schedule 12
($000's), unless otherwise stated

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Cash Flow**																					
2	Add: Revenue	Schedule 11, Line 36	285	290	296	302	308	314	321	299	297	294	291	286	282	277	272	266	260	255	249	240
3	Less: O&M, Property Tax Expense	Schedule 1, - (Line 3 + Line 4)	(67)	(69)	(72)	(74)	(75)	(77)	(78)	(80)	(82)	(83)	(85)	(86)	(88)	(89)	(91)	(93)	(95)	(97)	(98)	(100)
4	EBITDA[1]	Line 2 + Line 3	217	222	224	228	233	238	242	220	216	211	206	200	194	187	180	173	166	158	150	140
5	Capital Expenditures[2]	Schedule 6, Line 25 + Line 29	(1,861)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
6	Pre-Tax Cash Flow	Line 4 + Line 5	(1,643)	222	224	228	233	238	242	220	216	211	206	200	194	187	180	173	166	158	150	130
7	Income Tax Expense	Line 4 x (- Schedule 3, Line 13)	(54)	(55)	(56)	(57)	(58)	(59)	(61)	(55)	(54)	(53)	(52)	(50)	(49)	(47)	(45)	(43)	(41)	(40)	(38)	(35)
8	Overhead Capitalized Tax Shield	Schedule 3, -Line 8 x Line 13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	CCA Tax Shield/Removal Cost	Schedule 3, (-Line 9 + Line 10) x Schedule 3, Line 13	39	70	57	47	38	31	26	21	18	15	12	10	9	7	6	6	5	4	4	6
10	Terminal Value of CCA Tax Shield	[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
11	Terminal Value	[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																						
13	Free Cash Flow	Line 6 + Line 7	(1,659)	237	225	218	213	209	207	186	180	173	167	161	154	148	142	135	129	123	117	119
14																						
15	After Tax WACC %	Schedule 10, Line 18	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
16	Present Value of Free Cash Flow[3]	Line 13 / (1 + Line 15)^Yr	(1,672)	207	184	167	152	140	130	109	99	89	80	72	65	58	52	47	42	37	33	31
17	Total Present Value of Free Cash Flow	Sum of Line 16	122																			
18																						

19 1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)
20 2- Net of CIAC and removal costs (if applicable) and excludes capitalized overhead
21 3- 2012 present value calculates capital expenditure to occur at time zero
22 4- [Class 8 UCC Closing Balance x CCA Rate / (CCA Rate + WACC) + Class 1.3 UCC Closing Balance x CCA Rate / (CCA Rate + WACC)] x Income Tax Rate
23 5- Evaluation period reflects the useful life of the assets, therefore it is assumed that the terminal value is zero

FortisBC Energy Inc.
CNG BFI Cost of Service

CNG BFI Cost of Service: Approximate Contract Termination Fee
Appendix B - Section 12B.5, Clause 11.1
($000's), unless otherwise stated

Line	Particulars	Reference	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Total Gross Plant in Service, Ending	Schedule 7, Line 37	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,885
2	Accumulated Depreciation, Ending	Schedule 8, Line 37	(660)	(754)	(849)	(943)	(1,037)	(1,131)	(1,226)	(1,320)	(1,414)	(1,508)	(1,603)	(1,697)	(1,791)	(1,886)
3	Net Salvage, Ending	Schedule 8, Line 56	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(9)	(9)	(10)	-
4	Add: Removal Costs[1]															
5	Less: Excess Fueling Station Recoveries[2]															
6	**Net Termination Payment**	Sum of Line 1 to Line 5	**1,222**	**1,127**	**1,032**	**937**	**843**	**748**	**653**	**558**	**464**	**369**	**274**	**179**	**85**	**(0)**
7																
8																

9 1- Actual removal costs to be determined at time of contract termination and will be less the net salvage collected to date
10 2- Cumulative fueling station recoveries received from volumes in excess of minimum contract demand