Appendix A

ENERGY PLANNING ENVIRONMENT

2010 Legislative Session: 2nd Session, 39th Parliament
FIRST READING

HONOURABLE BLAIR LEKSTROM
MINISTER OF ENERGY, MINES AND
PETROLEUM RESOURCES

BILL 17 — 2010
CLEAN ENERGY ACT

Contents

Explanatory Note

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

Definitions

1 (1) In this Act:

"acquire", used in relation to the authority, means to enter into an energy supply contract;

"authority" has the same meaning as in section 1 of the *Hydro and Power Authority Act*;

"British Columbia's energy objectives" means the objectives set out in section 2;

"Burrard Thermal" means the gas-fired generation asset owned by the authority and located in Port Moody, British Columbia;

"clean or renewable resource" means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource;

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed;

"electricity self-sufficiency" means electricity self-sufficiency as described in section 6 (2);

"expenditure for export" means the amount of an expenditure for the construction or extension of a plant or system or for an acquisition of electricity that is in addition to the amount the authority would have had to spend

(a) to achieve electricity self-sufficiency, and

(b) to undertake anything referred to in section 7 (1), except to the extent the expenditure is accounted for in paragraph (a);

"feed-in tariff program" means a program, that may be established under section 16, under which the authority offers to enter into energy supply contracts with persons generating electricity from clean or renewable resources using prescribed technologies in prescribed regions of British Columbia;

"greenhouse gas" has the same meaning as in section 1 of the *Greenhouse Gas Reduction Targets Act*;

"heritage assets" means

(a) any equipment or facilities for the transmission or distribution of electricity in respect of which, on the date on which this Act receives First Reading in the Legislative Assembly, a certificate of public convenience and necessity has been granted, or has been deemed to have been granted, to the authority or the transmission corporation under the *Utilities Commission Act*,

(b) generation and storage assets identified in Schedule 1 of this Act, and

(c) equipment and facilities that are for the transmission or distribution of electricity and that are identified in Schedule 1 of this Act;

"integrated resource plan" means an integrated resource plan required to be submitted under section 3;

"transmission corporation" means British Columbia Transmission Corporation.

(2) Words and expressions used but not defined in this Act or the regulations, unless the

context otherwise requires, have the same meanings as in the *Utilities Commission Act*.

PART 1 — BRITISH COLUMBIA'S ENERGY OBJECTIVES

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

Integrated resource plans

3 (1) The authority must submit to the minister, in accordance with subsection (6), an integrated resource plan that is consistent with good utility practice and that includes all of the following:

(a) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency;

(b) a description of what the authority plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives, including plans respecting

(i) the implementation of demand-side measures,

(ii) the construction or extension of facilities,

(iii) the acquisition of electricity from other persons, and

(iv) the use of rates, including rates to encourage

(A) energy conservation or efficiency,

(B) the use of energy during periods of lower demand,

(C) the reduction of the energy demand the authority must serve, or

(D) the development and use of electricity from clean or renewable resources;

(c) a description of the consultations carried out by the authority respecting the development of the integrated resource plan;

(d) a description of

(i) the expected export demand during a defined period,

(ii) the potential for British Columbia to meet that demand,

(iii) the actions the authority has taken to seek suitable opportunities for the export of electricity from clean or renewable resources, and

(iv) the extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports;

(e) if the authority plans to make an expenditure for export, a specification of the amount of the expenditure and a rationale for making it.

(2) In the first integrated resource plan the authority submits to the minister, and in any other integrated resource plan the minister by order specifies, the authority must include a description of the authority's infrastructure and capacity needs for electricity transmission for the period ending 30 years after the date the integrated resource plan is submitted.

(3) The description referred to in subsection (2) must include an assessment of the potential for developing, during the period referred to in subsection (2), grouped by geographic area, electricity generation from clean or renewable resources in British Columbia.

(4) The authority must carry out any consultations required by a regulation under section 35 (g) and submit a report to the minister, within the time prescribed, respecting those consultations.

(5) The authority must plan to rely on no energy and no capacity from Burrard Thermal, except in the case of emergency or as authorized by regulation.

(6) An integrated resource plan must be submitted

(a) within 18 months from the date this Part comes into force, and

(b) once every 5 years after the submission under paragraph (a), unless a submission date is prescribed for the purposes of this subsection, in which case an integrated resource plan must be submitted by the prescribed submission date.

(7) The authority may submit an amendment to an integrated resource plan approved under section 4, and section 4 applies to the submission.

(8) If the Lieutenant Governor in Council approves an amendment submitted under subsection (7), the approved amendment is to be considered a part of the approved integrated resource plan.

Approval and procurement

4 (1) After the minister receives an integrated resource plan, the Lieutenant Governor in Council, for the purposes of sections 44.2 (5.1), 46 (3.3) and 71 (2.21) and (2.51) of the *Utilities Commission Act*, may, by order,

(a) approve or reject the plan, and

(b) if the Lieutenant Governor in Council is satisfied that it is in the interests of British Columbians to pursue opportunities for export, require the authority, its subsidiaries or both to do the following:

(i) begin a process or processes by the time specified in the order to acquire the specified amount per year of energy and capacity from clean or renewable resources;

(ii) acquire the energy and capacity referred to in subparagraph (i) within the time specified in the order;

(iii) secure the necessary transmission capacity;

(iv) submit, for the purposes of subsection (2), a report to the minister respecting the expenditures for export resulting from compliance with subparagraphs (i) to (iii).

(2) In an order under subsection (1) (b) of this section, the Lieutenant Governor in Council may exempt the authority from sections 45 to 47 of the *Utilities Commission Act* with respect to anything to be done under subsection (1) (b) (iii) of this section.

(3) The authority and its subsidiaries and persons and their successors and assigns who enter into an energy supply contract as a result of a process referred to in subsection (1) (b) (i) of this section are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(4) The Lieutenant Governor in Council, for the purposes of subsection (5) (a), may approve a report submitted under subsection (1) (b) (iv).

(5) In setting rates for the authority, the commission must ensure that the rates do not allow the authority to recover

(a) its expenditures for export as set out in a report approved by the Lieutenant Governor in Council under subsection (4), and

(b) any other expenditures for export.

Status report

5 (1) The authority must submit to the minister, by the time the minister requires, a status report respecting the authority's most recently approved integrated resource plan.

(2) The minister must make public a status report submitted under subsection (1) in the same manner and at the same time that the minister makes public a service plan under the *Budget Transparency and Accountability Act*.

Electricity self-sufficiency

6 (1) In this section:

"electricity supply obligations" means

(a) electricity supply obligations for which rates are filed with the commission under section 61 of the *Utilities Commission Act*, and

(b) any other electricity supply obligations that exist at the time this section comes into force,

determined by using the authority's prescribed forecasts of its energy requirements and peak load, taking into account demand-side measures, that are in an integrated resource plan approved under section 4;

"heritage energy capability" means the maximum amount of annual energy that the heritage assets that are hydroelectric facilities can produce under prescribed water conditions.

(2) The authority must achieve electricity self-sufficiency by holding,

(a) by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations, and

(b) by the year 2020 and each year after that, the rights to 3 000 gigawatt hours of energy, in addition to the amount of electricity referred to in paragraph (a), and the capacity required to integrate that energy

solely from electricity generating facilities within the Province,

(c) assuming no more in each year than the heritage energy capability, and

(d) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

(3) The authority must remain capable of meeting its electricity supply obligations from the electricity referred to in subsection (2) (a) and (b), except to the extent the authority may be permitted, by regulation, to enter into contracts in the prescribed circumstances and on the prescribed terms and conditions.

(4) A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider British Columbia's energy objective to achieve electricity self-sufficiency.

Exempt projects, programs, contracts and expenditures

7 (1) The authority is exempt from sections 45 to 47 and 71 of the *Utilities Commission Act* to the extent applicable, and from any other sections of that Act that the minister may specify by regulation, with respect to the following projects, programs, contracts and expenditures of the authority, as they may be further described by regulation:

(a) the Northwest Transmission Line, a 287 kilovolt transmission line between the Skeena substation and Bob Quinn Lake, and related facilities and contracts;

(b) Mica Units 5 and 6, a project to install two additional turbines and related works and equipment at Mica;

(c) Revelstoke Unit 6, a project to install an additional turbine and related works and equipment at Revelstoke;

(d) Site C, a project to build a third dam on the Peace River in northeast British Columbia to provide approximately

(i) 4 600 gigawatt hours of energy each year, and

(ii) 900 megawatts of capacity;

(e) a bio-energy phase 2 call to acquire up to 1 000 gigawatt hours per year of electricity;

(f) one or more agreements with pulp and paper customers eligible for funding under Canada's Green Transformation Program under which agreement or agreements the authority acquires, in aggregate, up to 1 200 gigawatt hours per year of electricity;

(g) the clean power call request for proposals, issued on June 11, 2008, to acquire up to 5 000 gigawatt hours per year of electricity from clean or renewable resources;

(h) the standing offer program described in section 15;

(i) the feed-in tariff program described in section 16;

(j) the actions taken to comply with section 17 (2) and (3);

(k) the program described in section 17 (4).

(2) The persons and their successors and assigns who enter into an energy supply contract with the authority related to anything referred to in subsection (1) are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent the authority from doing anything referred to in subsection (1).

Rates

8 (1) In setting rates under the *Utilities Commission Act* for the authority, the commission must ensure that the rates allow the authority to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to

(a) the achievement of electricity self-sufficiency, and

(b) a project, program, contract or expenditure referred to in section 7 (1), except

(i) to the extent the expenditure is accounted for in paragraph (a), and

(ii) for costs, prescribed for the purposes of this section, respecting the feed-in tariff program.

(2) Subject to subsection (1) of this section, the commission must set under the *Utilities Commission Act* a rate proposed by the authority with respect to the project referred to in section 7 (1) (a) of this Act.

(3) The commission must not, except on application by the authority, cancel, suspend or amend a rate set in accordance with subsection (2).

(4) The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates.

Domestic long-term sales contracts

9 The authority must establish, in accordance with the regulations, a program to develop potential offers respecting domestic long-term sales contracts for availability to prescribed classes of customers on prescribed terms, including terms respecting price, for prescribed volumes of energy over prescribed periods.

Part 2 — Prohibitions

Two-rivers system development

10 In this Part:

"approval" includes a certificate, licence, permit or other authorization;

"prohibited projects" means

(a) a project of the authority, referred to in Schedule 2 of this Act, for electricity generation on a stream, and

(b) a project for electricity generation on a stream with a storage capability in excess of a prescribed storage capability,

but does not include the two-rivers projects;

"stream" has the same meaning as in section 1 of the *Water Act*;

"two-rivers projects" means

(a) the authority's facilities, on the Peace River and the Columbia River System, existing on the date this section comes into force and upgrades or extensions to those facilities, and

(b) the project commonly known as Site C.

Project prohibitions

11 (1) Despite any other enactment, a minister, or an employee or agent of the government or of a municipality or regional district, must not issue an approval under an applicable enactment for a person to

(a) undertake a prohibited project, or

(b) construct all or part of the facilities of a prohibited project.

(2) Despite any other enactment, an approval under another enactment is without effect if it is issued contrary to subsection (1).

Prohibited acquisitions

12 (1) In this section:

"facility" means a facility for the generation of electricity and any transmission or distribution equipment to deliver that electricity to the point of interconnection with the authority's integrated service area;

"protected area" means

(a) a park, recreation area, or conservancy, as defined in section (1) of the *Park Act*,

(b) an area established under the *Environment and Land Use Act* as a park or protected area, or

(c) an area established or continued as an ecological reserve under the *Ecological Reserve Act* or by the *Protected Areas of British Columbia Act*.

(2) The authority must not make an offer to acquire electricity from a person whose proposed facility is to be located, in whole or in part, in a protected area, unless the location is permitted under the enactments referred to in the definition of "protected area" in subsection (1).

(3) A person referred to in subsection (2) must not offer to sell electricity to the authority.

Burrard Thermal

13 The authority must not operate Burrard Thermal, except

(a) in the case of emergency,

(b) to provide transmission support services, or

(c) as authorized by regulation.

Part 3 — Preserving Heritage Assets

Sale of heritage assets prohibited

14 (1) The authority must not sell or otherwise dispose of the heritage assets.

(2) Nothing in subsection (1) prevents the authority from disposing of heritage assets if the assets disposed of are no longer used or useful for their intended purpose, or they are to be replaced with one or more assets that will perform similar functions.

Part 4 — Standing Offer and Feed-in Tariff Programs

Standing offer program

15 (1) In this section:

"eligible facility" means a generation facility that

(a) either

(i) has only one generator and the generator's nameplate capacity is less than or equal to the maximum nameplate capacity or has more than one generator and the total nameplate capacity of all of them is a capacity less than or equal to the maximum nameplate capacity, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources, but does not include a prescribed generation facility or class of generation facilities;

"maximum nameplate capacity" means 10 megawatts or, if another capacity is prescribed for the purposes of this section, the prescribed capacity.

(2) The authority must establish and, except in the prescribed circumstances, maintain a standing offer program to acquire electricity from eligible facilities.

(3) The authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the standing offer program under subsection (2) are to be made.

Feed-in tariff program

16 (1) To facilitate the achievement of one or more of British Columbia's energy objectives, the Lieutenant Governor in Council, by regulation, may require the authority to establish a feed-in tariff program.

(2) If the authority is required to establish a feed-in tariff program, the authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions under which offers may be made under the feed-in tariff program.

(3) The authority may not enter into an energy supply contract as a result of an offer made under the feed-in tariff program if the energy supply contract, by itself or in aggregate with other energy supply contracts entered into under the feed-in tariff program, would result in an expenditure that exceeds the prescribed amount in the prescribed period.

(4) Without limiting section 34 (2) (c),

(a) requirements prescribed by the Lieutenant Governor in Council, and

(b) criteria, terms and conditions established by the authority

made for the purpose of subsection (2) may be made with respect to different regions, prices and technologies.

Part 5 — Energy Efficiency Measures and Greenhouse Gas Reductions

Smart meters

17 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart grid" means the prescribed equipment;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters and related equipment in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) The authority must establish a program to install and put into operation a smart grid in accordance with and to the extent required by the regulations.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters, or of its smart grid.

(6) If a public utility, other than the authority, makes an application under the *Utilities Commission Act* in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

Greenhouse gas reduction

18 (1) In this section, **"prescribed undertaking"** means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia.

(2) In setting rates under the *Utilities Commission Act* for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking.

(4) A public utility referred to in subsection (2) must submit to the minister, on the minister's request, a report respecting the prescribed undertaking.

(5) A report to be submitted under subsection (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies.

Clean or renewable resources

19 (1) To facilitate the achievement of British Columbia's energy objective set out in section 2 (c), a person to whom this subsection applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) Subsection (1) applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

Part 6 — First Nations Clean Energy Business Fund

First Nations Clean Energy Business Fund

20 (1) In this section:

"first nation" means

(a) a band, as defined in the *Indian Act* (Canada), and

(b) an aboriginal governing body, however organized and established by aboriginal people;

"power project" means an electricity generation or transmission project

(a) that is in a class of projects prescribed for the purposes of this section, other than a project of any organization in the government reporting entity, as defined in the *Budget Transparency and Accountability Act*,

(b) for which a licence, if applicable, under the *Water Act* for a power purpose, as defined section 1 of that Act, is issued after the date this section comes into force, and

(c) for which a prescribed authorization, if applicable, under an enactment respecting land is granted after this section comes into force;

"special account" means the special account, as defined in section 1 of the *Financial Administration Act*, established under subsection (2) of this section.

(2) A special account, to be known as the First Nations Clean Energy Business Fund special account, is established.

(3) The initial balance of the special account is an amount, not to exceed $5 million, prescribed by Treasury Board.

(4) The balance of the special account is increased by

(a) any other amount received by the government for payment into the account, and

(b) a prescribed percentage of the prescribed land and water revenues the government derives from power projects.

(5) Despite section 21 (3) of the *Financial Administration Act*, the minister, in accordance with a spending plan approved by Treasury Board, may pay an amount of money out of the special account for any of the following purposes:

(a) to share the revenues referred to in subsection (4) (b), up to a prescribed percentage of the revenue, under an agreement or agreements with one or more first nations;

(b) to facilitate the participation of first nations and aboriginal people in the clean energy sector;

(c) to pay the costs of administering the special account.

Part 7 — Transmission Corporation

Division 1 — Transfer of Property, Shares and Obligations

Definitions

21 In this Division:

"excluded contract" means a contract that was entered into, assumed by or assigned to the transmission corporation and that is governed by the law of a jurisdiction other than British Columbia;

"excluded permit" means a permit, approval, registration, authorization, licence, exemption, order or certificate issued, granted or provided to the transmission corporation under the law of a jurisdiction other than British Columbia;

"included contract" includes any contract entered into, assumed by or assigned to the transmission corporation, but does not include an excluded contract;

"included permit" includes a permit, approval, registration, authorization, licence, exemption, order or certificate, including a certificate of public convenience and necessity under the *Utilities Commission Act*, but does not include an excluded permit;

"right", in relation to a right held by the authority or the transmission corporation, includes a right under a trust, a cause of action and a claim.

Transfer of property

22 (1) Subject to subsection (2) and despite any enactment or law to the contrary, on the coming into force of this Part, all of the transmission corporation's rights, property, assets, included contracts and included permits are transferred to and vested in the authority.

(2) Subsection (1) does not apply to excluded contracts and excluded permits.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, the shares of the transmission corporation are transferred to and vested in the authority.

(4) The shares transferred to and vested in the authority under subsection (3) must not be sold or otherwise disposed of, but may be surrendered for cancellation.

(5) Despite any enactment or law to the contrary,

(a) the transfer and vesting effected by subsections (1) and (3) take effect without

(i) the execution or issue of any record, or

(ii) any registration or filing of this Act or any other record in or with any registry or other office,

(b) the transfer and vesting effected by subsections (1) and (3) take effect despite

(i) any prohibition on all or any part of the transfer and vesting, and

(ii) the absence of any consent or approval that is or may be required for all or any part of the transfer and vesting,

(c) if any right, property, asset, included contract or included permit referred to in subsection (1) is registered or otherwise recorded in the name of the transmission corporation, the registration or record may remain but is deemed, for all purposes of this and all other enactments and law, to reflect that the right, property, asset, included contract or included permit is owned by and vested in or held by the authority, and

(d) in any record in or by which the authority deals with a right, property, asset, included contract or included permit referred to in subsection (1), it is sufficient to cite this Act as effecting and confirming the transfer from the transmission corporation to the authority of the included contract or included permit or of the title to the right, property or asset and the vesting of that title in the authority.

(6) For the purposes of this section, assets that become assets of the authority under this section include records and parts of records, and, without limiting this, all of the records and parts of records of the transmission corporation are transferred to and become the records of the authority on the coming into force of this Part.

(7) Without limiting subsection (5) (c) of this section, or section 383.1 of the *Land Title Act*, if a right, property or asset referred to in subsection (1) of this section is registered or recorded in the name of the transmission corporation,

(a) the authority may, in its own name,

(i) effect a transfer, charge, encumbrance or other dealing with the right, property or asset, and

(ii) execute any record required to give effect to that transfer, charge, encumbrance or other dealing, and

(b) an official

(i) who has authority over a registry or office, including, without limitation, the personal property registry and a land title office, in which title to or interests in the right, property or asset is registered or recorded, and

(ii) to whom a record referred to in paragraph (a) (ii) executed by or on behalf of the authority is submitted in support of the transfer, charge, encumbrance or other dealing

must give the record the same effect as if it had been duly executed by the transmission corporation.

Transfer of obligations and liabilities

23 On the coming into force of this Part, all obligations and liabilities of the transmission corporation, except for obligations and liabilities under an excluded contract or excluded permit,

(a) are transferred to and assumed by the authority,

(b) become the authority's obligations and liabilities,

(c) cease to be obligations and liabilities of the transmission corporation, and

(d) may be enforced against the authority as if the authority had incurred them.

Records of transferred assets and liabilities

24 (1) Subject to subsection (2), a reference to the transmission corporation in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be a reference to the authority.

(2) If, under this Part, a part of a right, property, asset, obligation or liability is transferred to the authority, any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be amended to reflect the authority's interests in that right, property, asset, obligation or liability.

Transfer is not a default

25 Despite any provision to the contrary in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate, the transfer to the authority of a right, property, asset, included contract, included permit, share, obligation or liability under sections 22 and 23 does not constitute a breach or contravention of, or an event of default under, or confer a right to terminate the document, and, without limiting this, does not entitle any person who has an interest in the right, property, asset, included contract, included permit, share, obligation or liability to claim any damages, compensation or other remedy.

Legal proceedings

26 (1) Any legal proceeding being prosecuted or pending by or against the transmission corporation on the date this Part comes into force may be prosecuted, or its prosecution may be continued, by or against the authority, and may not be prosecuted or continued against the transmission corporation.

(2) A conviction against the transmission corporation may be enforced against the authority, and may not be enforced against the transmission corporation.

(3) A ruling, order or judgment in favour of or against the transmission corporation may be enforced by or against the authority, and may not be enforced by or against the transmission corporation.

(4) A cause of action or claim against the transmission corporation existing on the date this Part comes into force must be prosecuted against the authority.

(5) Subject to subsections (1) to (4), a cause of action, claim or liability to prosecution existing on the date this Part comes into force is unaffected by anything done under this Part.

Division 2 — Employees

Definitions

27 In this Division:

"adjustment plan" means an adjustment plan under section 54 of the *Labour Relations Code*;

"collective agreement" has the same meaning as in section 1 (1) of the *Labour Relations Code*.

Transfer of employees

28 (1) It is deemed that the persons who were, immediately before the coming into force of this Part, employees of the transmission corporation are, on the coming into force of this Part, transferred to and become employees of the authority.

(2) A question or difference between the authority and

(a) a transferred employee who is a member of a unit of employees for which a trade union has been certified under the *Labour Relations Code*, or

(b) a trade union representing transferred employees,

respecting the application of the *Labour Relations Code*, or the interpretation or application of this Division, may be referred to the Labour Relations Board in accordance with the procedure set out in the *Labour Relations Code* and its regulations.

(3) The Labour Relations Board may decide a question or difference referred to in subsection (2) in any of the ways, and by applying any of the remedies, available under the *Labour Relations Code*.

(4) On the date this Part comes into force, in respect of employees who are members of units of employees for which a trade union has been certified under the *Labour Relations Code*, the authority is the successor employer of those employees for the purposes of section 35 of the *Labour Relations Code*, without prejudice to the authority's right to apply for consolidation or merger of the bargaining units.

(5) If the authority or any trade union representing transferred employees makes an application to the Labour Relations Board to consolidate or merge the bargaining units representing transferred employees into a single bargaining unit for each trade union, the Labour Relations Board must consider that application having regard to the principles of business efficiency and without reference to the labour relations history at the authority or the transmission corporation relating to the presence of more than one bargaining unit for each trade union.

Continuous employment

29 (1) The transfer of a transferred employee does not constitute a termination of the transferred employee's employment for the purposes of

(a) an applicable collective agreement,

(b) any employment contract involving the transferred employee, and

(c) the *Employment Standards Act*.

(2) A transferred employee who is not subject to a collective agreement is deemed to have been employed by the authority without interruption in service.

(3) The service, with the transmission corporation, of a transferred employee who is not subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any employment contract.

(4) For the purposes of seniority, a transferred employee who is subject to a collective agreement is deemed to have been employed by the authority without interruption in service, unless the authority and the trade union representing the transferred employee have agreed to other seniority terms in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting seniority in the adjustment plan apply.

(5) The service, with the transmission corporation, of a transferred employee who is subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any collective agreement,

unless the authority and the trade union representing the transferred employee have agreed to other probationary periods, benefits and entitlements in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting probationary periods, benefits and entitlements in the adjustment plan apply.

(6) A transferred employee is deemed not to have been constructively dismissed solely by virtue of the transfer under section 28.

(7) Nothing in this Part

(a) prevents the employment of a transferred employee from being lawfully terminated after the transfer under section 28,

(b) prevents any term or condition of the employment of a transferred employee from being lawfully changed after the transfer under section 28, or

(c) removes any right or remedy of a person who is terminated after the transfer under section 28 or in respect of whom a term or condition of employment has been changed after the transfer under section 28.

Pensions

30 (1) For the purposes of the *Pension Benefits Standards Act*, the transfer of a transferred employee does not constitute a termination of membership in the transmission corporation's registered pension plan, or any other pension arrangement sponsored by the transmission corporation.

(2) Despite section 36 (1) of the *Hydro and Power Authority Act*, the authority does not require the approval of the Lieutenant Governor in Council to amend the authority's registered pension plan to implement the provisions of this Part, including the authority's assumption of all liability for the pension benefits payable under the transmission corporation's registered pension plan.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, all of the rights, property and assets that comprise

(a) the balance of fund account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the balance of fund account of the pension fund of the authority's registered pension plan, and

(b) the index reserve account and past service index reserve account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the index reserve account of the pension fund of the authority's registered pension plan,

and the resulting pension fund must be held by the trustee of the pension fund of the authority's registered pension plan.

(4) Section 22 (5) applies to the transfer and vesting effected by subsection (3) of this section.

Division 3 — General

Commission subject to direction

31 (1) The minister, by regulation, may issue a direction to the commission with respect to the exercise of powers and the performance of duties of the commission regarding any matter relating to a transfer made under this Part or to the service or rates referred to in section 32.

(2) The commission must comply with a direction issued under subsection (1) despite

(a) any provision of, or regulation under, the *Utilities Commission Act*, except any direction issued under section 3 of that Act, and

(b) any previous decision of the commission.

(3) This section is repealed on July 1, 2011.

Utilities Commission Act

32 (1) No approval, authorization, permit, certificate, exemption, permission, registration or order is required under the *Utilities Commission Act* with respect to

(a) the transmission corporation's ceasing to provide the service referred to in subsection (2) (a), or

(b) any transfer under this Part.

(2) The authority is deemed to have all the approvals, authorizations, permits, certificates, exemptions, permissions, registrations or orders that, under the *Utilities Commission Act*, are or may be required to continue

(a) to provide the service the transmission corporation provided immediately before the coming into force of this Part, and

(b) to charge, collect and enforce the rates the transmission corporation charged, collected and enforced immediately before the coming into force of this Part.

(3) The commission must not, except on application by the authority, cancel, suspend or amend

(a) any approval, authorization, permit, exemption, permission, registration, order or certificate, except for the certificate issued by commission Order C-4-08, that, under the *Utilities Commission Act*, the authority requires to provide the service and to charge, collect and enforce the rates referred to in subsection (2), or

(b) the service or rates referred to in subsection (2).

(4) Subsection (3) is repealed on July 1, 2011.

Designated agreements

33 On the coming into force of this Part, the agreements designated under section 3 of the *Transmission Corporation Act* have no force or effect.

Part 8 — Regulations

Division 1 — Regulations by Lieutenant Governor in Council

General

34 (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) In making a regulation under this Act, the Lieutenant Governor in Council may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

Regulations

35 Without limiting section 34 (1), the Lieutenant Governor in Council may make regulations as follows:

(a) respecting forecasts for the purposes of the definition of "electricity supply obligations" in section 6 (1);

(b) adding a heritage asset to Schedule 1 of this Act;

(c) prescribing water conditions for the purposes of the definition of "heritage energy capability" in section 6 (1);

(d) modifying or adding to British Columbia's energy objectives, except for the objective specified in section 2 (g);

(e) for the purposes of sections 44.1, 44.2, 46 and 71 of the *Utilities Commission Act*, respecting the application of British Columbia's energy objectives to public utilities other than the authority;

(f) establishing factors or guidelines the commission must follow in respect of British Columbia's energy objectives, including guidelines regarding the relative priority of the objectives set out in section 2;

(g) respecting consultations the authority must carry out in relation to

(i) the development of an integrated resource plan and of an amendment to an integrated resource plan,

(ii) an integrated resource plan submitted under section 3 (6), and

(iii) an amendment to an integrated resource plan submitted under section 3 (7);

(h) prescribing submission dates for the purposes of section 3 (6);

(i) respecting the authority's obligation under section 6 (3), including, without limitation, regulations permitting the authority to enter into contracts respecting the electricity referred to in section 6 (2) (a) and (b) and prescribing the terms and conditions on which, and the volume of electricity about which, the contracts may be entered into;

(j) respecting the program referred to in section 9, including prescribing classes of customers and terms;

(k) prescribing storage capability for the purposes of the definition of "prohibited projects" in section 10, including, without limitation, prescribing storage capability in terms of time, impoundment, mechanism or area;

(l) respecting the standing offer program to be established under section 15, including, without limitation, regulations that

(i) prescribe requirements, technologies, generation facilities and classes of generation facilities for the purposes of the definition of "eligible facility" in section 15 (1),

(ii) prescribe a capacity for the purposes of the definition of "maximum nameplate capacity" in section 15 (1),

(iii) prescribe circumstances for the purposes of section 15 (2), and

(iv) prescribe requirements for the purposes of section 15 (3);

(m) respecting the feed-in tariff program that may be established under section 16, including, without limitation, regulations that

(i) prescribe regions and technologies for the purposes of the definition of "feed-in tariff program" in section 1 (1),

(ii) require the authority to establish the feed-in tariff program,

(iii) prescribe requirements for the purposes of section 16 (2),

(iv) prescribe amounts and periods for the purposes of section 16 (3), and

(v) prescribe costs for the purposes of section 8 (1) (b);

(n) for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage

(i) the use of

(A) electricity, or

(B) energy directly from a clean or renewable resource

instead of the use of other energy sources that produce higher greenhouse gas emissions, or

(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging.

Division 2 — Regulations by Minister

General

36 (1) In making a regulation under this Act, the minister may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

(2) The minister may make a regulation defining, for the purposes of this Act, a word or expression used but not defined in this Act.

Regulations

37 The minister may make regulations as follows:

(a) prescribing resources for the purposes of the definition of "clean or renewable resource" in section 1 (1);

(b) prescribing exclusions for the purposes of the definition of "demand-side measure" in section 1 (1);

(c) authorizing the authority for the purposes of sections 3 (5), 6 and 13;

(d) describing the projects, programs, contracts and expenditures referred to in section 7 (1), including, without limitation, by specifying the property, interests, rights, activities, contracts and rates that comprise the projects, programs, contracts and expenditures;

(e) specifying sections of the *Utilities Commission Act* for the purposes of section 7 (1);

(f) respecting reports to be provided to the minister by the authority under section 8 (4), including, without limitation, regulations respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(g) for the purposes of section 17, respecting smart meters and smart-grids and their installation, including, without limitation,

(i) prescribing the types of smart meters to be installed, including the features or functions each meter must have or be able to perform,

(ii) prescribing types of smart grids to be installed, including, without limitation, equipment to detect unauthorized use or consumption of electricity, equipment to facilitate distributed generation and associated telecommunication and back-up systems, and

(iii) prescribing the classes of users for whom smart meters must be installed, and, without limiting section 36 (1) (c), requiring the authority to install different types of smart meters for different classes of users;

(h) prescribing targets, guidelines, public utilities and classes of public utilities for the purposes of section 19;

(i) issuing a direction for the purposes of section 31.

Division 3 — Regulations by Treasury Board

Regulations

38 Treasury Board may make regulations as follows:

(a) prescribing classes of projects and authorizations for the purposes of the definition of "power project" in section 20 (1), including, without limitation, prescribing classes of projects by reference to whether, or the extent to which, a project is a project of any organization of the government reporting entity, within the meaning of that definition;

(b) prescribing amounts and percentages for the purposes of section 20 (3), (4) (b) and (5) (a).

Part 9 — Transition

Transition

39 (1) The Lieutenant Governor in Council may make regulations considered appropriate for the purpose of more effectively bringing this Act into operation, and to remedy any transitional difficulties encountered in doing so, and for that purpose, may make regulations disapplying or varying any provision of this Act.

(2) Subject to subsection (3), this section is repealed on the date that is 2 years after the coming into force of this section and, on this section's repeal, any regulations made under it are also repealed.

(3) The Lieutenant Governor in Council, by regulation, may substitute for the date referred to in subsection (2) a date that is no later than 3 years after the coming into force of this section.

Part 10 — Consequential Amendments

BC Hydro Public Power Legacy and Heritage Contract Act

40 Section 1 of the BC Hydro Public Power Legacy and Heritage Contract Act, S.B.C. 2003, c. 86, is amended by repealing the definition of **"protected assets"*.***

41 Section 2 is repealed.

42 Section 4 (2) (a) is amended by striking out ", the *Hydro and Power Authority Act* and the *Transmission Corporation Act*;***" and substituting "***and the *Hydro and Power Authority Act*;***".***

43 The Schedule is repealed.

Environmental Assessment Act

44 Section 11 (2) (b) of the Environmental Assessment Act, S.B.C. 2002, c. 43, is amended by adding ", including potential cumulative environmental effects***" after "***assessment***".***

Financial Information Act

45 Schedule 1 of the Financial Information Act, R.S.B.C. 1996, c. 140, is amended by striking out "*Transmission Corporation Act****".***

Forest Act

46 Section 47.6 (2.11) (b) of the Forest Act, R.S.B.C. 1996, c. 157, as enacted by section 18 (c) of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, S.B.C. 2008, c. 20, is amended by striking out everything after "has received notification***" and substituting "***under section 79.1.***"***

47 Section 47.7 (f) (ii) is amended by adding "other than a forestry licence to cut issued under section 47.6 (2.11)***" after "***forestry licence to cut***".***

48 Section 47.72, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions

Standards) Statutes Amendment Act, 2008, is amended

> ***(a) in subsection (1) (f) by striking out "***a regulation made under section 151.6 (2).***" and substituting "***section 79.1.***", and***
>
> ***(b) in subsection (2) by striking out "***of harvest completion***" and substituting "***in accordance with section 79.1***" and by striking out "***a regulation made under section 151.6 (2)***" and substituting "***section 79.1.***"***

49 Section 47.73, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out everything after "gave the notification***" and substituting "***in accordance with section 79.1.***"***

50 Section 47.9, as enacted by section 22 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out "a regulation made under section 151.6 (2)***" and substituting "***section 79.1***".***

51 The following Division is added after section 79:

Division 4.1 — Miscellaneous

Order respecting notice

79.1 (1) During the term of an agreement under section 12, the minister may order that the agreement holder must notify the minister, in accordance with the requirements specified in the order, whether the agreement holder has abandoned or intends to abandon any rights the agreement holder has in respect of Crown timber that has been cut under the agreement but has not been removed from an area specified in the order.

(2) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has abandoned or intends to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy or otherwise deal with the Crown timber referred to in that subsection.

(3) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has not abandoned and does not intend to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy the Crown timber referred to in that subsection, if the minister is satisfied that a market exists for that Crown timber.

(4) A person to whom an order under this section has been given must comply with the order.

Freedom of Information and Protection of Privacy Act

52 Schedule 2 of the Freedom of Information and Protection of Privacy Act, R.S.B.C. 1996, c. 165, is amended by striking out the following:

Public Body:	British Columbia Transmission Corporation
Head:	Chair ***.***

Hydro and Power Authority Act

53 Section 1 of the Hydro and Power Authority Act, R.S.B.C. 1996, c. 212, is amended in the definition of "power" by adding "**, except in sections 12 (1) and 38 (2)," before "**includes energy***".***

54 Section 12 (1) is repealed and the following substituted:

(1) Subject to this Act and the regulations, the authority has the capacity and the rights, powers and privileges of an individual of full capacity and, in addition, has

(a) the power to amalgamate in any manner with a firm or person, and

(b) any other power prescribed.

(1.1) The authority's purposes are

(a) to generate, manufacture, conserve, supply, acquire and dispose of power and related products,

(b) to supply and acquire services related to anything in paragraph (a), and

(c) to do other things as may be prescribed.

(1.2) The authority may not engage in activities or classes of activities prescribed for the purposes of this subsection without obtaining an applicable approval as prescribed.

55 Section 32 is amended

(a) in subsection (7) (c) by adding "**section 32 and" before "**Division***",***

(b) in subsection (7) by adding the following paragraph:

(c.01) the *Clean Energy Act*; ***,***

(c) in subsection (7) (x) by adding "**44.1," after "**sections***", and***

(d) by repealing subsection (8).

56 Section 38 is amended by renumbering the section as section 38 (1) and by adding the following subsection:

(2) Without limiting subsection (1), the Lieutenant Governor in Council may make regulations

(a) prescribing powers for the purposes of section 12 (1),

(b) prescribing purposes of the authority for the purposes of section 12 (1.1), and

(c) for the purposes of section 12 (1.2), prescribing activities, classes of activities and approval requirements.

Transmission Corporation Act

57 The Transmission Corporation Act, S.B.C. 2003, c. 44, is repealed.

Utilities Commission Act

58 Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by repealing

the definitions of* "demand-side measure" *and* "government's energy objectives" *and substituting the following:

"British Columbia's energy objectives" has the same meaning as in section 1 (1) of the *Clean Energy Act*;

"demand-side measure" has the same meaning as in section 1 (1) of the *Clean Energy Act*; ***.***

59 Section 1 is amended by repealing the definition of* "transmission corporation"*.

60 Section 3 (2) is amended by striking out "*or*" at the end of paragraph (a) and by adding the following paragraph:

(a.1) any provision of the *Clean Energy Act* or the regulations under that Act, or ***.***

61 Section 5 (0.1) and (4) to (9) is repealed.

62 Section 28 is amended

(a) in subsection (1) by striking out "*90*" and substituting "*200*", and

(b) by adding the following subsections:

(2.1) If required to do so by regulation, the commission, in accordance with the prescribed requirements, must set a rate for the authority respecting the service provided under subsection (1).

(2.2) A requirement prescribed for the purposes of subsection (2.1) applies despite

(a) any other provision of this Act or any regulation under this Act, except for a regulation under section 3, or

(b) any previous decision of the commission.

63 Section 29 is amended by striking out "*90*" and substituting "*200*".

64 Section 43 (1.1) is repealed.

65 Section 44.1 is amended

(a) by repealing subsections (1) and (4), and

(b) by repealing subsection (8) (a) and (b) and substituting the following:

(a) the applicable of British Columbia's energy objectives,

(b) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***.***

66 Section 44.2 is amended

(a) in subsection (3) by striking out "*subject to subsections (5) and (6),*" and substituting "*subject to subsections (5), (5.1) and (6),*",

(b) in subsection (5) by adding "*filed by a public utility other than the authority*" after "*expenditure schedule*" and by repealing paragraphs (a) and (c) and substituting the following:

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, , and

(c) by adding the following subsection:

(5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

67 Section 46 is amended

(a) in subsection (3) by striking out "Subject to subsections (3.1) and (3.2),***" and substituting "***Subject to subsections (3.1) to (3.3),***",***

(b) in subsection (3.1) by adding "applied for by a public utility other than the authority***" after "***under subsection (3)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***, and***

(c) by adding the following subsection:

(3.3) In deciding whether to issue a certificate under subsection (3) to the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the certificate is consistent with the requirements under section 19 of the *Clean Energy Act*.

68 Section 58.1 (2) (a) (ii) is amended by striking out "or 125.1 (4) (f)***".***

69 Part 3.1 is repealed.

70 Section 71 is amended

(a) in subsection (2.1) by adding "filed by a public utility other than the authority***" after "***whether an energy supply contract***" and by repealing paragraphs (a) and (c) and***

substituting the following:

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the energy supply contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***,***

(b) by adding the following subsection:

(2.21) In determining under subsection (2) whether an energy supply contract filed by the authority is in the public interest, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the energy supply contract is consistent with the requirements under section 19 of the *Clean Energy Act*,

(d) the quantity of the energy to be supplied under the contract,

(e) the availability of supplies of the energy referred to in paragraph (d),

(f) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (d), and

(g) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (d). ***,***

(c) in subsection (2.5) by adding "with respect to a submission by a public utility other than the authority***" after "***under subsection (2.4)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the proposed contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, and ***, and***

(d) by adding the following subsection:

(2.51) In considering the public interest under subsection (2.4) with respect to a submission by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the proposed contract is consistent with the requirements under section 19 of the *Clean Energy Act*.

71 Section 125 (2) is amended by adding the following paragraph:

(e) requiring the commission to set a rate for the purposes of section 28 (2.1) and prescribing requirements for the purposes of that section.

72 Section 125.1 is amended

(a) by repealing subsections (2), (3) and (4) (a), (c), (d), (f) and (j) to (n), and

(b) in subsection (4) (e) by adding "and***" at the end of subparagraph (ii), by striking out*** ", and***" at the end of subparagraph (iii) and by repealing subparagraph (iv).***

73 Section 125.2 (3) is amended by striking out "transmission corporation***" and substituting "***authority***".***

Wildfire Act

74 Section 7 of the Wildfire Act, S.B.C. 2004, c. 31, is amended

(a) by adding the following subsections:

(2.1) A person who is in a prescribed class of persons and who carries out an industrial activity or a prescribed activity on an area must, within the prescribed period and to the prescribed extent, abate a fire hazard on the area.

(2.2) A person referred to in subsection (2) is not required to abate a fire hazard on an area if a person referred to in subsection (2.1) is required to abate the fire hazard. ***, and***

(b) in subsection (3) by striking out "subsection (2)***" in both places and substituting "***subsections (2) and (2.1)***" and by adding "***applicable***" before "***person***".***

75 Section 43 (3) is amended by striking out "section 7 (2) or (4),***" and substituting "***section 7 (2), (2.1) or (4),***".***

76 Section 72 (2) (g) is repealed and the following substituted:

(g) respecting the abatement of fire hazards, including, without limitation,

(i) prescribing classes of person, activities and time periods for the purposes of section 7 (2.1), and

(ii) specifying, for the purposes of section 7 (2.1), the extent to which a fire hazard must be abated, .

Commencement

77 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 20	July 5, 2010
3	Section 42	July 5, 2010
4	Section 45	By regulation of the Lieutenant Governor in Council
5	Section 52	By regulation of the Lieutenant Governor in Council

6	Section 55 (d)	July 5, 2010
7	Section 57	July 5, 2010
8	Section 59	July 5, 2010
9	Section 73	July 5, 2010

Schedule 1

Heritage Assets

Those generation and storage assets commonly known as the following:

Aberfeldie

Alouette

Ash River

Bridge River

Buntzen/Coquitlam

Burrard Thermal

Cheakamus

Clowhom

Duncan

Elko

Falls River

Fort Nelson

G. M. Shrum

Hugh Keenleyside Dam (Arrow Reservoir)

John Hart

Jordan

Kootenay Canal

La Joie

Ladore

Mica, including units 1 to 6

Peace Canyon

Prince Rupert

Puntledge

Revelstoke, including units 1 to 6

Ruskin

Site C

Seton

Seven Mile

Shuswap

Spillimacheen

Stave Falls

Strathcona

Waneta

Wahleach

Walter Hardman

Whatshan

Schedule 2

Prohibited Projects

The projects of the authority, as set out in appendix F-8 of the authority's long-term acquisition plan, exhibit B-1-1, filed with the commission on June 12, 2008, are prohibited projects for the purposes of section 10, in particular, the following projects identified in appendix F-8:

(a) Murphy Creek;

(b) Border;

(c) High Site E;

(d) Low Site E;

(e) Elaho;

(f) McGregor Lower Canyon;

(g) Homathko River;

(h) Liard River;

(i) Iskut River;

(j) Cutoff Mountain;

(k) McGregor River Diversion.

Explanatory Note

This Bill sets out British Columbia's energy objectives, requires the British Columbia Hydro and Power Authority to submit an integrated resource plan describing what it plans to do in response to those objectives, and requires the authority to achieve electricity self-sufficiency by the year 2016. The Bill also prohibits certain projects from proceeding, ensures that the benefits of the heritage assets are preserved for British Columbians, provides for the establishment of energy efficiency measures and establishes the First Nations Clean Energy Business Fund. The Transmission Corporation and the authority are also to be unified under this Bill.

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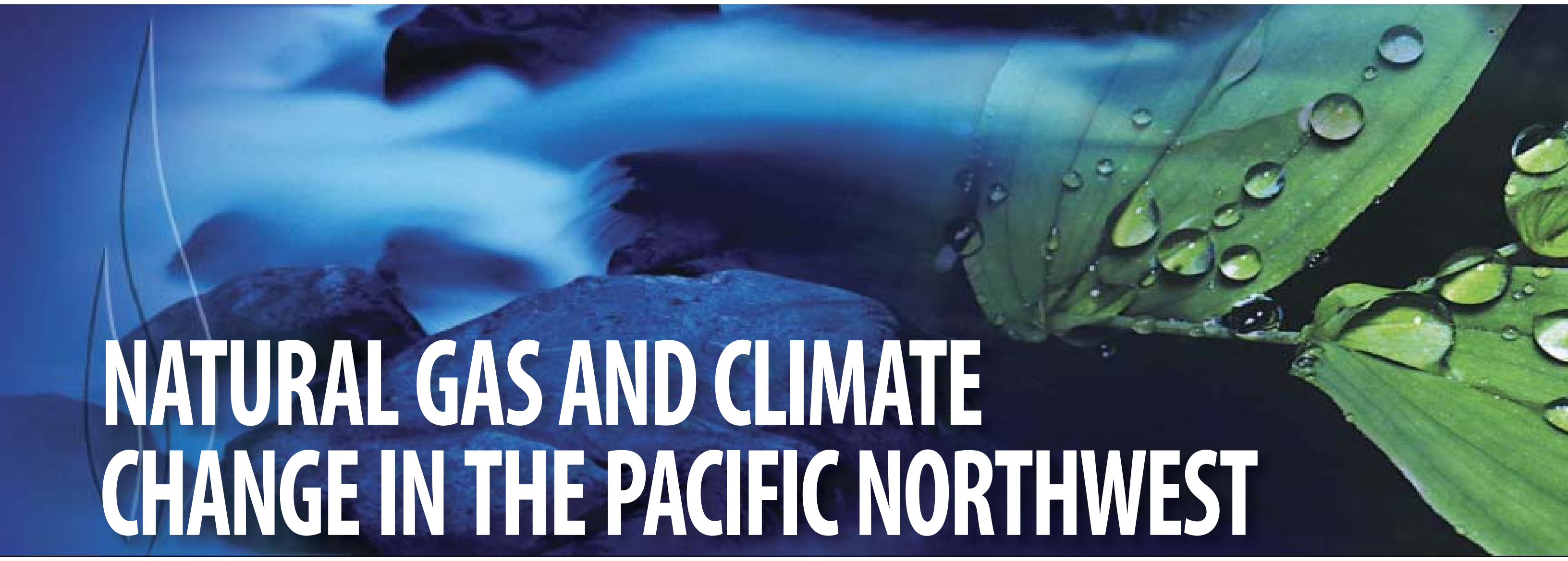

NATURAL GAS AND CLIMATE CHANGE IN THE PACIFIC NORTHWEST

IN THIS ISSUE

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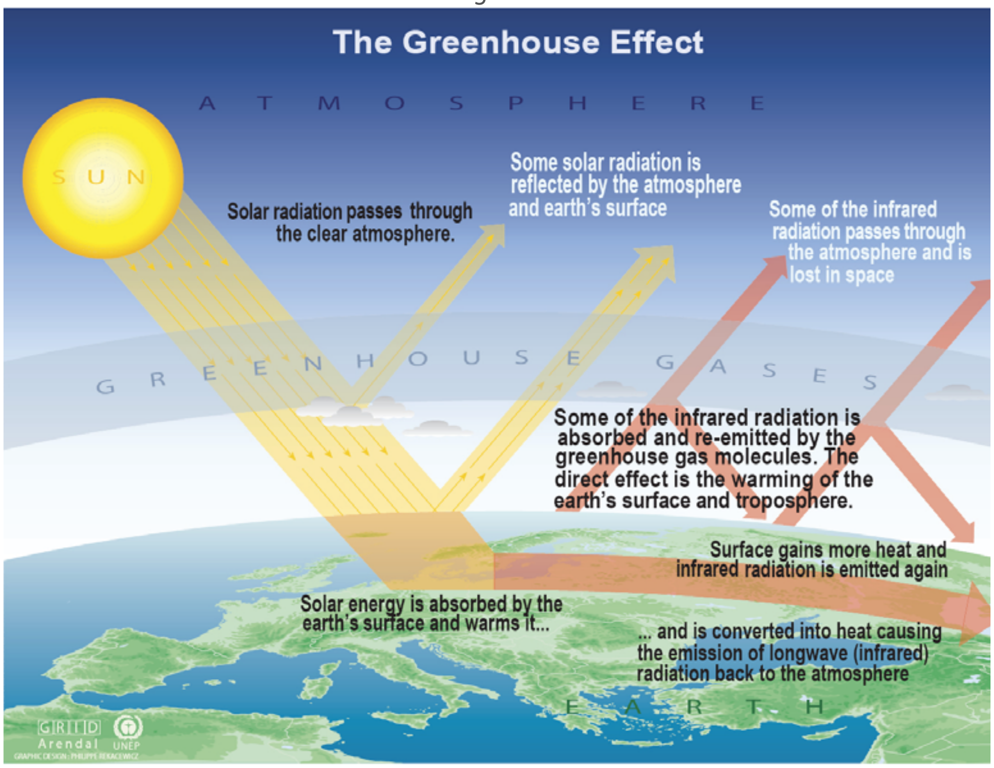
NWGA Policy Principles relating to climate change initiatives
What we can do today to protect our environment

Growing concern about global climate change is triggering change in the political climate. As decision makers craft near- and longer-term policies aimed at reducing greenhouse gas (GHG) emissions, consideration must be given to the vital role of natural gas in the equation. Because it is the cleanest burning of all fossil fuels, natural gas is a centerpiece in regional, national and international efforts to address climate change.

An analysis of proposed U.S. Climate Change legislation (S.280) recently released by the Natural Gas Council (NGC) - representing every segment of the U.S. natural gas industry - confirms as much. In a related press release dated October 3, 2007, the NGC said, "[We] firmly believe that natural gas will be a critical component in achieving greenhouse gas emission reductions under any climate change legislation."



Sources: Okanagan University College in Canada, Department of geography, University of Oxford, school of geography; United State Environnental Protection Agency, Washington; Climate change 1995, The Science of Climate Change, contribution of working group 1 to the second assessment report of the intergovernmental panel on climate change, UNET and WMO, Cambridge University Press, 1996.

The Pacific Northwest is in the vanguard with several states and provinces having recently enacted climate change policies. Because natural gas is a valuable resource and such an important part of the region's economy, regional policymakers must ensure that it is utilized as effectively as possible. The region must retain and secure additional access to abundant and diverse sources of supply as climate change policies increase regional demand for natural gas. It must also ensure that the associated transmission, storage and distribution infrastructure can grow as necessary.

This white paper explores the role of natural gas in addressing climate change, some practical steps consumers across the region can take to reduce their carbon emissions and the policy principles adopted by the NWGA Board to guide our approach to climate change-related policy initiatives.

NATURAL GAS AND CLIMATE CHANGE IN THE PACIFIC NORTHWEST

THE ROLE OF NATURAL GAS IN ADDRESSING CLIMATE CHANGE

In order to develop solutions that both reduce our contribution to climate change and sustain our energy needs, we need to make full use of our current infrastructure and resources. This includes continuing to improve technology and emphasize energy efficiency. It also includes converting uses from fuel oil and coal to natural gas – the cleanest of all fossil fuels – where it makes sense to do so.

Natural gas serves as a blue bridge to a greener world. When burned natural gas produces mostly CO_2 and water vapor – the same compounds that humans produce when we exhale. Fuel oil and coal both contain more nitrogen and sulfur along with a higher carbon ratio resulting in higher levels of harmful emissions, including carbon, nitrogen oxides (NO_x) and sulfur dioxide (SO_2), as well as ash particles that can cause or worsen many respiratory illnesses.

By comparison, natural gas emits very little NO_x or SO_2, virtually no ash, and about half as much CO_2 as coal according to the U.S. EPA (US Greenhouse Gas Inventory Reports - Annex 2, April, 2007). This makes natural gas an ideal fuel source to help reduce CO_2 being transmitted into the atmosphere – as recognized by the United Nations Intergovernmental Panel on Climate Change (IPCC) and others.

HUMAN-CAUSED GREENHOUSE GASES

Carbon dioxide (CO_2) may account for as much as 84 percent of GHG emissions, according to the Energy Information Administration. Nearly all atmospheric CO_2 from human sources comes from burning fossil fuels.

Methane (CH_4) is emitted during production and transport of fossil fuels. However, the largest methane emission sources are cattle and other livestock, biomass burning, decaying organic waste in landfills, and biological activity in rice paddies and swamps.

Nitrous Oxides (N_2O) causes thinning in the Earth's protective ozone layer where it can remain for about 150 years due to its extremely stable properties. Fossil fuel and biomass combustion during industrial, agricultural and forestry activities is the largest contributor of these emissions.

Fluorinated Gases (hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride) are powerful synthetic GHGs emitted from industrial process such as magnesium, aluminum and semiconductor manufacturing. Fluorinated gases are sometimes used as substitutes for ozone-depleting substances (e.g., chlorofluorocarbons) in refrigeration, air conditioning and aerosols. Although typically emitted in smaller amounts, they are sometimes referred to as High Global Warming Potential (High GWP) gases.

ENVIRONMENTAL ENHANCEMENT: TAKING FULL ADVANTAGE OF NATURAL GAS

Natural gas is already popular as a clean source of fuel for generating electricity. In fact, natural gas is the fuel for the vast majority of new electrical generating capacity built in the U.S. over the last fifteen years. During the past two decades, increased use of natural gas helped reduce the level of GHG emissions relative to the United States gross domestic product, according to the Energy Information Administration. Direct use of natural gas – in home heating, water heating and stovetops – is the most efficient, cost-effective and environmentally beneficial way to use it.

Increasing our use of compressed natural gas as a transportation fuel for both heavy and light duty applications will also contribute to reducing our carbon footprint. Significant reductions in CO_2, NO_x and other emissions can be achieved by substituting natural gas for gasoline or diesel fuels not only in passenger vehicles and buses, but also in industrial equipment, business and transport fleets, port applications, ferries and more.

The technology for natural gas-powered vehicles has existed for many years, and although several factors have served to slow its adoption, advances continue to be made. Meanwhile, businesses and government agencies continue to establish and expand CNG refueling infrastructure and increase their use of natural gas for powering their buses, delivery vans, taxis, postal vehicles and the like. In addition, ports are reducing emissions by fueling on-board ship generators with natural gas instead of diesel.

NWGA CLIMATE CHANGE PRINCIPLES

In state and provincial capitals across the Pacific Northwest, policymakers are addressing the region's role in mitigating greenhouse gas (GHG) emissions. The region's natural gas industry remains a committed partner in this ongoing effort. Our industry's effectiveness on this issue, however, largely depends upon how well policymakers understand the role that natural gas can play in tackling climate change.

> **"We don't need to wait for revolutionary technology or expensive government programs to make progress reducing greenhouse gases. Using gas directly in high-efficiency equipment can reduce our carbon footprint now."**
>
> Mark Dodson
> CEO of Portland based NW Natural

The following summarizes the Northwest Gas Association's policy recommendations to address climate change by revamping energy use, developing and implementing effective measures that embrace the unique role of natural gas in furthering a cleaner, healthier environment and by ensuring that the region retains access to abundant and diverse sources of natural gas. We ask Northwest policymakers at all levels – local, state/provincial and federal – to incorporate the following principles as they craft and implement climate change policies across the region:

First and foremost, the NWGA asserts that coordinated emissions regulation should occur at the federal level in the U.S. and Canada in order to prevent regional regulatory disparities and competing compliance standards.

In addition, climate change policies must recognize that significant changes in energy use cannot happen overnight – time must be allowed to build capital-intensive new infrastructure and for the economy to develop and provide cost-effective, efficient new fuels and technologies. Policymakers must begin now while the issues can still be addressed thoughtfully.

Climate change policies should promote energy efficiency first - Reducing the amount of energy used is the most effective and least expensive method of controlling emissions and conserving resources. Natural gas utilities have a long history of helping their customers to use energy wisely and reduce emissions and will continue their efforts in this regard. Related policies should:

- Support and promote market-based, cost-effective energy efficiency measures.
- Support the development and cost-effective deployment of energy efficiency technologies. For instance, NWGA members are developing new technologies for home and business that allow consumers to more accurately track their energy use and costs so that they can improve both and contribute to the goal of conserving energy.
- Rate structures should promote energy efficiency without creating a disincentive for the utility. Innovative strategies benefiting consumers and the environment have proven effective, both in the Northwest and elsewhere.

Climate change policies should promote the right fuel for the right use - Applying this principle will maximize the benefits of the energy used. For instance, the direct use of natural gas is the best way to take full advantage of the energy contained in and environmental gain from using natural gas. For example, new natural gas-fired furnaces are 90-95 percent efficient in converting gas to heat. Related policies should:

- Promote the right energy source for the right use. For instance, high-efficiency end-use natural gas applications such as residential furnaces, tank and instantaneous tankless water heaters, commercial boilers, industrial furnaces and combined heat and power systems are all applications where natural gas is more energy efficient than equivalent electric systems.

NWGA CLIMATE CHANGE PRINCIPLES

- Promote increased energy efficiency in all appliances, tools and vehicles. Energy efficiency should be a central goal of how we build homes and offices, design neighborhoods and cities, and live our daily lives.

- Reflect the high efficiency of natural gas transportation and delivery systems (less than 1 percent loss compared to 10 percent loss in electric transmission and delivery), making natural gas even more environmentally attractive.

Climate change policies should utilize market forces to encourage use of the cleanest resources – Natural gas emits about 45 percent less carbon dioxide (CO_2) per million Btus than coal and 30 percent less than fuel oil. Even though natural gas fuels more than 90 percent of the electric generating capacity that has been added over the past 15 years, coal still accounts for more than 50 percent of our overall electric generation, while natural gas provides only 17 percent. A properly designed regulatory regime will result in lower CO_2 production as natural gas replaces higher emission fuels. Related policies should:

- Accelerate the development of new technologies to ensure North America's vast energy resources remain viable in a carbon-constrained context, and to help reduce our dependence on foreign energy sources. Examples of developing technologies include gasification of coal and bitumen, CO_2 sequestration and more efficient generators.

- Promote the development of additional low-greenhouse gas emitting electrical generation in order to enhance fuel diversity and reduce our reliance on natural gas and other carbon fuels. Examples include solar, wind, geothermal, nuclear, wave, and other renewable resources.

- Be structured to ensure that they do not divert energy consumers from more efficient fuels sources such as natural gas to less efficient and more polluting energy forms.

Climate change policies must provide for additional natural gas supplies – Displacing high-carbon fuels with natural gas will contribute to a reduction in GHG emissions across the region and is likely to drive additional demand for natural gas in the Pacific Northwest. The regional demand for natural gas is projected to increase by almost 7.2 percent over the next five years and could grow by more than 30 percent over the next two decades. Gas required to serve electric generation in the Pacific Northwest is projected to grow by more than 12 percent over the next five years. Meeting the region's energy needs as well as its environmental and economic goals will require greater access to domestic and international gas supplies. Related policies must:

- Support removing the barriers to access new supplies (e.g. exploration moratoria, land use restrictions, permitting delays, redundant oversight).

- Support the development of infrastructure that enhances our region's access to a variety of abundant supply resources (e.g. transmission pipelines, storage facilities).

- Acknowledge that direct access to liquefied natural gas (LNG) imported from overseas will directly benefit gas users served by NWGA member companies through enhanced supply availability and reliability.

- Encourage research and development of unconventional resources such as coal-bed methane, natural gas from shales, methane hydrates and bio-gas from landfill and dairy operations.

> **"Unless policymakers adopt policies that encourage ample, environmentally responsible production of the natural gas we need to meet climate change goals and keep us globally competitive, future generations of American businesses and families will pay a hefty price."**
>
> David Parker, CEO
> American Gas Association

NATURAL GAS AND CLIMATE CHANGE IN THE PACIFIC NORTHWEST

SUPPLY RESPONSE REQUIRED

According to the EIA, there are currently more than 6,000 trillion cubic feet (Tcf) of proven (can be produced with today's technology at today's prices) natural gas reserves around the world – more than sixty years of production at current usage rates. And more will become available as technology improves.

In order to compensate for increased natural gas demand that is likely to occur across North America as a result of proactive climate change policies, we must expand access to available natural gas supplies. Current policies and restrictions compromise our ability to take full advantage of the proven environmental benefits of natural gas in addressing climate change.

In testimony before the U.S. House Committee on Energy and Commerce in March, 2007, the American Gas Association representatives noted that supply constraints have driven natural gas prices to triple and quadruple their 2000 levels. "Any climate change program must include measures to increase the availability of natural gas to support its important role in reducing domestic greenhouse gases," they testified.

The Pacific Northwest is blessed by its proximity to prolific natural gas production areas but it faces increasing competition from other regions of North America for the supplies upon which it depends. That fact coupled with its leadership on enacting climate change policies – policies that promote the use of natural gas – combine to make encouraging access to new sources of supply a regional priority.

For instance, building a liquefied natural gas (LNG) receiving terminal in the Pacific Northwest (U.S. and Canada) will promote supply abundance and diversity and may help to preserve the region's low-cost energy advantage. Building new energy infrastructure like an LNG import facility can be compared to the investments our region made in hydropower more than seventy years ago – an endowment that continues to pay dividends today. In addition, restrictions on exploring for new gas reserves across North America – including those located offshore – should be loosened, and the region should seek direct access to frontier gas supplies (e.g. Alaska, Mackenzie) when they become available.

REDUCING OUR CARBON FOOTPRINT BEGINS AT HOME

We can start reducing greenhouse gas emissions today with easy solutions found right in our basements. The direct use of highly efficient natural gas in water heaters, furnaces and other appliances can help cut carbon dioxide emissions by thousands of tons each year.

Electric utilities continue to turn to clean-burning natural gas for electricity generation as an environmentally-friendly alternative to coal and fuel oil. But the direct use of natural gas in appliances brings even greater benefits to the consumer and our planet.

Recently, NW Natural of Oregon examined the full carbon footprint associated with an all-electric house. We replaced the appliances with a natural gas furnace, water heater, cook top and dryer, using carefully vetted assumptions regarding technology and efficiency. We found that using these appliances reduced greenhouse gas emissions by more than 20 percent compared to their electric counterparts. In areas served by more coal-dependent electric utilities, the carbon reduction can be greater than 50 percent.

These are changes that we can implement today. We don't have to wait for future inventions or new environmental programs to get started. All it takes is a gas line and a trip to the appliance store.

By Bill Edmonds
Director - Environmental Policy & Sustainability,
of Portland, Oregon based NW Natural.
Condensed from "Reducing our Carbon Footprint Begins in the Basement"
[American Gas, August-September 2007]

MITIGATING CLIMATE CHANGE WITH EFFECTIVE PUBLIC POLICY

We may never know everything about the dynamics of climate change, but we do know enough to take action. Energy companies, scientists, and government leaders are expanding policies to more fully address the issue.

At the federal level, the U.S. and Canada continue developing policies that encourage emission reduction. In the U.S. for example, some $35 billion has been invested (via tax incentives) to promote cleaner energy sources and emission-reducing technologies. A number of proposals have been introduced in the past year, all aimed at enacting even more comprehensive remedies.

In Canada, the federal government released its Regulatory Framework for Air Emissions. The Framework expects industrial emitters to reduce emissions intensity by 18 percent between 2008 and 2010 and then further reduce intensities at an increasing rate beginning in 2010. The Framework's overall goal is real reductions of 150 million tons of GHG emissions by 2020.

NWGA
NORTHWEST GAS ASSOCIATION

NATURAL GAS AND CLIMATE CHANGE IN THE PACIFIC NORTHWEST

Along with California, Pacific Northwest policymakers are at the cutting edge. Washington and Oregon recently enacted standards requiring that significant proportions of electricity be generated by renewable resources. Both states also adopted standards that limit GHG emissions from any new electric generation resources. Idaho enacted a temporary moratorium on mercury emissions, precluding the construction of any new coal-fired generation there.

British Columbia has announced its intent to reduce GHG emissions by 33 percent from current levels by 2020 (among other actions). The Province of Alberta has put in place GHG emissions intensity targets effective July 1, 2007, and is one of the first jurisdictions in the world to mandate such targets.

> **"Puget Sound Energy's future is both windier and gassier."**
>
> Steve Reynolds
> CEO of Bellevue based Puget Sound Energy
> as delivered to the NWGA Spring Energy
> Conference May 2007.

In addition, several states and provinces across the region are participating in the Western Climate Initiative, a regional effort to establish common GHG reduction targets and strategies and a regional carbon trading market.

VITAL CONSIDERATIONS

In order for public policy to be truly effective long-term, policymakers should consider the following:

- Controls on GHG emissions need to be attained primarily by promoting conservation and energy efficiency.

- Competing fuels should be treated equally and in a manner consistent with their contributions and economic impact. All economic sectors must play a role in emissions reduction. Policies and regulations that divert consumers to less efficient, more-polluting energy sources will only serve to worsen the impact on the environment.

- Expanding the use of natural gas, particularly for direct uses such as home heating and appliances, should be encouraged. Ways to promote this include tax credits, direct subsidies, and/or allowance mechanisms that recognize the significant CO_2 reduction potential of natural gas. New policies must also allow increased access to natural gas supplies and include regulatory changes that will help utilities to encourage greater energy efficiency without incurring debilitating financial losses. (*See NWGA Climate Change Principles for expanded discussion of these points.*)

ACTION	ANNUAL CO_2 REDUCTIONS (Average car miles driven*)
When replacing your car, buy one that gets 3 miles more per gallon.	3,000 miles driven
Switch 1 "all electric" home to 1 "all natural gas" home.	2,320 miles driven
Set your thermostat 2° higher in summer, 2° lower in winter.	2,000 miles driven
Replace regular light bulbs with compact fluorescent lamps.	300 miles driven

(*Assumes 20 miles per gallon)

CONCLUSION

Natural gas is a resource that is immediately available to help significantly reduce GHG emissions. The NWGA intends to be fully engaged in discussions with regional stakeholders concerning the role of the natural gas industry in addressing challenges associated with managing GHG emissions and climate change. Furthermore, the industry will participate constructively in regional efforts to craft environmentally sensitive and economically sensible energy policies.

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NWGA
NORTHWEST GAS ASSOCIATION

BC Bioenergy Strategy

Growing Our Natural Energy Advantage

BRITISH COLUMBIA
The Best Place on Earth

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Honourable Gordon Campbell
Premier of British Columbia

"The Province is addressing these challenges head on. The BC Bioenergy Strategy will help turn existing challenges into new opportunities – for both forestry and agriculture."

Human activity has changed our world. It has led to numerous advances – from instant power to airline travel to the farthest reaches of the globe. For a long time, these advances carried with them the unseen cost of rising greenhouse gas emissions, which has led to the monumental challenges of global warming and climate change.

The Province is addressing these challenges head on. The BC Bioenergy Strategy will help turn existing challenges into new opportunities – for both forestry and agriculture.

The BC Bioenergy Strategy sets us on a path to diversify rural economies and turn adversity into opportunity by recovering maximum value from all our forests and creating new economic opportunities for mountain pine beetle damaged timber through conversion into bioenergy.

Bioenergy provides new opportunities for agriculture. It will be developed from B.C.'s landfills, crop residues and agricultural wastes.

Bioenergy is a positive, practical approach that will involve all regions and all British Columbians in preparing for a low-carbon future. The bioenergy we generate from our abundant resources in B.C. can help meet greenhouse gas reduction targets at home and in other jurisdictions, creating enduring economic benefits.

This strategy builds upon a solid foundation of expertise, innovation and experience. Many B.C. forest companies already convert wood residues into electricity and heat used in their mills, and some supply surplus amounts into the power grid. Established community energy projects and landfill methane-capture systems demonstrate the success and commitment to bioenergy that exists in B.C. right now.

With the support of government, industry and partners in the Western Climate Initiative, this strategy will help launch British Columbia as a carbon-neutral energy powerhouse in North America.

The BC Bioenergy Strategy will help B.C. achieve its targets for zero net greenhouse gas emissions from energy generation, improved air quality, electricity self-sufficiency and increased use of biofuels.

Bioenergy holds the promise of innovation, investment and job creation. All are within our grasp if we're willing to look to the future and embrace the changes that are upon us.

Honourable Gordon Campbell
Premier of British Columbia

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

Honourable Rich Coleman
Minister of Forests and Range

Honourable Pat Bell
Minister of Agriculture and Lands

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

Honourable Rich Coleman
Minister of Forests and Range

Honourable Pat Bell
Minister of Agriculture and Lands

HIGHLIGHTS

CLEANER, GREENER

Bioenergy is energy derived from organic biomass sources – such as trees, agricultural crops, food processing and agricultural wastes and manure. Biomass can be generated from logging, agriculture and aquaculture, vegetation clearing and forest fire hazard areas. When used for energy, biomass such as organic waste, wood residues and agricultural fibre is considered clean or carbon neutral because it releases no more carbon into the atmosphere than it absorbed during its lifetime. When used to replace non-renewable sources of energy, bioenergy reduces the amount of greenhouse gases released into the atmosphere.

The BC Bioenergy Strategy will help British Columbia and other places in North America reduce greenhouse gas emissions and strengthen our long-term competitiveness and electricity self-sufficiency. Bioenergy is absolutely critical to achieving B.C.'s climate goals and economic objectives. It turns the challenges of the mountain pine beetle infestation into new opportunities and looks to future bioenergy technologies. This strategy directly supports the commitments made in the BC Energy Plan and is a key contributor to helping our partners in the Western Climate Initiative achieve their emission reduction goals.

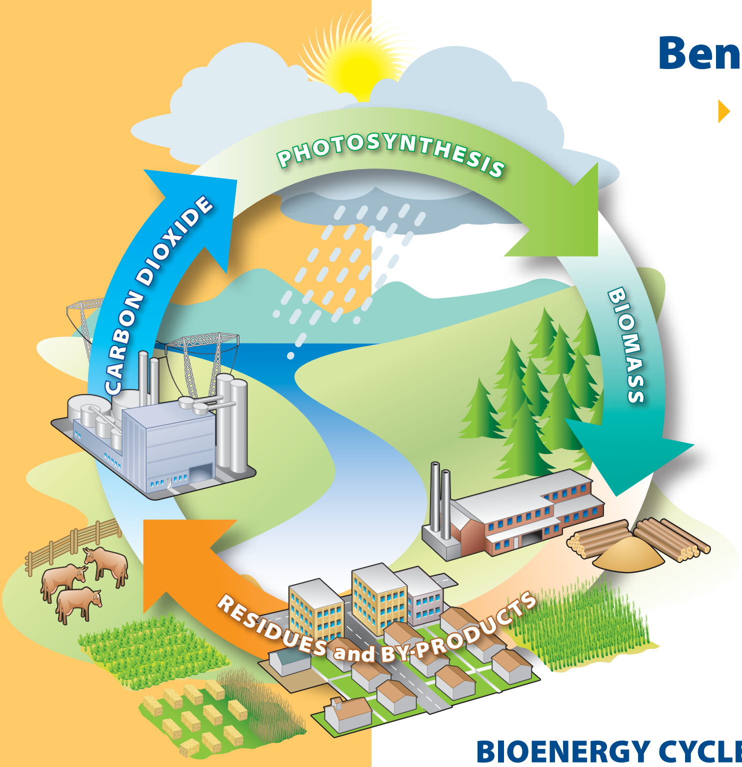
Building Opportunities for Rural British Columbia

British Columbia's bioenergy assets include top researchers, innovative companies, committed partners, forward-thinking communities, and half of the entire country's biomass electricity-generating capacity.

- Establish $25 million in funding for a provincial Bioenergy Network for greater investment and innovation in B.C. bioenergy projects and technologies.
- Establish funding to advance provincial biodiesel production with up to $10 million over three years.
- Issue a two-part Bioenergy Call for Power, focusing on existing biomass inventory in the forest industry.

Benefits for British Columbians

- We will aim for B.C. biofuel production to meet 50 per cent or more of the province's renewable fuel requirements by 2020, which supports the reduction of greenhouse gas emissions from transportation.
- We will develop at least 10 community energy projects that convert local biomass into energy by 2020.
- We will establish one of Canada's most comprehensive provincial biomass inventories that creates waste to energy opportunities.



BIOENERGY CYCLE

Developing Our Bioenergy Resources

British Columbia is world-renowned for its plentiful natural resources and strong environmental values. Through the BC Bioenergy Strategy, British Columbia will take its proven track record one step further. We will develop the province's bioenergy resources to enhance both the environmental and economic benefits for the people who live here. Next steps include:

- Collaborate with the Western Climate Initiative and the Pacific NorthWest Economic Region.
- Create First Nations bioenergy opportunities.
- Require methane capture from our largest landfills.
- Utilize waste wood from phased-out beehive burners to produce clean energy.
- Provide energy providers with information to develop new opportunities.
- Support wood gasification research, development and commercialization.

WHAT IS BIOMASS?

Biomass is renewable organic matter like crops, trees, wood chips, aquatic plants, manure and municipal waste. British Columbians produce biomass from daily activities. Biomass can take the form of organic garbage, yard and garden waste, sewage, and wood from demolition and construction sites.

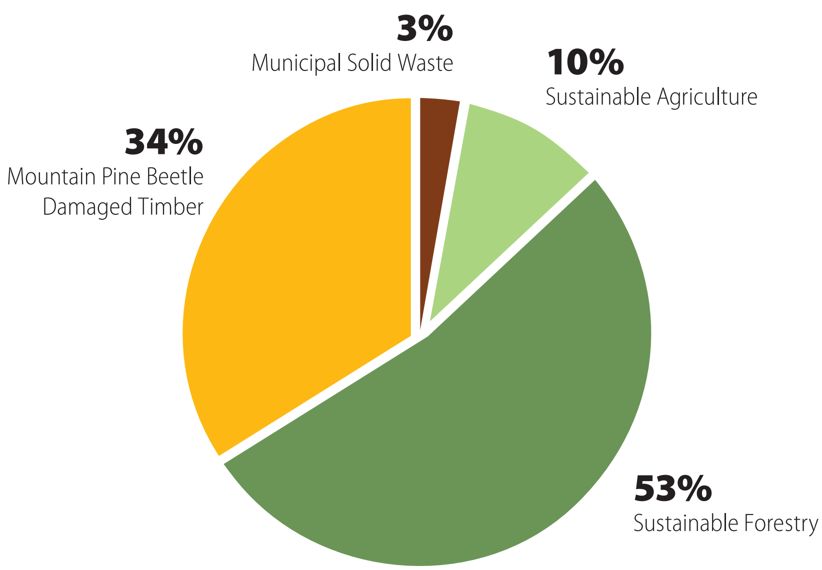
The province's main sources of biomass come from forest and agricultural activities. Food processing, aquaculture and other industries also produce large amounts of biomass.

Biomass can be used to produce heat and electricity, liquid and gaseous fuels (such as ethanol from grain and cellulose, biodiesel from oilseed and waste greases and biogas from anaerobic digestion), solid fuels (pellets and briquettes), and various other products.

British Columbia has 50 per cent of the biomass electricity-generating capacity of the entire country within our province.

B.C.'s Biomass Resources

British Columbia is committed to developing our abundant natural resources in an environmentally responsible manner. Through the implementation of the BC Bioenergy Strategy, Government will create new economic opportunities for forestry, agriculture, municipalities and First Nations communities. It will establish British Columbia as the hub of a global supply network of bioenergy resources, technologies and services.



Sustainable Forestry
This includes forest residues from logging practices, road clearing and other forestry activities. Site preparation, early tree removal and tree stand establishment could increase forest residues and be a source of biomass.

Mountain Pine Beetle Damaged Timber
The increased annual allowable cut to remove beetle-killed timber and non-recoverable pine are temporary sources of biomass, which will be available for approximately 20 years.

Sustainable Agriculture
Crop residues that are not utilized, which could include stalks, husks, straw and other post-harvest fibre, are available as a biomass source. Crops grown for biodiesel and ethanol production may include grain and canola. In future, livestock manure and dedicated crop growth are potential agricultural sources for biomass.

Municipal Solid Waste
Municipal landfills contain biomass that can become a source of fuel through landfill gas collection or direct combustion.

Canada has approximately seven per cent of the world's land mass, and 10 per cent of its forests. Unused biomass from Canada's forestry and farming operations that is not otherwise required for soil health or ecosystem restoration could provide as much as 27 per cent of our national energy needs.

Biomass Supply Estimates

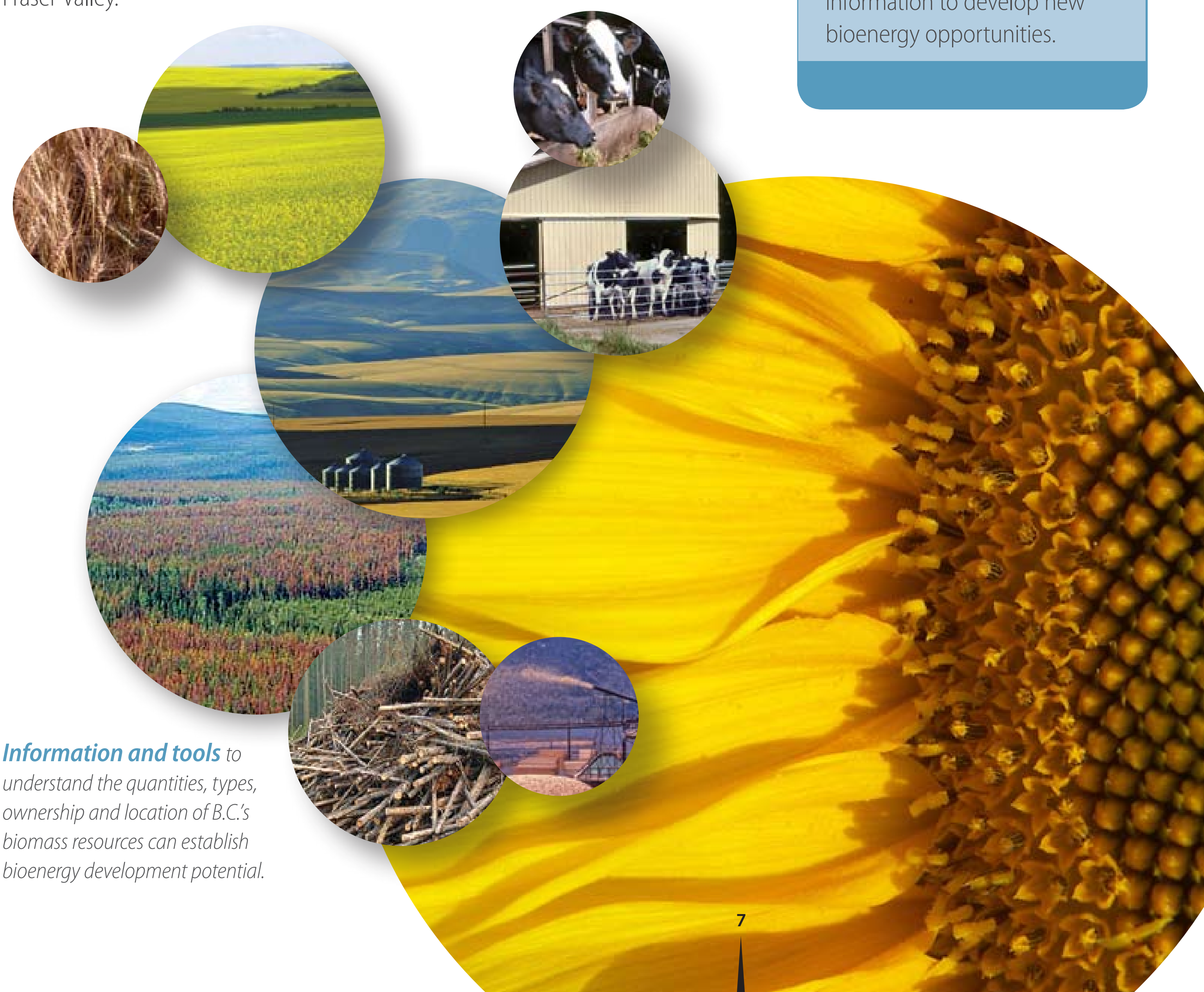
The Ministry of Forests and Range has begun work on wood Biofuel Supply Estimates. These supply estimates, highlight the bioenergy potential of different regions and can assist independent power producers and other energy developers in evaluating bioenergy opportunities from wood.

The Ministry of Agriculture and Lands is also developing an inventory mapping system to chart the volume, availability and geographic distribution of agricultural and agri-food by-products, starting with the Fraser Valley.

NEXT STEPS

A comprehensive inventory of the province's biomass resources will:

- Total the approximate volume of biomass available.
- Consolidate information and make it available in a user-friendly, easily accessed, online format.
- Provide energy producers with information to develop new bioenergy opportunities.



Information and tools *to understand the quantities, types, ownership and location of B.C.'s biomass resources can establish bioenergy development potential.*

Government and its partners will collaborate to develop B.C. bioenergy projects utilizing energy from wood waste, agriculture, renewable fuels and municipal waste.

Energy from Wood Waste

The opportunities to use both wood waste and mountain pine beetle damaged timber are endless. The City of Revelstoke is a leader in bioenergy. Wood waste from a local sawmill fuels a biomass boiler that enables the municipality to recover heat in the form of low pressure steam for drying lumber at the sawmill and providing hot water to a community energy system for buildings in the downtown core. The Revelstoke community energy project, in operation since 2005, increases energy efficiency, reduces wood waste from sawmills and improves local air quality.

Energy from Agriculture

Bioenergy presents exciting economic prospects for B.C.'s agriculture sector. The development of biofuels from grains, oilseeds, waste fats and greases may better exploit unused crop residues and agricultural by-products. At the same time, bioenergy has the potential to address animal manure and other waste management challenges.

As technology advances, biofuels will be produced from an even broader range of sources, such as algae, straw and plants that thrive in less fertile regions. These opportunities will help balance the development of bioenergy from agriculture with global food requirements.

The Fraser Valley, North Okanagan, Cariboo, Northeast B.C. and Northwest B.C. have an abundance of livestock facilities which could produce a continuous supply of feedstock for anaerobic digestion. Anaerobic digestion uses bacteria to convert organic waste into a biogas composed primarily of methane and carbon dioxide.

Government is funding an Anaerobic Digestion Feasibility Study to explore long-term bioenergy opportunities in rural regions throughout B.C.

Energy from Renewable Fuels

Government has set out to establish a low carbon fuel standard for British Columbia and is committed to implementing a five per cent average renewable fuel standard for diesel and to increasing the ethanol content of gasoline to five per cent by 2010. Farmers in the Peace Region stand to benefit from rising demand for grain used in ethanol production. A study completed in April 2007 for the B.C. Grain Producers Association shows potential for a 22-million-litre-per-year biodiesel production facility in the area using 56,000 tonnes of canola.

BIOENERGY CALL FOR POWER

BC Hydro will issue a two-part Bioenergy Call for Power early in 2008. This call will follow up on the March 2007 Request for Expressions of Interest for power production to convert underutilized wood into electricity.

The Bioenergy Call for Power will provide communities that are dependent on forestry and agriculture with new opportunities to partner with industry, First Nations and government to maximize economic benefits and improve air quality.

For further information visit **www.bchydro.com/2007/bioenergy**

BIODIESEL PRODUCTION

The Province will provide up to $10 million in funding over three years to encourage the development of biodiesel production in B.C. This will help diversify rural economies, improve competitiveness for B.C. biodiesel producers and provide new clean energy opportunities.

Energy from Municipal Waste

Turning municipal waste into green energy offers endless potential. The Hartland Landfill near Victoria captures landfill gases through a series of underground pipes. The gas is collected, then cooled, compressed and transported to a generating facility where it creates enough electricity for about 1,400 homes.

A similar system at Vancouver's Delta landfill can generate up to 50 gigawatt hours of power and provides heat to local greenhouses. The SEEGEN project, owned by the Greater Vancouver Regional District, incinerates waste to produce up to 125 gigawatt hours of power and low pressure steam for use in a nearby paper recycling plant.

NEXT STEPS

- The Province will develop legislation to phase in requirements for methane capture at landfills, the source of about nine per cent of B.C.'s greenhouse gas emissions. This methane could be used for clean energy.
- The Province will collaborate to streamline the regulatory and permitting environment and address the current waste management challenge posed by agricultural residues such as animal manure.
- The Province will develop regulatory measures to eliminate beehive burners, which will help divert those wood residues to higher value, lower pollutant bioenergy production.
- The Province will promote wood pellet production and facilitate market development opportunities within the province and around the world.
- The Province will improve access to wood fibre feedstocks for the generation of heat and power in collaboration with the forest and energy industries, utilities and provincial government partners.
- The Province will review the *Safety Standards Act* Power Engineers, Boiler, Pressure Vessel and Refrigeration Safety Regulation to accelerate adoption of bioenergy technology in the forest industry.
- The Province will work with the bioenergy industry and others to develop new fine particulate standards for industrial boilers to improve air quality.

BIOFLEET is an initiative to expand the development and use of biodiesel in Western Canada. This project will continue to build market confidence in biodiesel to increase the purchase and use of clean, renewable fuel and will also reduce greenhouse gas emissions generated by vehicle fleets. British Columbia will consume more than 500 million litres of biofuel annually by 2010.

3 | STRENGTHEN B.C.'S BIOENERGY NETWORK

BC BIOENERGY NETWORK

To support B.C.'s clean energy goals, capture value from beetle damaged timber and help rural agriculture and forest communities diversify and remain competitive, Government will establish funding for a $25 million Bioenergy Network. It will set the course to reduce greenhouse gas emissions, while increasing home-grown renewable energy production and strengthening the forest and agriculture industries.

This commitment will build on the existing foundation of bioenergy production sites, research centres and technology development projects, leading the way to greater investment in innovation and affirming B.C.'s role as a world leader and global partner for sustainable bioenergy solutions.

British Columbia has a strong bioenergy and biorefining network of academic and industry talent, as well as a number of active projects.

Building on the Existing Bioenergy and Biorefining Network

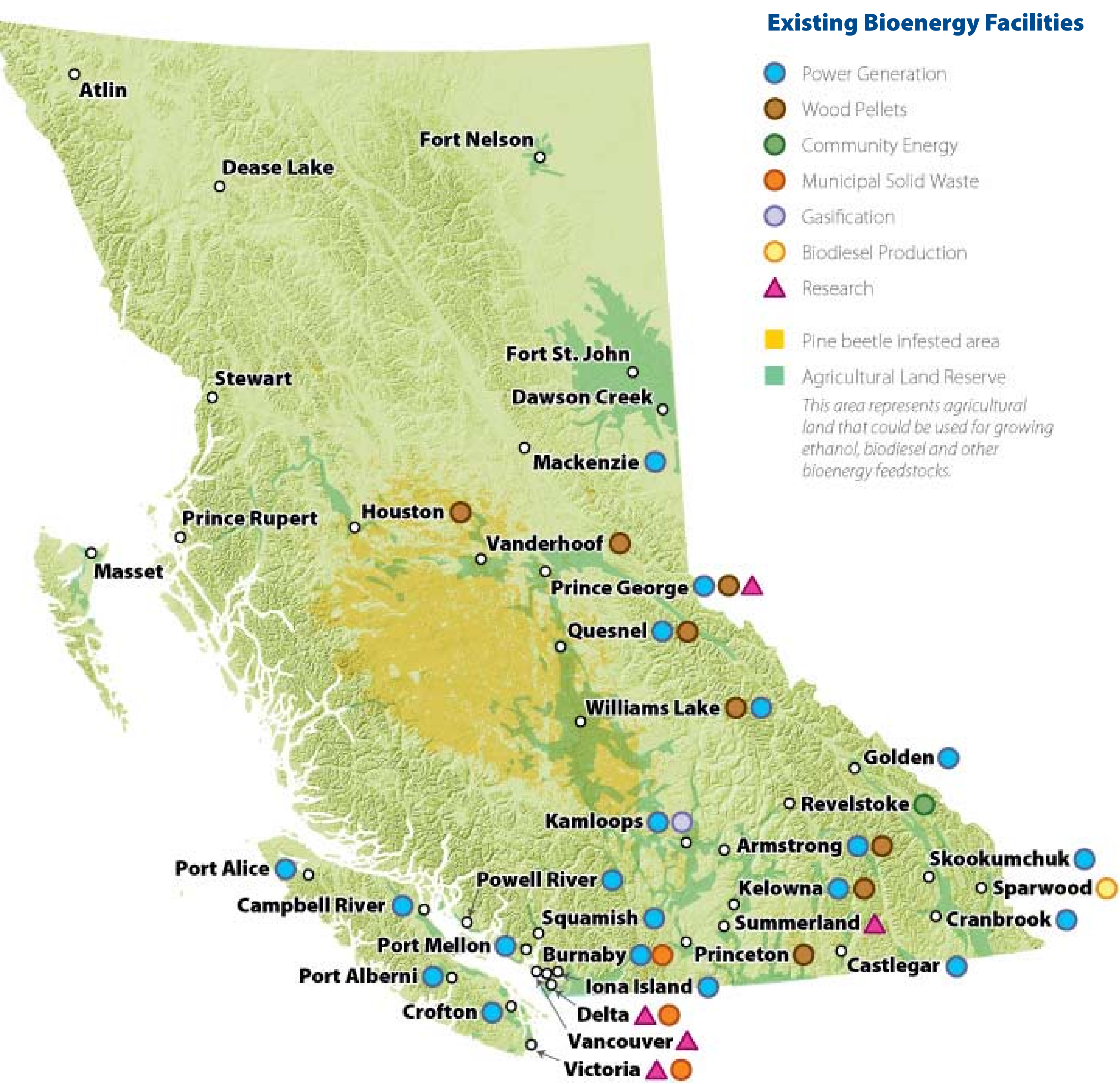
The purpose of the Network is to achieve greenhouse gas emission reductions, improve air quality and capitalize on B.C.'s bioenergy potential through the development of projects which could include:

- New bioenergy technology and production capacity to better utilize beetle damaged timber and other woodwaste in sawmills and pulp mills.
- Agricultural biogas production from animal and food processing wastes.
- Next-generation biofuels such as ethanol from woodwaste and biodiesel from algae.
- Projects to convert municipal waste and landfill gas to electricity and other fuels.

The Network strengthens the development of world-class bioenergy research and technology expertise in British Columbia. This will include the creation of at least one academic leadership chair in bioenergy.

British Columbia's current bioenergy network already includes:

- Over 800 megawatts of biomass electricity capacity is installed in British Columbia, primarily within the forest sector – enough for 640,000 households.
- The British Columbia wood pellet industry enjoys a 16 per cent share of the growing European Union market for bioenergy feedstock. In 2007, British Columbia produced over 900,000 tonnes of wood pellets, of which 90 per cent was exported for thermal power production overseas.
- British Columbia's pulp and paper mills meet over 33 per cent of their electricity needs through cogeneration of electricity and steam on site.


Existing Bioenergy Facilities
Power Generation
Wood Pellets
Community Energy
Municipal Solid Waste
Gasification
Biodiesel Production
Research
Pine beetle infested area
Agricultural Land Reserve
This area represents agricultural land that could be used for growing ethanol, biodiesel and other bioenergy feedstocks.
Atlin
Fort Nelson
Dease Lake
Fort St. John
Stewart
Dawson Creek
Mackenzie
Houston
Prince Rupert
Vanderhoof
Masset
Prince George
Quesnel
Williams Lake
Golden
Revelstoke
Kamloops
Armstrong
Skookumchuk
Port Alice
Powell River
Kelowna
Sparwood
Campbell River
Squamish
Summerland
Cranbrook
Port Mellon
Burnaby
Princeton
Castlegar
Port Alberni
Iona Island
Crofton
Delta
Vancouver
Victoria

Building Bioenergy Capacity

When it comes to using renewable fuels, British Columbians are among the most receptive consumers, and the demand for biodiesel and ethanol is growing. Municipalities including Vancouver, Richmond, Whistler, Delta, Burnaby and North Vancouver are using biodiesel in their fleet vehicles, and so are BC Transit and other commercial fleets. There is significant potential to expand the production and use of biofuels in the Peace River Region and other areas of the province. Community energy projects increase energy self-sufficiency, address waste management issues, diversify local industries and create new jobs. Projects underway include:

- Highlighting biomass and bioproduct development potential in Quesnel through an inventory of available wood fibre.
- A biomass energy system to heat schools in Nakusp.
- An engineering assessment and business model for a biomass heat-and-power community energy system in Port Hardy.
- A biomass gasification community energy project at Dockside Green in Victoria.

British Columbia is expanding its bioenergy capacity through government funding for bioenergy programs, including:

- Up to $10 million in funding over three years for biodiesel production.
- A biodiesel production feasibility study to encourage the development of oilseed crushing and biodiesel facilities in the Peace Region.
- A feasibility study conducted by the BC BioProducts Association on building an anaerobic digestion and gas processing facility in the Fraser Valley.
- The Anaerobic Digester Calculator Project, an electronic tool to assess the environmental benefit and economic viability of constructing anaerobic digestion facilities in specific locations.

Ethanol BC, a program to support value-added uses for wood residue, has funded:

- Research and development of softwood residue-to-ethanol technology by Lignol Innovations.
- Advances in wood gasification technology by Nexterra.
- Fuel pellet design, engineering and emission performance assessments testing wood, agricultural fibre and other feedstocks.

The Province is promoting a Product Commercialization Roadmap that will enhance the export success of British Columbia's bioproducts by guiding companies through business planning, financial analysis and processes for product and market development.

NEXT STEPS

The Province will establish the Bioenergy Network to:

- Support wood gasification research, development and commercialization in collaboration with the University of Northern British Columbia, University of British Columbia, Forest Products Innovation, the National Research Council, the forestry and energy sectors, industry and other partners.
- Advance biorefining for multiple, value-added product streams, such as biochemicals, in conjunction with bioenergy production in new facilities and/or at existing industrial operations by working with the BC Bioproducts Association, First Nations, agricultural and forest sectors.
- Encourage the development of pilot and demonstration projects with industries and communities in key biomass resource areas.
- Support research into socially and environmentally responsible dedicated energy crop production and enhance enzymatic and other biotechnology solutions for biomass-to-energy conversion.
- Advance the development of biofuels, such as cellulosic ethanol and renewable diesel from algae and other resources, through the Green Energy and Environmentally Friendly Chemical Technologies Project and other initiatives.

WITHIN OUR POWER

British Columbia has an abundance of underutilized wood in the form of sawmill residues and logging debris, and a growing supply of timber killed by the mountain pine beetle.

British Columbia currently leads the nation in wood energy production and consumption. However, it is estimated that about 1.2 million bone-dry tonnes of mill residues per year – an amount that could produce approximately 1,900 gigawatt hours of electricity – are incinerated in beehive burners in the province with no energy recovery and impacts on air quality. These resources and wood residues in other regions present an opportunity for bioenergy in British Columbia.

WOOD PELLETS are produced from wood residue collected from sawmills and wood product manufacturers. Heat and pressure are used to turn wood residue into pellets without chemical additives, binders or glue.

CROSS-GOVERNMENT COLLABORATION

The Province will work with federal agencies such as Sustainable Development Technology Canada, Natural Resources Canada, and the Western Diversification Office to:

- Promote bioenergy research and project development, support the efficient use of biomass, address current waste challenges and diversify community economies.
- Streamline and coordinate the development of bioenergy policies and programs to advance the Province's goals for energy, the economy and the environment.

B.C. is viewed around the world as a bioenergy hot spot, and its increasing profile in the global economy highlights the importance of strong relationships with other jurisdictions with shared interests in bioenergy development.

Nationally and internationally, many view British Columbia as the hub of a growing bioenergy and biorefining network. The Western Climate Initiative allows B.C. to foster economic opportunities through the development of new technologies and innovation. B.C. and western states have engaged in electricity trading for the past 30 years, and the Government has signed a joint statement with Sweden that strengthens a partnership of information exchange and best practices for the development and use of bioenergy and biorefining technologies. The BC Bioenergy Strategy affirms B.C.'s commitment in an agreement with Manitoba to reduce greenhouse gas emissions by broadening renewable energy portfolios to include biomass power.

The expertise gained through the BC Bioenergy Strategy offers other jurisdictions the potential to benefit, while creating new economic opportunities for British Columbians. With our plentiful biomass resources, industry and academic leadership, and the Government commitment to bioenergy, British Columbia will continue to:

- Develop, deploy and export British Columbia's clean and alternative energy technologies.
- Maximize bioenergy market opportunities.
- Advance bioenergy research, collaborate in project development and build upon shared interests with other jurisdictions in Canada and around the world.

NEXT STEPS

- The Province will advance joint interests and share information on best practices in bioenergy research and development with the Western Climate Initiative and the Pacific NorthWest Economic Region.
- Under the British Columbia/Alberta Memorandum of Understanding on Energy Research, Technology Development and Innovation, the Government will develop a joint framework for bioenergy research, technology demonstration and deployment.
- The Province will create First Nations bioenergy opportunities and invite representatives to speak about biomass community energy systems.
- The Province will release an information guide on pursuing biomass energy opportunities and technologies in British Columbia for First Nations, small communities, local government and industry.

CONCLUSION

With our strengths in bioenergy, British Columbia will pursue our alternative energy advantage. Bioenergy is critical in meeting that objective. The know-how, researchers and partner communities here today are committed to making this happen. The enhanced BC Bioenergy Network, funding to advance biodiesel production and the two-part Bioenergy Call for Power, will take B.C. the next step in realizing our full natural resource potential.

The BC Bioenergy Strategy will benefit communities by helping make cleaner, greener energy available for use in our homes and vehicles. It will benefit our economy by tapping into the potential of B.C.'s biomass resources, unleashing the energy of materials that previously went to waste and promoting the development of new industries and markets. In turn, it will benefit our environment by helping meet our growing energy demands with clean, renewable and environmentally responsible energy resources.

BIOENERGY TECHNOLOGY DEVELOPMENT TIMELINE

NOW

TECHNOLOGIES IN USE IN B.C.

WOOD TO ELECTRICITY BY COMBUSTION AND STEAM TURBINES

Technology available–economics drive the decision

WOOD TO SOLID FUEL PELLETS

Technology available–economics drive the decision

WOOD TO SYNGAS FOR WOOD DRIERS

Recently implemented in B.C.–driven by high natural gas prices

WOOD TO SYNGAS FOR PULP MILL LIME KILNS

Further research and development required to maintain clean syngas stream

2010 - 2015

TECHNOLOGIES EXPECTED TO BE IN USE

BIOMASS TO CLEAN SYNGAS TO POWER INTERNAL COMBUSTION ENGINE FOR UP TO 10MW ELECTRICITY GENERATION

To be piloted–high probability of success

BIOMASS TO HIGH GRADE SYNGAS FOR LIQUID FUEL PRODUCTION

Needs research and development, large-scale pilots and further research and development on catalysts to adapt current technology for coal conversion

WOOD TO CLEAN SYNGAS TO POWER TURBINE FOR ELECTRICITY GENERATION

Needs pilot trials and research and development

** SYNGAS is synthetic gas produced through the thermal gasification of biomass.*

TECHNOLOGIES EXPECTED TO BE IN USE

2015 - 2020

CELLULOSE TO ETHANOL

Needs large-scale pilots and further research and development on enzymes

AGRICULTURAL WASTE/ MANURE TO POWER

Technology available– economics drive the decision

ENERGY CROPS LIKE GRAIN AND OILSEEDS TO RENEWABLE FUELS

Technology available– economics drive the decision

ANAEROBIC DIGESTION AND ALGAE FARMING FOR BIO-OIL

Needs pilot scale trials and research and development

BIOREFINING: BIOMASS TO ENERGY, BIOCHEMICALS AND OTHER PRODUCTS

Needs extensive research and development

Four key drivers spurred the development of the BC Bioenergy Strategy:

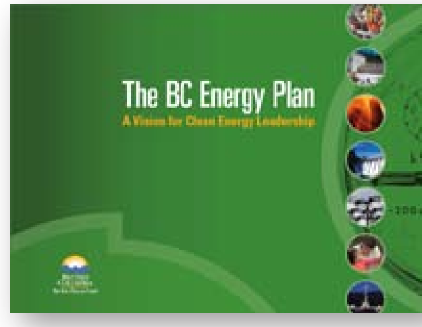
1 **Environment** – bioenergy can lower greenhouse gas and other air emissions and encourage the shutdown of beehive burners, organic garbage conversion, methane capture from landfills and better agricultural waste management.

2 **Mountain Pine Beetle Infestation** – bioenergy can help capture value from a deteriorating resource and help the forest sector, as well as impacted communities, remain competitive.

3 **Electricity Self-sufficiency** – bioenergy can help B.C. meet its future energy demands and become energy self-sufficient with made-in-B.C. energy resources from the forest and agricultural sectors.

4 **Long-term Competitiveness** – bioenergy can create new bioeconomic opportunities for forestry, agriculture, municipalities and First Nation communities and establish British Columbia as a global supplier of bioenergy resources, technologies and services.

The BC Bioenergy Strategy supports these BC Energy Plan Policy Actions:



- Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
- Establish a standing offer for clean electricity projects up to 10 megawatts.
- All new electricity generation projects will have zero net greenhouse gas emissions.
- Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
- Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
- Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
- Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
- Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.
- Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
- Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
- Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
- Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
- Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
- Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
- Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

For more information on the BC Bioenergy Strategy contact:

Ministry of Energy, Mines and Petroleum Resources
1810 Blanshard Street
PO Box 9318 Stn Prov Govt
Victoria, BC V8W 9N3
Tel: 250.952.0156

www.energyplan.gov.bc.ca/bioenergy

BRITISH COLUMBIA
The Best Place on Earth

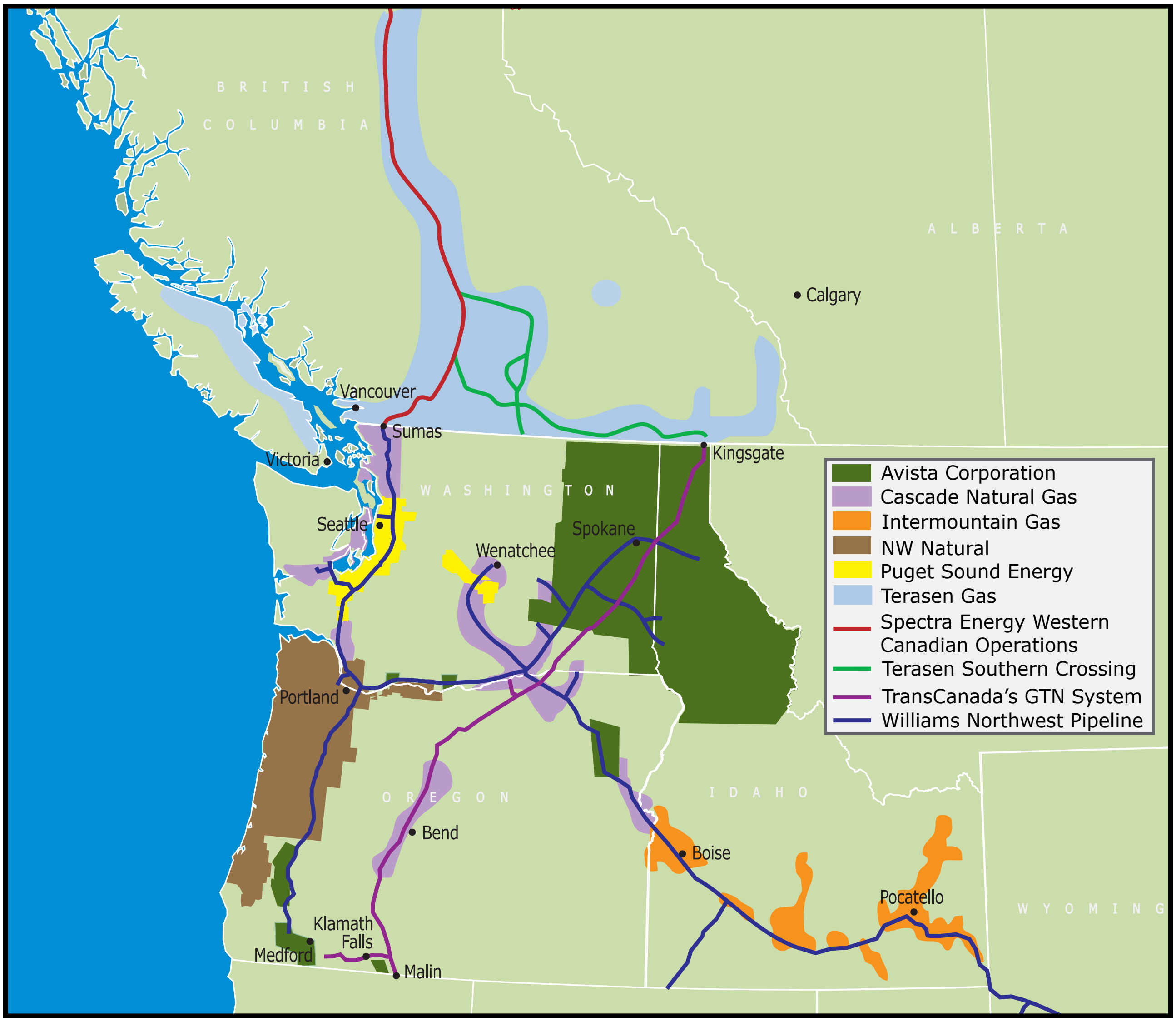
Ministry of
Energy, Mines and
Petroleum Resources

2010 Gas Outlook

NATURAL GAS DEMAND, SUPPLY AND SERVICE CAPACITY IN THE PACIFIC NORTHWEST

PROJECTIONS THROUGH OCTOBER 2019

NWGA SERVICE AREA MAP



NWGA MEMBERS

Avista	(800) 227-9187	www.avistautilities.com
Cascade Natural Gas Corporation	(206) 624-3900	www.cngc.com
Intermountain Gas Company	(208) 377-6000	www.intgas.com
NW Natural	(503) 226-4211	www.nwnatural.com
Puget Sound Energy	(425) 454-6363	www.pse.com
Spectra Energy Transmission	(604) 691-5500	www.spectraenergy.com
Terasen Gas	(800) 773-7001	www.terasengas.com
TransCanada GTN System	(503) 833-4000	www.gastransmissionnw.com
Williams' Northwest Pipeline	(801) 583-8800	www.williams.com

ABOUT THE NORTHWEST GAS ASSOCIATION

The NWGA is a trade organization of the Pacific Northwest natural gas industry. It seeks to meaningfully shape policies to help increase the diversity, abundance and dependability of natural gas supply and infrastructure available to serve the Pacific Northwest. Its members include six natural gas utilities serving communities throughout Idaho, Oregon, Washington and British Columbia, and three transmission pipelines that transport natural gas from supply basins into and through the region.

Avista Utilities (www.avistautilities.com) – Serves over 310,000 natural gas customers in three Western states including northern Idaho, parts of southwestern and northeastern Oregon and eastern Washington.

Cascade Natural Gas Corporation (www.cngc.com) – Serves approximately 251,000 residential, commercial and industrial natural gas customers in 93 communities in Oregon and Washington.

Intermountain Gas Company (www.intgas.com) – Serves over 300,000 residential, commercial and industrial customers in 23 counties and 75 cities generally along the Snake River plain in southern Idaho.

NW Natural (www.nwnatural.com) – Serves 657,000 customers in Oregon and southwest Washington, including the Portland-Vancouver metropolitan area, the Willamette Valley, the northern Oregon coast and portions of the Columbia River Gorge.

Puget Sound Energy (www.pse.com) – The Pacific Northwest's largest energy utility provides electric and/or natural gas service to more than 1.2 million customers primarily in Washington State's Puget Sound region.

Spectra Energy Transmission (www.spectraenergy.com) – Delivers gas to markets in British Columbia (BC) and the Pacific Northwest via a 1,600-mile pipeline transmission system stretching from Fort Nelson in northeast BC and Gordondale at the BC/Alberta border to the BC/U.S. border at Huntingdon/Sumas. Spectra's system is capable of transporting approximately 1.7 billion cubic feet (Bcf) of Canadian gas to key markets daily.

Terasen Gas (www.terasengas.com) – The largest distributor of natural gas in the Pacific Northwest and the third largest gas utility in Canada, serving more than 900,000 customers in 125 communities across British Columbia.

TransCanada Gas Transmission Northwest (www.gastransmissionnw.com) – Serves markets in California and Nevada, delivers gas in the Pacific Northwest directly to customers off its mainline system and to local distribution companies in Idaho, Oregon and Washington. The GTN system is capable of transporting approximately 2.9 Bcf of Canadian and domestic gas per day.

Williams Northwest Pipeline (www.williams.com) – Serves customers in seven western states with a 4,000 mile bi-directional system that extends from the San Juan Basin in western Colorado/New Mexico state border to the U.S./Canadian border at Sumas. The system is capable of delivering up to 3.4 Bcf of peak-day gas from key supply points such as the Rockies, San Juan Basin and Western Canada Sedimentary Basin. Northwest also has working natural gas storage capacity of approximately 12.4 Bcf.

TO OUR READERS:

Throughout this report we have used terminology specific to the natural gas industry. This includes the most common units of energy used to describe natural gas a measure of volume, and therms a measure of energy (or heat). When discussing the specifics of natural gas demand, supply or capacity, we have tried to be consistent about using the same unit of energy throughout a related section.

Here are some basic definitions for the various units of energy discussed to help our readers make comparisons should the need arise. While the energy content of natural gas varies according to its specific composition, we have generally used the value of 1,030 British thermal units (Btus) per cubic foot of natural gas when making conversions.

Btu	British thermal unit – a measure of energy content (non-metric).
1 Btu	The energy required to increase the temperature of one pound of water one degree Fahrenheit under standard (defined) conditions.
MMBtu	One million Btus – the typical unit by which natural gas is bought and sold (e.g. "the spot price of natural gas is $7.00 per MMBtu").
J	Joule – a measure of energy content (metric).
GJ	One trillion joules; .9478 MMBtu
1 J	The energy required to lift a small apple (102 grams) one meter against Earth's gravity.
cf	Cubic foot – a measurement typically used to describe natural gas volumes, as in reserves, deliveries, storage levels, etc.
1 cf	Approximately 1,030 Btus; the energy content of natural gas varies by its source. This document uses 1,030 Btus/cf as a general rule.
Mcf	1,000 cubic feet. Equivalent to 1.03 MMBtu.
MMcf	1 million cubic feet. Equivalent to 1.03 MDth.
Bcf	1 billion cubic feet. Equivalent to 1.03 MMDth.
Bcf/d	1 billon cubic feet per day
Tcf	1 trillion cubic feet.
Therm	A unit of heat equal to 100,000 Btus.
Dth	Decatherm; Equivalent to 10 therms, 1 million Btus or 0.975 Mcf.
MDth	1,000 Decatherms. Equivalent to 0.975 MMcf.
MMDth	1 million Decatherms. Equivalent to 0.975 Bcf.
W	Watt – a measure of electrical energy.
kw	Kilowatt or 1,000 watts.
kWh	Kilowatt-hour, a measurement of electrical energy used over time. (Ten 100w light bulbs burning for one hour would use 1 kWh.)
1 kWh	3,413 Btus.
hp	Horsepower – a measure of mechanical energy. One horsepower equals 550 foot-pounds per second.
1 hp	746 watts.
hp-hr	Horsepower-hour.
1hp-hr	2,545 Btus.

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EXECUTIVE SUMMARY

Compiled annually by the Northwest Gas Association (NWGA) and its members, this report provides a consensus industry perspective of the Pacific Northwest's current and projected natural gas demand, supply, delivery capability and prices. For purposes of this report, the Pacific Northwest is defined as Oregon, Washington, Idaho and British Columbia (BC). This forecast covers the period beginning Nov. 1, 2009, and ending Oct. 31, 2019.

Information and data for the report were provided by NWGA member companies and drawn from various public and internal planning documents (e.g., integrated resource plans, least-cost plans, etc.), then compiled and analyzed to arrive at a composite regional perspective.

Regional, national and continental statistics were obtained from a variety of sources, including the Energy Information Administration (EIA), Northwest Power and Conservation Council (NWPCC), National Energy Board (NEB) – Canada, Statistics Canada (StatCan) and others as cited.

By sharing information about the dynamics of the regional natural gas industry, the Association intends to:

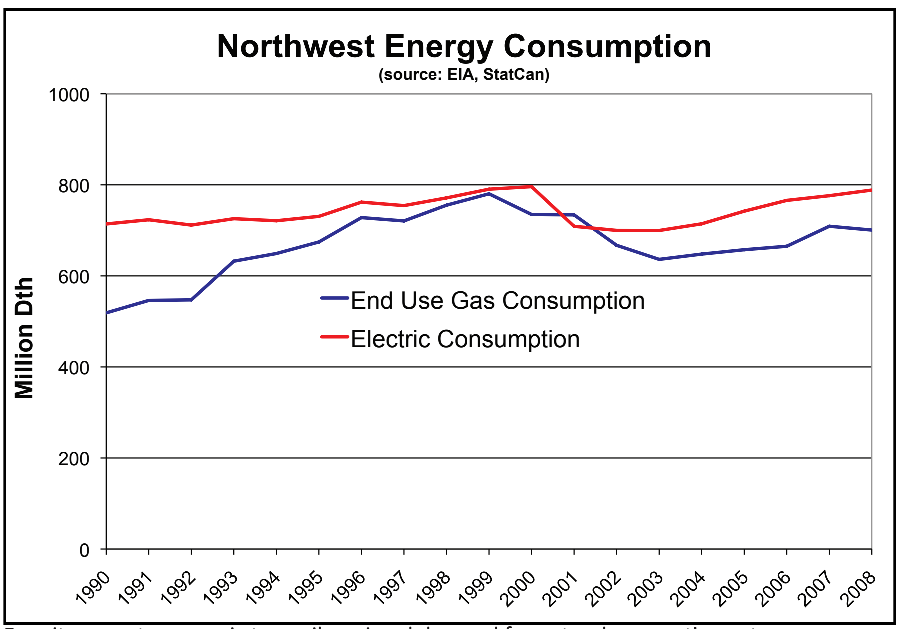
- Establish shared priorities for addressing future challenges; particularly, ensuring a reliable supply of natural gas to serve regional demand.
- Promote public policies and industry and consumer actions that will ensure the wise and most cost-effective use of natural gas.
- Build a broad-based awareness of the role natural gas will play in reducing greenhouse gas (GHG) emissions and helping the region achieve its environmental goals.

Understanding the natural gas market and how best to use this valuable resource is particularly important today as the region joins energy users across the globe to address climate change. As the cleanest burning fossil fuel, natural gas is already playing a central role in emerging policies and energy industry initiatives to protect our environment.

THE ROLE OF NATURAL GAS IN THE NORTHWEST

Natural gas is an integral part of the Pacific Northwest energy portfolio:

- Natural gas burned directly for residential space and water heat, and for commercial and industrial processes (i.e., "end use") accounts for almost as much energy as the region consumes via electricity (see chart).
- According to the NWPCC, natural gas fuels 24 percent of the region's power generation capability – a larger share than any resource except hydropower, which makes up 48 percent.
- The number of natural gas customers in the region grew by almost 18 percent between 2000 and 2008, despite a regional economic downturn and volatile natural gas prices.



Despite recent economic turmoil, regional demand for natural gas continues to grow.

HOW RECENT HISTORY HAS SHAPED TODAY'S MARKET

The last decade has been punctuated by events that have significantly changed the Pacific Northwest energy market. Skyrocketing energy costs as a result of the Western energy crisis early this decade had far-reaching and, in some cases, permanent impacts on the region's economy, including the almost complete loss of an entire industry (aluminum) and thousands of good paying jobs. More recently, the national credit crisis, collapse of the housing market and high unemployment have plagued North America and the Northwest, again dampening energy demand.

The more interesting story may be what is happening on the supply side of the equation. Improved technologies have made the recovery of vast reserves of "unconventional" natural gas throughout North America feasible, especially those found in shale formations. In June of 2009, the Potential Gas Committee (PGC) increased its estimate of U.S. natural gas reserves by more than 40 percent over 2008: the largest single year increase in reserves since the PGC began issuing its annual report. That's the equivalent of more than 100 years of supply at today's consumption rates.

The rising tide of new supplies coupled with dampened demand gave consumers a welcome respite from the high natural gas prices they have experienced in recent years. The fall of 2009 brought some of the lowest gas prices in years.

As we move into 2010, emerging energy policies aimed at reducing carbon and other GHG emissions, encouraging conservation and promoting the wise and efficient use of existing energy resources will significantly shape the regional energy market. State, provincial, regional and national plans already in force or under consideration prioritize conservation and renewable energy sources. But policymakers recognize that these alone will not cover our growing energy needs and a truly comprehensive plan must take a multi-pronged approach. It is apparent that any plan to build a foundation for our energy future must include a significant role for abundant, clean and efficient natural gas.

This report looks at how this changing energy paradigm affects future natural gas demand, supply, infrastructure and prices in our region.

SUMMARY OF KEY CONCLUSIONS

The Pacific Northwest has a strong environmental ethic. Policymakers in some jurisdictions have set decidedly ambitious goals to reduce GHG emissions and promote energy production from renewable resources. Achieving these objectives will require collaboration and a concerted effort. The Pacific Northwest natural gas industry is committed to helping the region meet its environmental mandates by encouraging the most efficient use of natural gas, acquiring necessary supply, and building the infrastructure needed to sustain a balanced market and stabilize prices. Policymakers will have a significant impact on the demand for, and availability and price of, natural gas in the future through the energy laws they implement. Consumers too will contribute by the actions they take at home and at work. We offer this report to help inform and guide the region's efforts.

BLUE FOUNDATION FOR A GREEN ENERGY FUTURE

As the cleanest burning fossil fuel with abundant supplies across the globe, natural gas will help the Pacific Northwest achieve its environmental goals.

The following summarizes key conclusions drawn from the data and discussion contained in this report:

DEMAND

- Natural gas consumption (as measured by energy content, or decatherms - Dth) in the Pacific Northwest is expected to grow an average of 1 percent per year, with a cumulative projected growth of 8.5 percent, through 2019. Most of this increase will be driven by demand for gas-fired electrical generation and continued growth in residential demand.

Natural gas demand will grow in the region as new energy policies encourage its use, both for gas-fired electrical generation and directly heating homes, buildings and water.

- Peak day demand remains about the same as that projected in the 2008 Outlook. Annual loads start from a lower base in 2009-10 (2009-10 projection of 800 MMDth vs. 900 MMDth actual demand in 2008) due primarily to lower industrial loads, fewer customers and lower consumption per customer caused by the recession.

- Energy policies are encouraging greater use of clean-burning natural gas to help reduce GHG emissions and complement development of renewable energy resources.

- Energy efficiency and conservation, intrinsic to the region's energy values, are the cornerstones of emerging regional and national energy plans. This further supports using natural gas for its most efficient purposes – directly heating homes, buildings and water.

SUPPLY

- Natural gas supplies are plentiful across North America and the world and include a variety of sources. Improved production technologies and market economics have recently spurred unprecedented recoverable natural gas discoveries across the continent.

- The Pacific Northwest market continues to benefit from its proximity to the Western Canadian Sedimentary Basin (WCSB) and the U.S. Rockies, two large and prolific gas-producing regions.

- Competition for the supplies upon which the Northwest depends is intensifying as producers seek more lucrative markets and those markets seek access to lower-priced supplies – and pipelines are built to connect the two.

Natural gas supplies are plentiful, but the Northwest is increasingly competing for them with other markets.

CAPACITY

- The region's growing dependence on natural gas to help meet its environmental goals will drive the need for additional infrastructure to access more gas from our traditional sources and from new sources.

Eventually, the region will require new delivery infrastructure to serve growing demand.

- During extreme weather events (peak days), the existing system of natural gas pipelines and storage facilities serving the Northwest is efficiently utilized with little redundancy.

- Infrastructure developers have responded to the region's emerging need by proposing several projects to deliver more supplies to the region from a diversity of sources, which can be built as market conditions dictate.

PRICES

- Natural gas prices reflect the balance between demand and supply, which shifted significantly in the past year. High natural gas daily spot prices in North America during the summer of 2008 (~$13/Dth) contrast sharply with the low daily spot prices experienced during the summer and fall of 2009 (at one point, less than $2/Dth).

- Policymakers can and will influence natural gas prices depending on whether and how they address critical issues affecting the supply/demand balance, including access to new sources of supply, infrastructure development and efficient use of natural gas.

High natural gas prices dropped to seven-year lows in the past year, reflecting the fluctuating balance between demand and supply.

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REGIONAL NATURAL GAS DEMAND

KEY CONCLUSIONS

1. Natural gas consumption (as measured by energy content, or decatherms - Dth) in the Pacific Northwest is expected to grow an average of 1 percent per year, with a cumulative projected growth of 8.5 percent through 2019. Much of this increase will be driven by demand for gas-fired power generation and continued growth in residential demand.

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3. Energy policies are encouraging greater use of clean-burning natural gas to reduce greenhouse gas (GHG) emissions and complement development of renewable energy resources.

4. Energy efficiency and conservation, intrinsic to the region's energy values, are the cornerstones of emerging regional and national energy plans. This further supports using natural gas for its more efficient purposes – directly heating homes, buildings and water.

A CLOSER LOOK

RECENT DEMAND

Before the global economic downturn in 2008, natural gas demand in the Pacific Northwest was growing steadily. Although the energy crisis of 2000-01 caused a temporary hiccup in demand for most consumer groups (the effect on industrial consumption was more significant), aggregate demand for natural gas subsequently grew by 14 percent between 2003 and 2008 (almost 3 percent annually).[1]

The following is a look at natural gas consumption patterns during this period for different customer groups:

Residential and commercial consumers used 15 percent more natural gas in 2008 than in 2003, growth of more than 3 percent annually. Sometimes referred to as the core market, gas demand in this sector varies widely with the weather. In our region, cold weather is the primary driver of core market demand. The price of natural gas – which is passed through directly to consumers without markup by the local gas company – can also affect core demand. Efficient and affordable appliances, good building codes and improved weatherization of existing homes have all affected core demand in recent years. According to the American Gas Association, residential consumers use 32 percent less gas today on a per-customer basis than they did in 1980.

> To manage demand growth so it does not outpace supply, policymakers and the industry need to aggressively pursue additional conservation and wise-use initiatives.

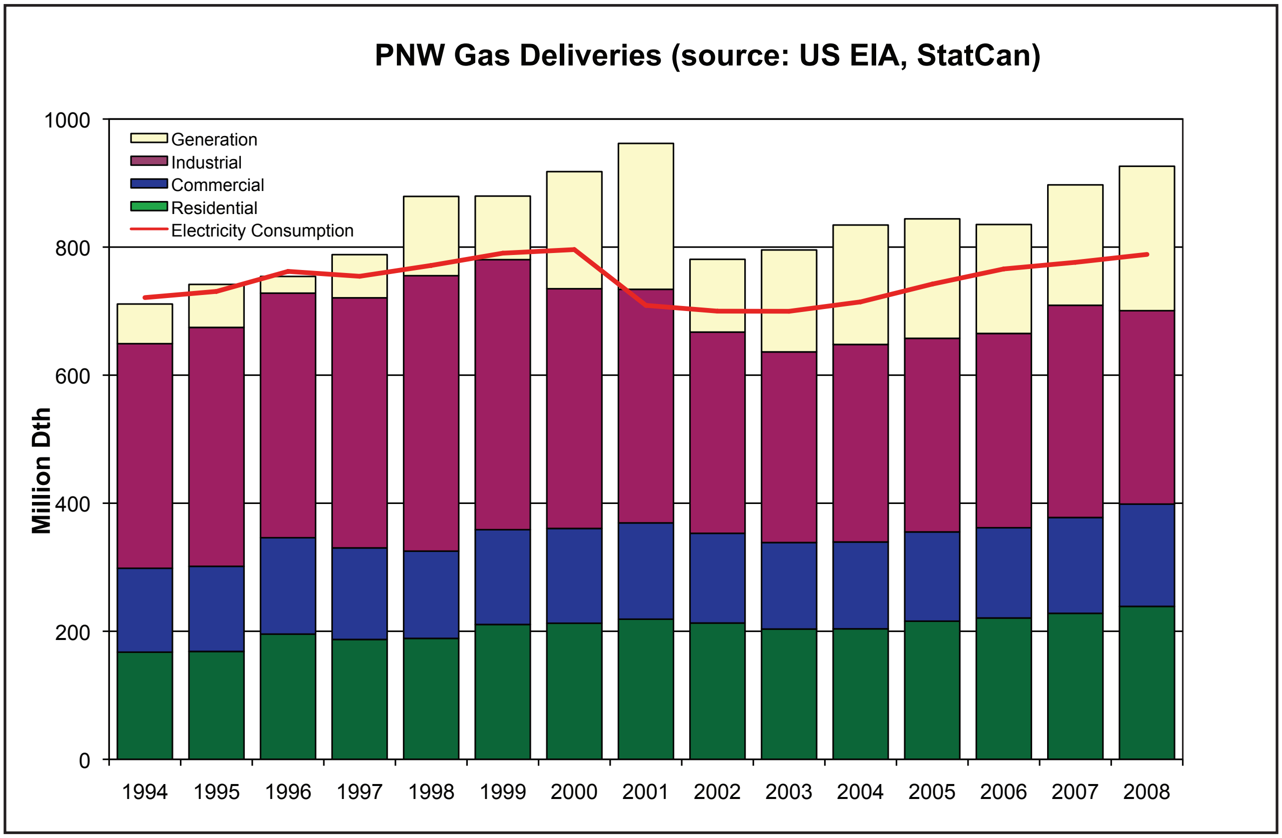
Industrial consumption of natural gas grew about 1.5 percent from 2003 to 2008. Weather has less effect on the industrial sector as most manufacturing processes run year-around regardless of weather conditions. The industrial sector is highly price-sensitive however, since energy costs are usually a large portion of the overall cost of production. Industrial consumers were especially hard hit during the earlier energy crisis, causing some companies to close plants and merge operations. These changes, along with aggressive implementation of energy conservation measures, have permanently changed the region's industrial base. Industrial consumption of natural gas in 2008 was 42 percent lower than at its apex in 1998.

Power generation demand has been volatile, reflecting the many variables that can affect it. These include weather, the availability of hydropower and the cost of natural gas and oil. Public policies that have restricted the development of other resources (e.g. nuclear, hydropower, coal) and promoted development of renewable resources also affect gas-fired generation demand.

[1] US Energy Information Administration (EIA), *Annual Natural Gas Consumption By End Use*; Statistics Canada, Tables 129-0003 and 131-0001.

Currently, natural gas is the primary fuel for 24 percent of the region's power generating capability. The region's gas-fired fleet is capable of delivering 9,100 average megawatts (aMW) of power. [2] Gas demand for generation peaked in 2001 due to the energy crisis, dropped by half the following year and then grew more than 12 percent annually through 2008 to once again approach 2001 levels.

FIGURE 1. PACIFIC NORTHWEST NATURAL GAS DEMAND - 1994-2008



SOURCE: US EIA, STATCAN COMPILED BY NWGA

PROJECTED DEMAND

Natural gas demand in the Pacific Northwest is expected to grow 1 percent annually, for a total of 8.5 percent through 2019, given normal weather conditions and expected economic and population growth (called "base case;" see Table 1). Demand growth by residential/commercial customers eclipsed that of gas-fired power generation facilities in past years, but changing energy policies have spurred an increase in anticipated generation demand.

TABLE 1. PROJECTED REGIONAL DEMAND GROWTH

09 OUTLOOK UPDATE	Low Demand Growth		Expected (Base) Demand Growth		High Demand Growth	
	Average Annual %	Cumulative	Average Annual %	Cumulative	Average Annual %	Cumulative
TOTAL	**0.3%**	**2.8%**	**1.0%**	**8.5%**	**1.3%**	**11.0%**
Residential	0.5%	4.5%	1.1%	9.4%	1.8%	14.6%
Commercial	0.2%	2.1%	0.8%	6.9%	1.4%	11.8%
Industrial	0.6%	4.8%	0.7%	6.2%	0.7%	6.2%
Generation	-0.1%	-0.5%	1.3%	10.8%	1.4%	11.4%

SOURCE: NWGA

Base case projections reflect the current recessionary economy and an expected slow recovery, which some economists believe has begun. The low growth case assumes slower than expected economic growth while high growth considers a more rapid economic expansion. Projected gas prices also figure into the respective forecasts.

[2] NWPCC, draft *Sixth Northwest Power Plan*, September 2009.

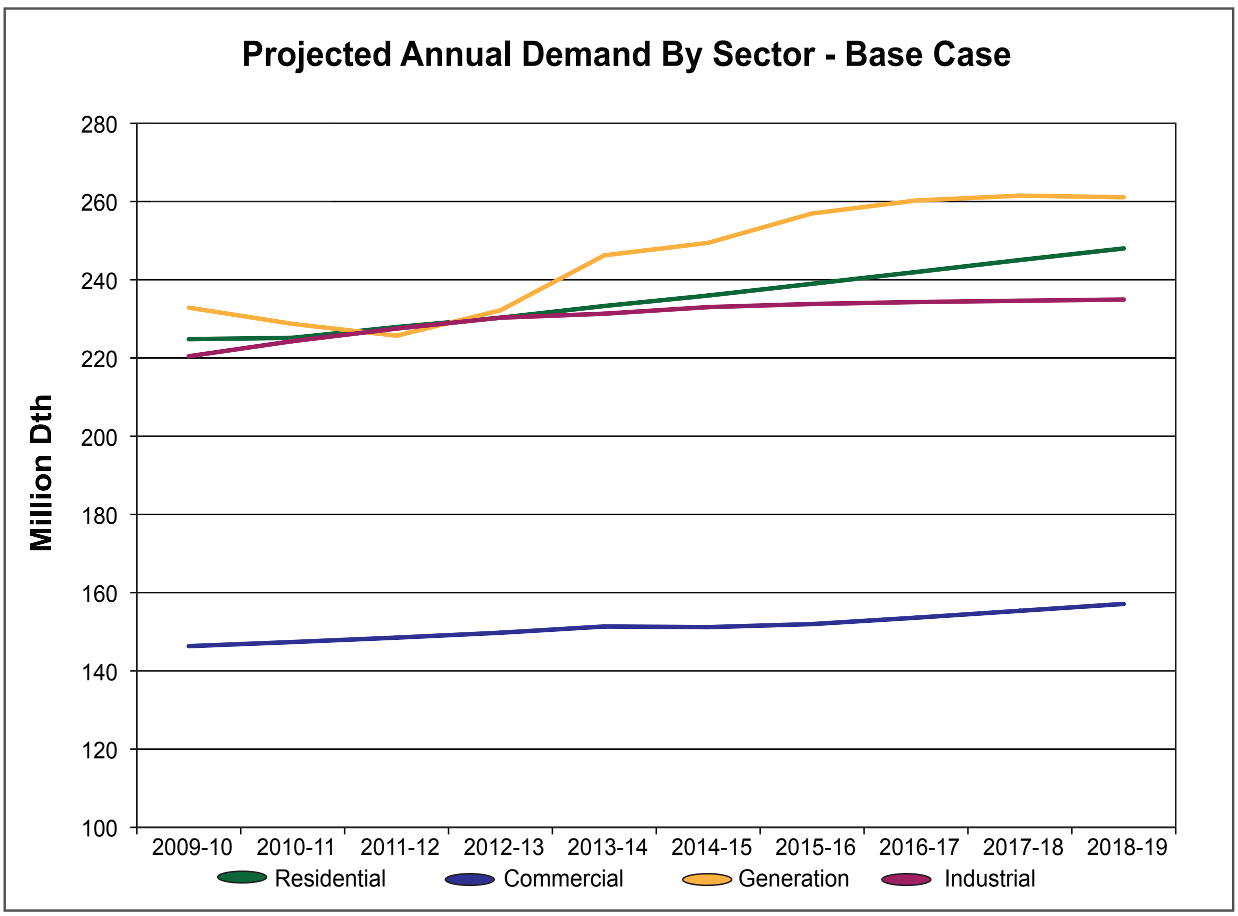
In the base case, near-term growth will be less than the average annual 1 percent projection for some customer groups – e.g., residential growth will be slower initially as new home construction slowly rebounds – but is expected to accelerate in later years. Since natural gas is a good value for home heating, it remains the fuel of choice for space and water heat in most new single-family home construction and many older electric furnaces and water heaters are being replaced with natural gas units.

Commercial and industrial demand, dampened by the recent economic downturn, is expected to recover – with industrial demand projected to grow slightly faster than in recent years. Power generation demand is anticipated to grow 10.8 percent over the next decade (base case), because of growing requirements for gas-fired generation. As mentioned previously, this demand can be volatile because of weather, stream flows in the Northwest hydro system, availability of new renewable electricity sources, fuel prices and a host of other factors.

Infrastructure developments are typically driven by peak day loads – the highest volumes a system may be expected to carry – which have held steady even as annual loads dropped due to the recession.

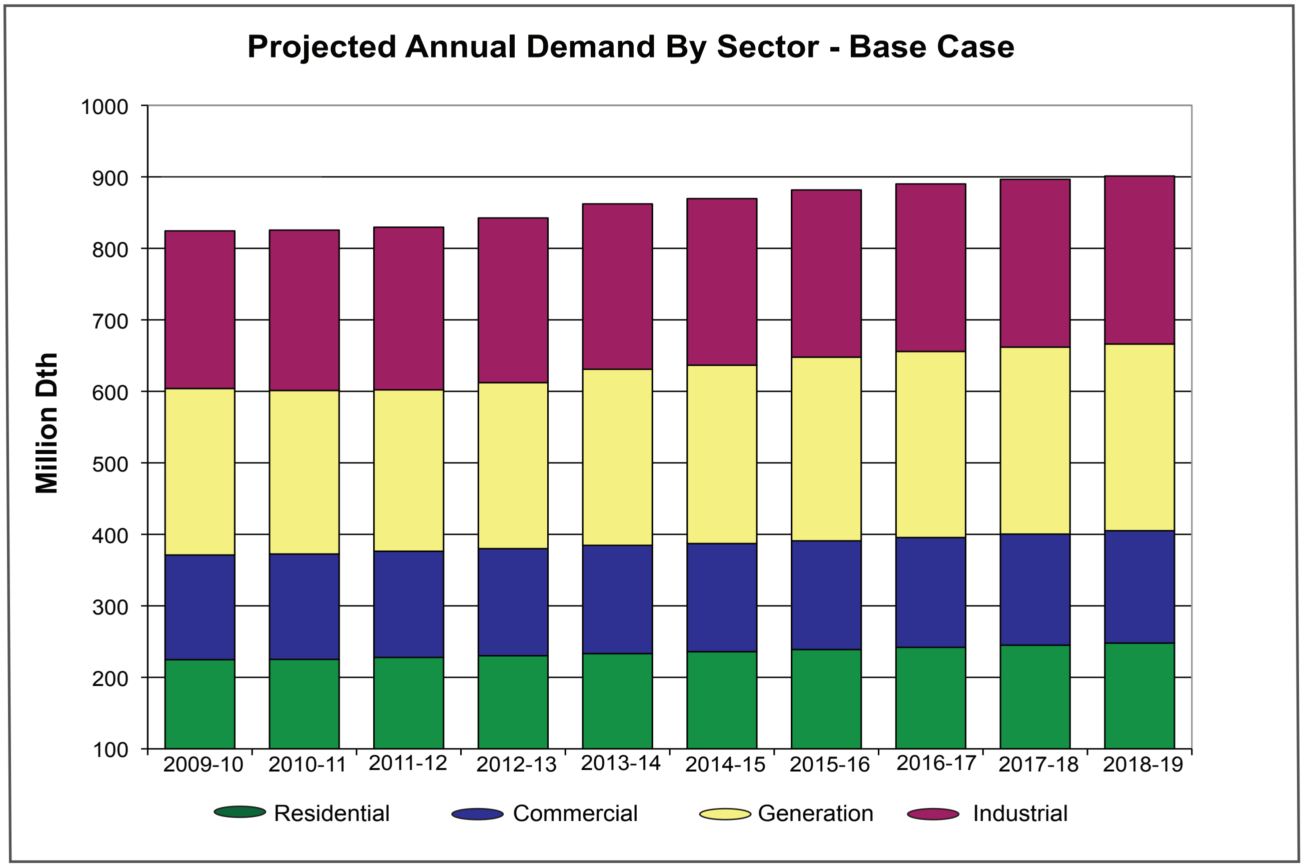
Figure 2 illustrates projected growth by sector in the base case, while Figure 3 shows projected total annual base case demand growth for each of the next 10 years. Figure 4 depicts projected annual demand under each of the three growth scenarios. All three figures demonstrate the effect of the recent recession, reflecting a decline of a little over 10 percent in the reference case from 2008 actual demand to 2009-10 projected demand.

FIGURE 2. PROJECTED REGIONAL DEMAND BY SECTOR – BASE CASE, 2009-2019



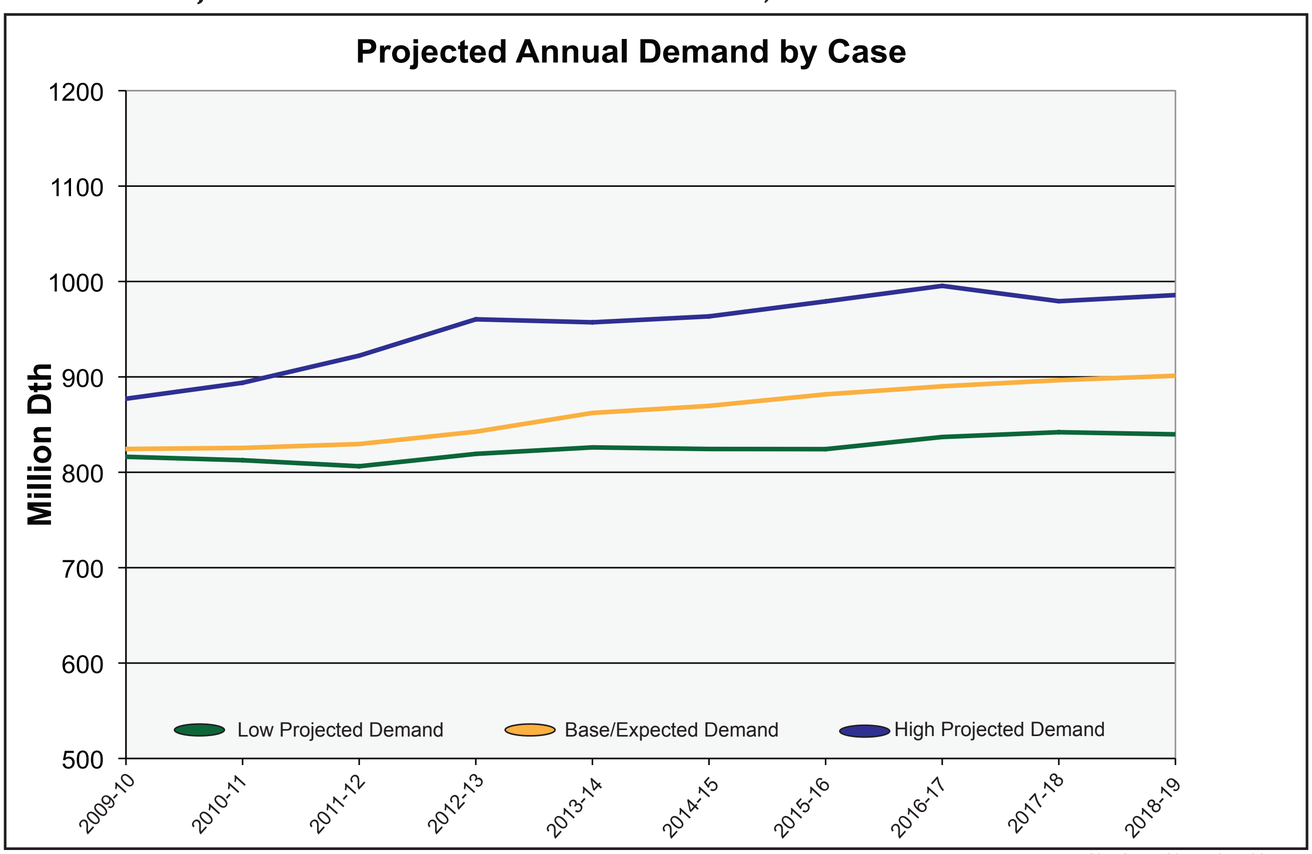
SOURCE: NWGA

FIGURE 3. PROJECTED TOTAL ANNUAL NATURAL GAS DEMAND GROWTH, BASE CASE 2009-2019



SOURCE: NWGA

FIGURE 4. PROJECTED ANNUAL DEMAND BY GROWTH CASE, 2009-2019



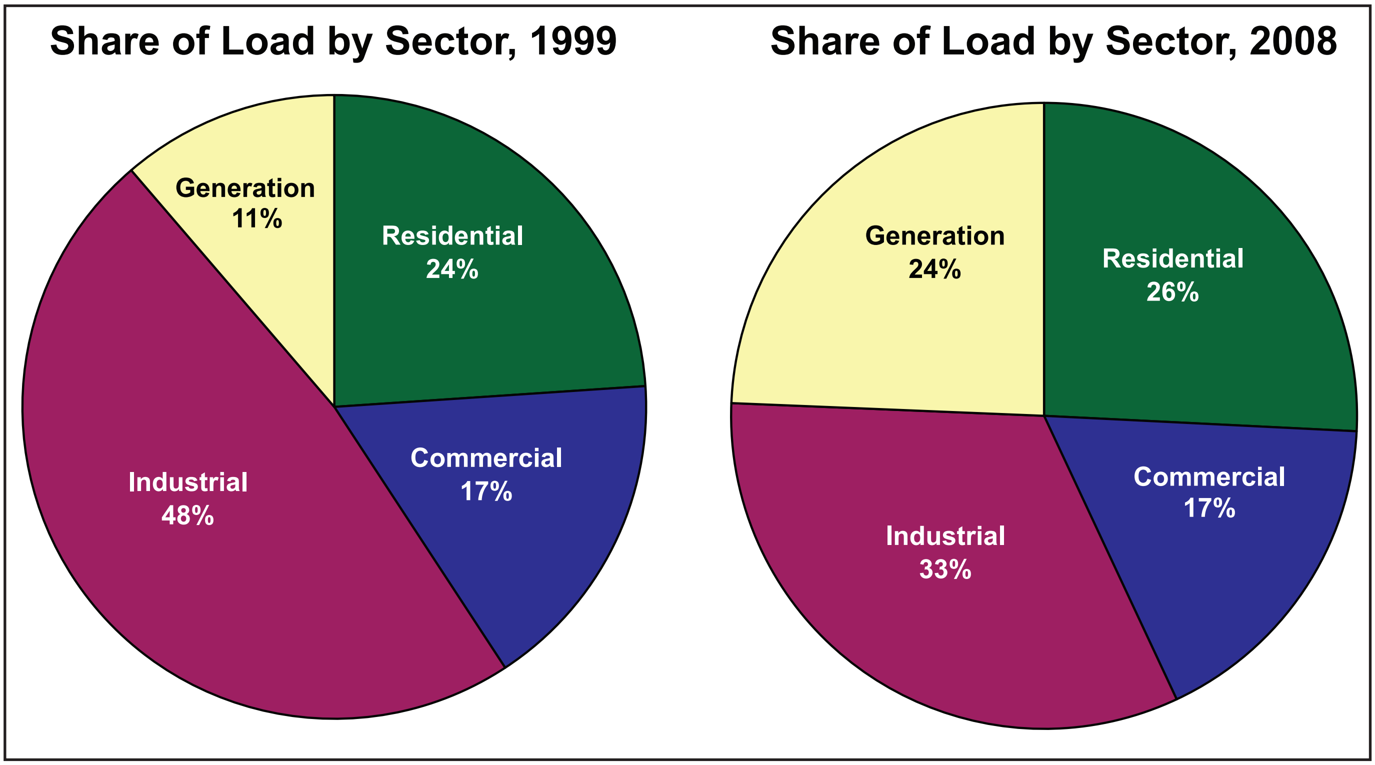
SOURCE: NWGA 2009 OUTLOOK

TRENDS IN DEMAND GROWTH

While the region's natural gas consumption continues to grow, the nature of that consumption has changed in recent years. Increased energy conservation efforts triggered by recent high energy prices have not only slowed the rate of demand growth, but changed customer load profiles and composition (see Figure 5). Year-round or baseload demand (e.g., industrial processes only nominally affected by weather, including chemical processing, lumber-drying kilns and food processing boilers) are growing more slowly than peak demand triggered by weather or other short-term factors (e.g., home heating).

New energy policies and plans focused on reducing carbon and other GHG emissions will likely intensify this trend. We expect the region will require additional power resources to serve growth in electric baseload demand as well as weather-driven demand in the summer (air conditioning) and winter (electric heating). While energy efficiency/conservation efforts and renewable resources are figuring prominently in emerging policies and plans, those resources are primarily used to address baseload demand for power. To meet peak demand, particularly in the near term, it is generally recognized that natural gas resources are the cleanest, most economical and most reliable option.

FIGURE 5. CHANGE IN DEMAND COMPOSITION, 1999 ACTUAL - 2008 ACTUAL



SOURCE: NWGA

This change has important implications for the natural gas industry since it affects the region's infrastructure and purchasing requirements. For instance, storage facilities are a cost-effective method of meeting seasonal or short-term surges in natural gas demand, while pipelines are usually built to serve steadier, year-round loads. (See Chapter 3, Regional System Capacity.) What mix of infrastructure the region requires in the future will be dictated in part by these demand trends.

HOW NEW ENERGY POLICIES ARE DRIVING NATURAL GAS DEMAND

As policymakers continue to address climate change and enact laws that shape how we produce and use energy, all energy market participants are beginning to feel the impact. Whether policies mandate change (by requiring energy producers to reduce GHG emissions) or encourage it (through consumer grants or tax credits), they will increasingly determine the energy choices we make. And natural gas, as the cleanest-burning fossil fuel, will serve an important and growing role in these efforts.

FEDERAL POLICIES

The U.S. and Canadian federal governments are pursuing new comprehensive energy policies to encourage emissions reductions and development of "green energy" through a combination of directives and incentives. In the U.S. Congress, the proposed American Clean Energy and Security Act of 2009 (H.R. 2454, called "Waxman-Markey" for the bill's primary sponsors) was passed by the House of Representatives in June 2009. It calls for an 83 percent reduction in carbon emissions from 2005 levels by 2050. Meanwhile, the U.S. Senate is considering its own Cleaner, Secure, Affordable Thermal Energy Act (S. 1643) which offers, among other incentives, a 30 percent tax credit to help energy consumers convert a home heating system from fuel oil to a natural gas.[3] (According to the EIA, such a conversion reduces GHG emissions by 27 percent.) From the two bills, a new law is expected to emerge from Congress by 2010.

At the same time, the U.S. Environmental Protection Agency (EPA) has declared carbon dioxide and five other GHGs as "dangerous pollutants." This formal endangerment finding obligates the agency to regulate GHG emissions, even if Congress does not pass an energy bill.

In Canada, the House of Commons is considering a Climate Change Accountability Act (Bill C-311) which calls for GHG emission cuts of 80 percent below 1990 levels by 2050. Meanwhile, Canada's Regulatory Framework for Industrial Greenhouse Gas Emissions, finalized in 2008, already requires industrial emitters to reduce their emission intensities 18 percent below 2006 levels beginning in 2010, with 2 percent continuous improvement every year following.[4]

"It is clear that, after conservation and renewables, natural gas-fired generation is the most cost-effective resource option for the region in the near-term."

-- NWPCC, draft Sixth Northwest Power Plan.

STATE/PROVINCIAL POLICIES AND REGIONAL PLANS

Regionally, Pacific Northwest policymakers in the U.S. and Canada are already blazing trails to reduce GHG emissions. In the U.S., Washington and Oregon have both enacted standards requiring significant proportions of electricity to be generated by renewable resources. Both states also adopted standards that limit the emission of greenhouse gases by any new power generation resources to those of state-of-the-art gas-fired generation technology. Idaho enacted a two-year moratorium precluding the construction of any new coal-fired generation in the state. While the moratorium has since expired, the message was effectively delivered. Project developers in other jurisdictions have also canceled or slowed the development of coal-fired facilities due to the regulatory risk associated with GHG and mercury emissions.

In Canada, British Columbia (BC) issued an Energy Plan in 2007 that requires existing thermal generation plants to reach zero net GHG emissions by 2016 and all new power generation to have zero net emissions. The goal is to ensure clean or renewable power generation continues to account for at least 90 per cent of total generation. In 2008, BC became the first jurisdiction in North America to enact a consumer-based tax on carbon emissions. Local governments in BC have also signed on to a BC Climate Action Charter to make municipal operations carbon neutral by 2012.

To coordinate these efforts, seven Western states (including Oregon and Washington) and four Canadian provinces (including BC) are collaborating through the Western Climate Initiative, which has set an overall regional (aggregate) goal of reducing GHG by 15 percent below 2005 levels by 2020.

Reflecting these policies, the NWPCC unveiled its draft Sixth Northwest Power Plan in September, 2009. The plan calls for aggressive pursuit of conservation measures throughout the region, coupled with investment in renewable generation "as required by state renewable portfolio standards." It also expects the Northwest will require new natural gas-fired generating resources to help meet future power demand – to provide reliable 24/7 power until the renewables industry matures (e.g., methods to store erratic sources, such as wind power, are developed) and beyond, possibly to replace coal facilities if they are phased out due to GHG regulations.

[3] http://www.aga.org/ClimateEnergyPolicy.htm
[4] http://www.ec.gc.ca/doc/virage-corner/2008-03/pdf/541_eng.pdf

WHAT THIS MEANS

While energy conservation and developing environmentally friendly energy resources are central to emerging strategies to reduce GHG emissions, natural gas is repeatedly called upon to keep our homes and businesses heated and industries humming while these measures are phased in. Even after we've captured energy savings and technology progresses to make renewable resources more reliable, clean-burning gas is expected to continue to heat buildings, fire industrial processes and fuel power generation facilities for the foreseeable future.

The challenge is to ensure this valuable resource is used wisely. While natural gas is abundant, the process for extracting it from the ground is becoming more expensive. (See Chapter 2, Regional Natural Gas Supply.) Consumers should prioritize putting natural gas to its most environmentally beneficial and cost-effective uses.

Right Fuel, Right Use: Direct use of natural gas – for space and water heating, cooking, and to fuel vehicles – is the most environmentally beneficial and cost-effective way to use it.

We also need to step up efforts to make the direct use of natural gas even more efficient. Customers have already significantly curbed their natural gas usage in the region by installing more efficient furnaces, programmable thermostats and appliances, and weatherizing their homes and businesses. But the potential for more savings – directly or indirectly, as through electricity conservation – is significant. (The NWPCC estimates some 1,400 average megawatts (aMW) in energy savings can be captured in our region in the next five years through aggressive conservation efforts, equivalent to the power usage of more than one million homes.)

As important as conservation and energy efficiency efforts are to the region, so are innovative rate structures that help utilities carry out these efforts. Because traditional rate structures recover fixed costs on a sales volume basis, they provide little incentive for utilities to invest funds that promote energy efficiency. New rate structures that break the link between the volume of gas or electricity sold and recovery of fixed costs, called "decoupling," have already enabled several regional utilities to invest in technology and programs that further promote energy efficiency.

By encouraging the most efficient uses of natural gas through these programs, but also maintaining a natural gas system that can serve fluctuating power generation needs, the regional natural gas industry is committed to help the region achieve the ambitious new environmental standards set by state/provincial and federal energy laws.

The role natural gas can play in mitigating climate changes is discussed further in the white paper *Natural Gas and Climate Change in the Pacific Northwest*, posted at www.nwga.org.

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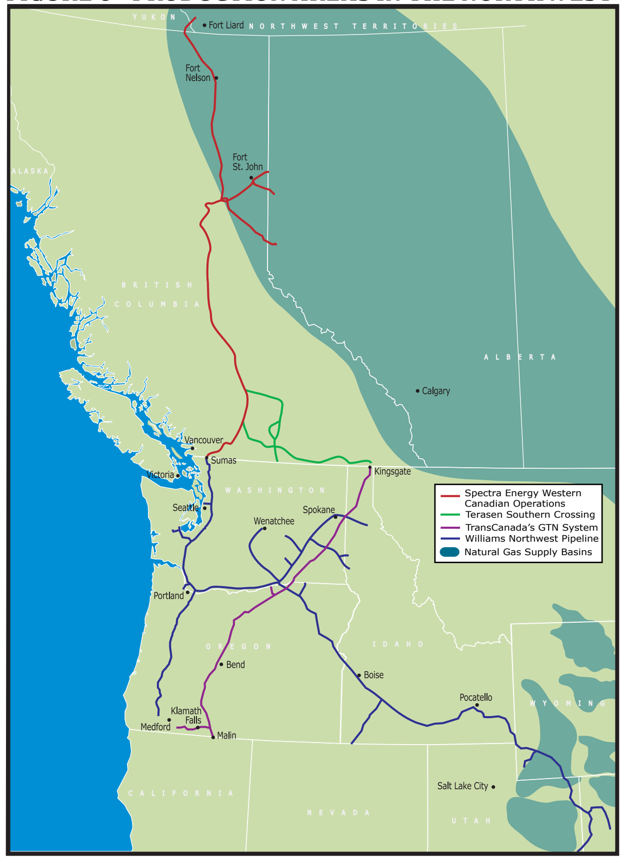
KEY CONCLUSIONS

1. Natural gas supplies are plentiful across North America and the world and include a variety of sources. Improved production technologies and market economics have recently spurred unprecedented recoverable natural gas discoveries across the continent.

2. The Pacific Northwest market continues to benefit from its proximity to the Western Canadian Sedimentary Basin (WCSB) and the U.S. Rockies (see Figure 6), two large and prolific gas-producing regions.

3. Competition for the supplies upon which the Northwest depends is intensifying as producers seek more lucrative markets and those markets seek access to lower-priced supplies – and pipelines are built to connect the two.

FIGURE 6 - PRODUCTION AREAS IN THE NORTHWEST



The Pacific Northwest currently relies on natural gas produced in the WCSB and the U.S. Rockies. More than half of the gas consumed in the region comes from the portion of the WCSB located in northeast BC and Alberta.

A CLOSER LOOK

North America is in the midst of a dramatic natural gas supply surge. Recent advances in drilling technology, coupled with higher natural gas prices in recent years, have made production of "unconventional" gas reserves economically viable. This has spurred development of plentiful shale gas reserves across the continent, as well as gas found in "tight sands" and coal bed methane (CBM) reserves. As a result, we have more supply available within the continent than projected even a year ago, with current estimates at more than 100 years worth of gas at current consumption levels.

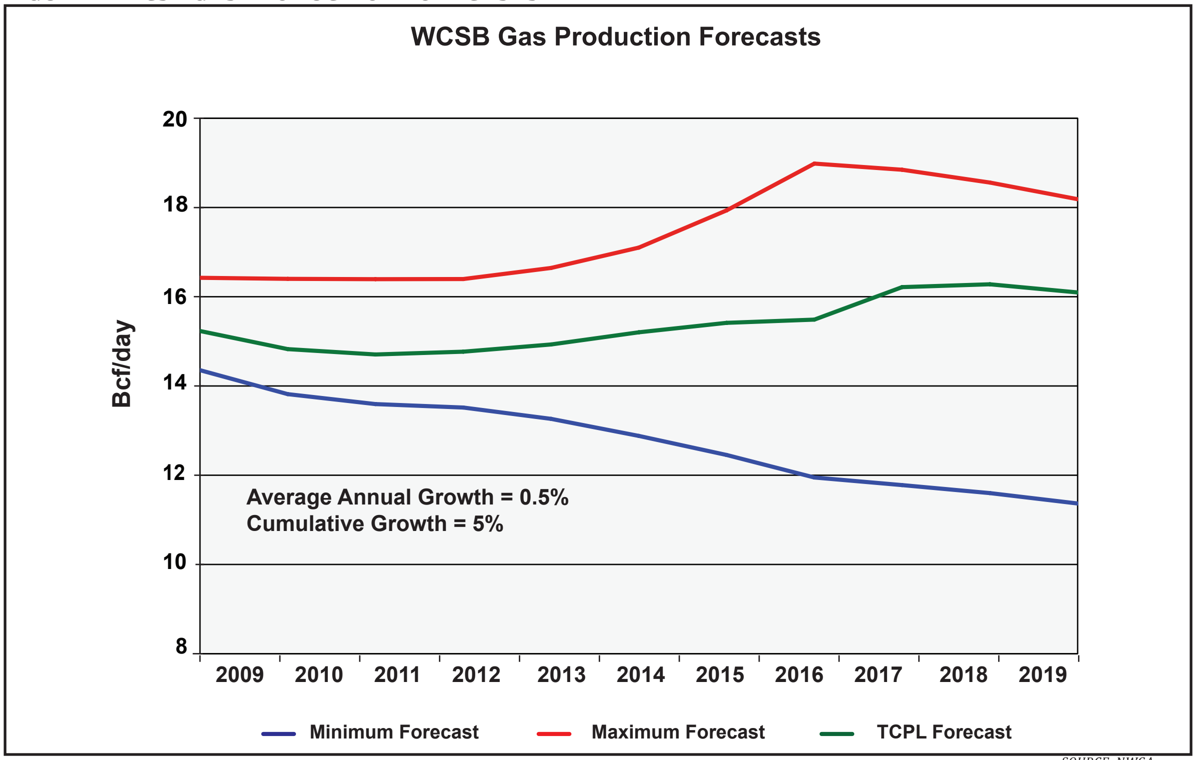
According to the Potential Gas Committee (PGC, administered by the Colorado School of Mines), the U.S. sits on top of massive reservoirs of natural gas – an estimated 1,836 trillion cubic feet (Tcf), of which shale gas accounts for one third.[5] That represents more energy than all the oil in Saudi Arabia. According to the Province of BC, northeastern BC alone contains more than 700 Tcf of unconventional gas potential, including some 250 Tcf of potential shale gas in the Horn River and Montney basins.[6] (Later estimates in 2009 project as much as 500 Tcf of potential shale gas in the Horn River region alone.[7]) Recoverable reserves from these sources are expected to be from 10 to 25 percent.

This is good news for Pacific Northwest gas consumers, because much of that growth is occurring in the two production areas already serving the region – the WCSB and Rockies. Currently, total annual natural gas production in these two areas is almost 26 billion cubic feet per day (Bcf/d). According to some estimates this could approach or even exceed 30 Bcf/d by 2019, largely due to unconventional gas development. Forecasts for production from the Rockies suggest continued strong growth. The average of Rockies production forecasts represents an increase of almost 16 percent, or 1.7 percent annually, through 2019.[9]

[5]PGC *Potential Supply of Natural Gas in the United States,* Dec 31, 2008.
[6]Province of BC, Ministry of Energy, Mines and Petroleum Resources, *An Overview of Shale Gas Potential in Northeast BC*, presentation during the 10th Western Canada Sedimentary Basin Workshop, June 2009, Victoria, BC.
[7]Reuters news release, *Encana says Horn River ranks high as shale gas find*, Sept. 9, 2009.

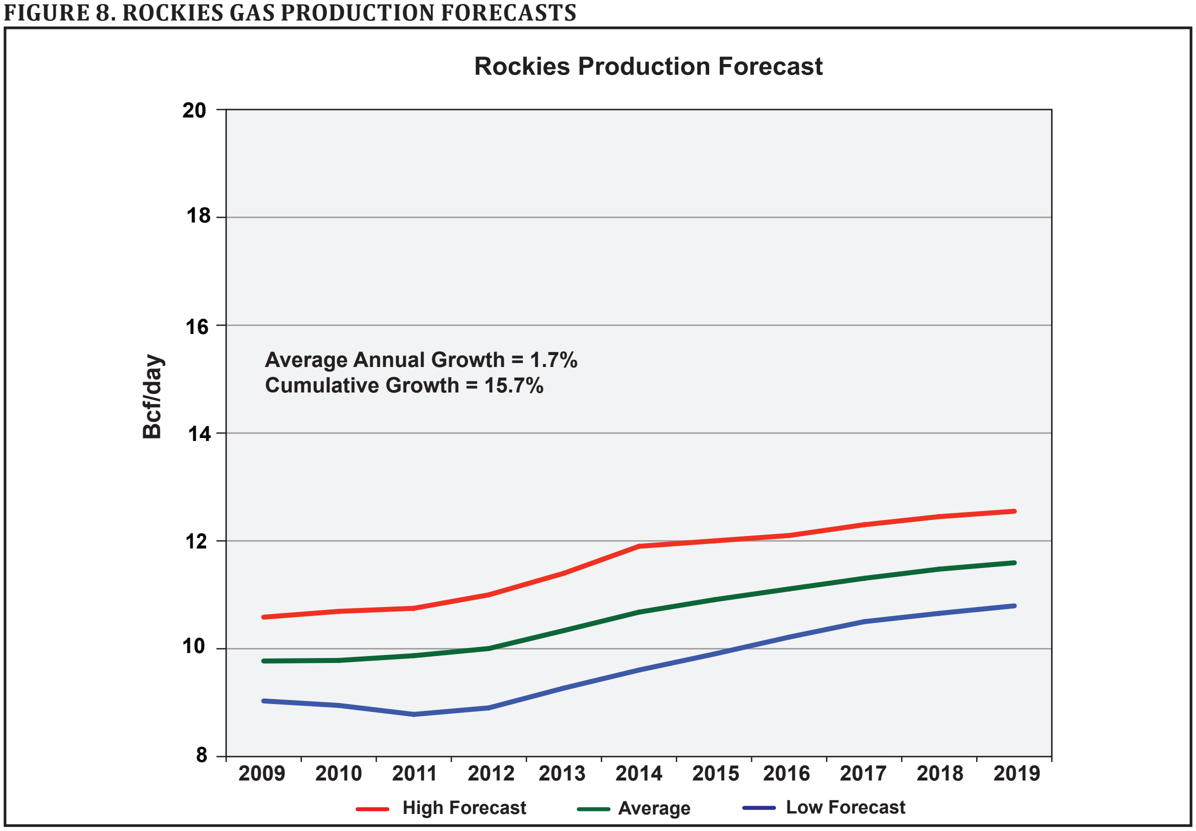
Figures 7 and 8 illustrate production forecasts in each area. As Figure 7 illustrates, there are a variety of production projections for the WCSB. TransCanada (an NWGA member) represents a middle path, projecting WCSB production to grow about 5 percent over the forecast period. In every case, the development of significant shale gas resources mitigates conventional production declines in the WCSB.

FIGURE 7. WCSB GAS PRODUCTION FORECASTS[8]



SOURCE: NWGA

FIGURE 8. ROCKIES GAS PRODUCTION FORECASTS



SOURCE: NWGA

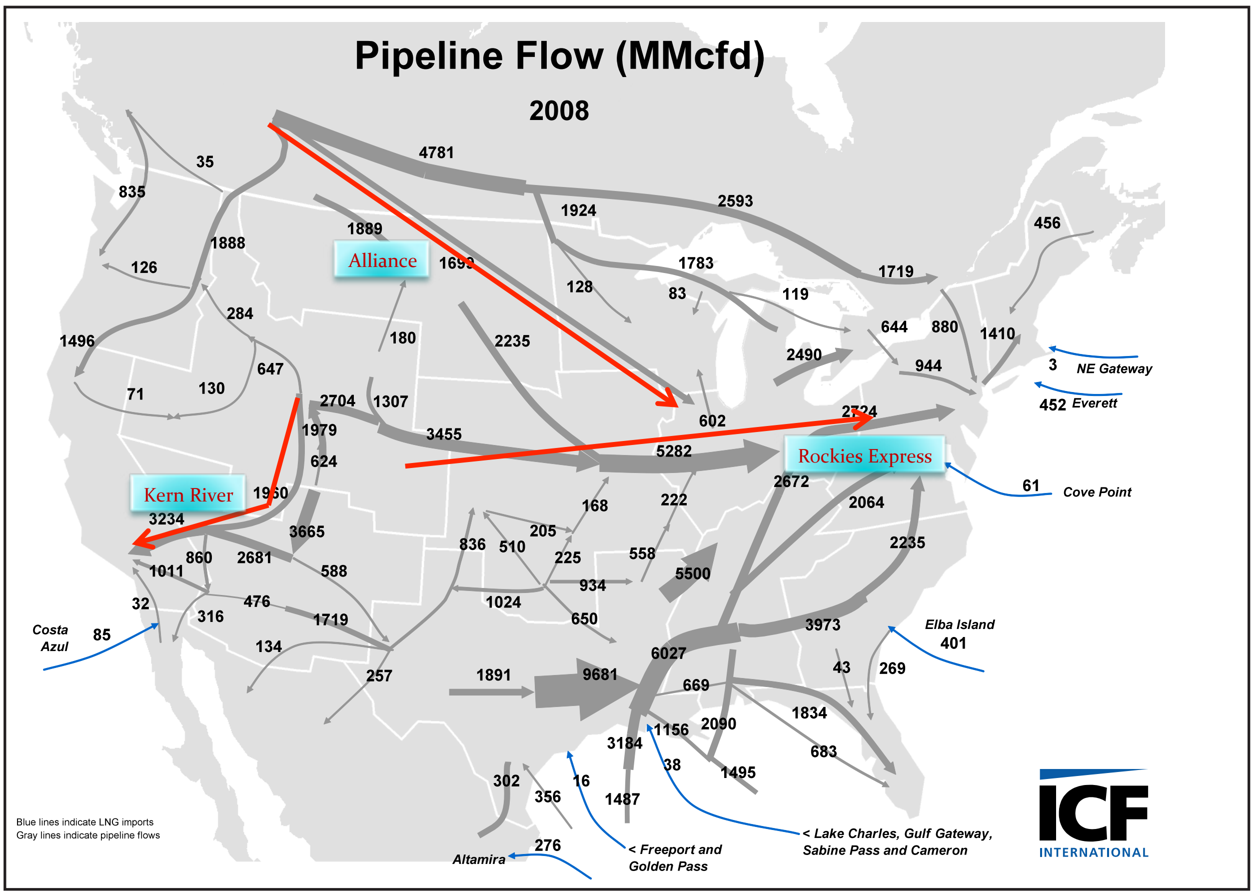
[8]The high and low data points in Figures 7 and 8 represent projections by professional forecasting services available from proprietary sources.

To ensure they have access to growing production in these areas, market participants in the region are investigating the viability of contracting for available capacity on existing pipelines and developers are proposing new infrastructure. (See Chapter 3, Regional System Capacity.)

It is important to keep the abundance of gas in perspective. First, market conditions that made more expensive drilling techniques pencil out for producers – and led to plentiful gas supply – have changed in the past year. Record high prices that approached $13/Dth in the summer of 2008 tumbled more than 80 percent, dropping below $2/Dth in September, 2009, before hovering around $3.50 through much of the fall. Some gas producers have since suspended drilling, with production expected to decrease through the rest of 2009 before picking back up in 2010.[9]

Second, while ample resources exist to serve our region, we are not the only market lining up for those supplies. The Pacific Northwest is increasingly competing with the rest of North America for supply from our key producing areas. (See Figure 9.) For example, the recently completed Rockies Express Pipeline (REX) stretching from Colorado to Ohio is sending about 1.8 Bcf/d of Rockies' gas to expanding markets in the Midwest and Northeast. Other examples: the Alliance Pipeline ships gas from northern BC and Alberta to Chicago, and the Kern River Pipeline moves Rockies' gas to Southern California and the desert Southwest. In short, more competition for gas supplies from existing sources means the Pacific Northwest is increasingly influenced by continental market dynamics and price fluctuations.

FIGURE 9. NORTH AMERICAN NATURAL GAS FLOWS



Large markest in the Midwest and East draw gas from across North America. Recently built major pipelines in the Rockies and WCSB move gas away from the Northwest.

[9] U.S. Energy Information Administration (EIA) *Short-Term Energy Outlook*, Aug. 11, 2009.

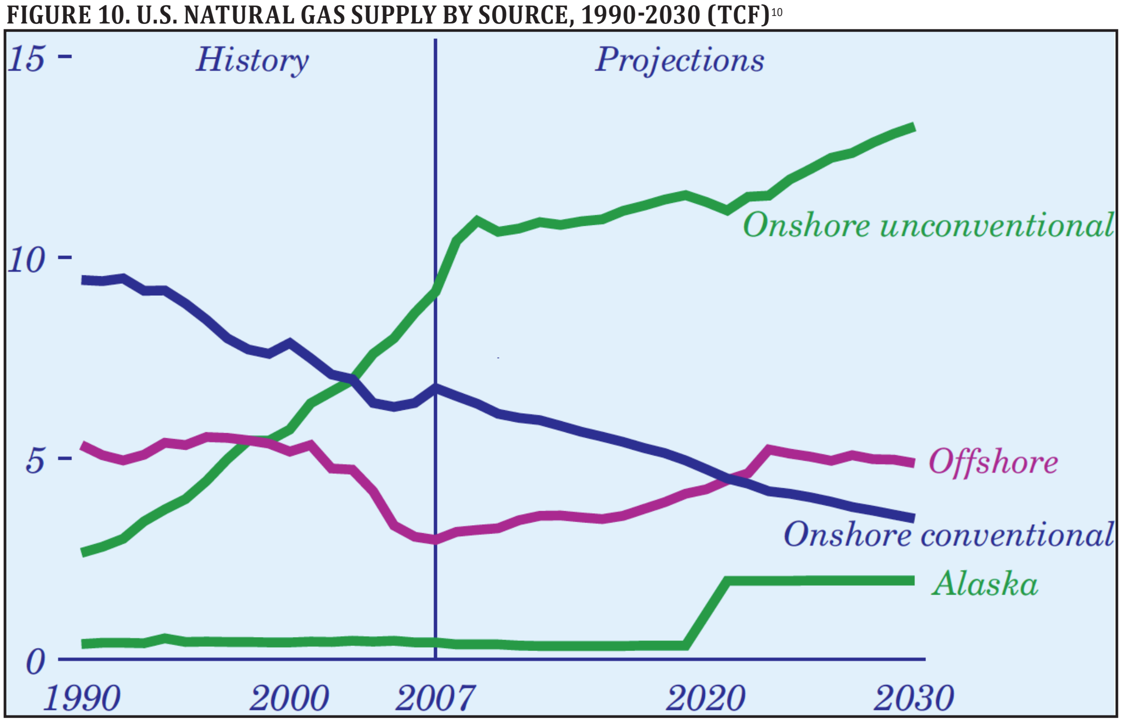
WHAT THIS MEANS

Natural gas consumers in the Pacific Northwest will continue to benefit from the region's location adjacent to two robust natural gas production areas for many years to come. Development of unconventional gas supplies in these areas has only made the situation better, although we are also facing more competition for those resources.

But wise consumers take a long-term view. What may be true now – plentiful supplies and low prices – can't be counted on to last, particularly in a market that is influenced by so many factors, including the economy (local and global) and the weather.

To stabilize our energy future, and ensure access to a variety of cost-effective resources, some market players are already pursuing access to other sources of natural gas. Besides unconventional gas development, options being pursued include offshore resources, frontier gas access and LNG imports. (See sidebar on page 13.) The EIA's projections for natural gas supply from each of these resources (excluding imported LNG) are shown in Figure 10.

FIGURE 10. U.S. NATURAL GAS SUPPLY BY SOURCE, 1990-2030 (TCF)[10]



Historically, many hurdles have slowed gas producers from exploring new development, including regulatory barriers and localized opposition. As the environmentally friendly attributes of clean-burning natural gas have become better understood, however, the tide of public opinion has changed, driving policymakers to address some of these obstacles (e.g., lifting offshore drilling moratoria).

Thanks to new drilling technology and changing policies, we may soon have diverse options for balancing future natural gas supply with growing demand, resulting in a cost-effective and environmentally sound mix of natural gas resources to serve future generations.

[10] EIA, *2009 Annual Energy Outlook* (March 2009), Figure 66.

POTENTIAL SOURCES OF ADDITIONAL SUPPLY

In addition to unconventional (shale, tight sands and CBM) natural gas resources, the region's future natural gas portfolio could include:

Frontier gas supplies – The Mackenzie River Delta (Canada) and the Alaska North Slope contain some 65 Tcf[11] and 35 Tcf[12] in reserves, respectively. Pipelines are being proposed that could potentially bring this gas to the lower 48 within the next decade.

Offshore resources – An estimated 420 Tcf of natural gas sits immediately offshore in the U.S., and another 43 Tcf off the BC coast, but drilling restrictions made them inaccessible. Both the U.S. and Canadian governments have recently taken steps to allow limited offshore development, reversing years of moratoria.

Liquefied natural gas (LNG) – Proven natural gas reserves elsewhere around the globe approach 4,000 Tcf.[13] Currently, LNG imports serve 1.5 percent of U.S. natural gas requirements. But technology improvements and growing worldwide demand for clean-burning natural gas have made the full-cycle cost of LNG more competitive, spurring development of new global LNG capacity. Dozens of new import terminals have been proposed across North America, including three in Oregon.

North American supply developments notwithstanding, LNG will serve a key role in the continental and regional energy picture over the long term. In the U.S., LNG imports are expected to increase from 500 Bcf in 2009 to nearly 1 Tcf by 2015.[14]

[11] National Energy Board (NEB), Canada.
[12] U.S. Department of Energy (DOE), Office of Fossil Energy.
[13] EIA 2009 International Energy Outlook (IEO). (World reserves estimated at 6,254 Tcf, minus 2,500 Tcf estimated within U.S. and Northeastern BC, equals approx. 3,754 Tcf throughout rest of world.)
[14] EIA *Updated 2009 Annual Energy Outlook* (April 2009)

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KEY CONCLUSIONS

1. The region's growing dependence on natural gas to help meet its environmental goals will drive the need for additional infrastructure to access more gas from traditional and new sources.

2. During extreme weather events (peak days), the existing system of natural gas pipelines and storage facilities serving the Northwest is efficiently utilized with little redundancy.

3. Infrastructure developers have responded to the region's emerging need by proposing several projects to deliver more supplies to the region from a diversity of sources, which can be built as market conditions dictate.

A CLOSER LOOK

Currently, pipelines and storage facilities serving the Pacific Northwest are capable of delivering more than 6.3 million Dth/day of natural gas at peak capacity. The region's 44,000-mile network of transmission and distribution pipelines is designed to meet the Northwest's baseload demand requirements on an ongoing basis, while underground and LNG storage assets provide a cost-effective means of meeting intermittent weather-driven needs (e.g., winter heating loads). Together, pipelines and storage give the industry flexibility in serving dynamic customer demand.

FIGURE 11. KEY INFRASTRUCTURE SERVING THE NORTHWEST

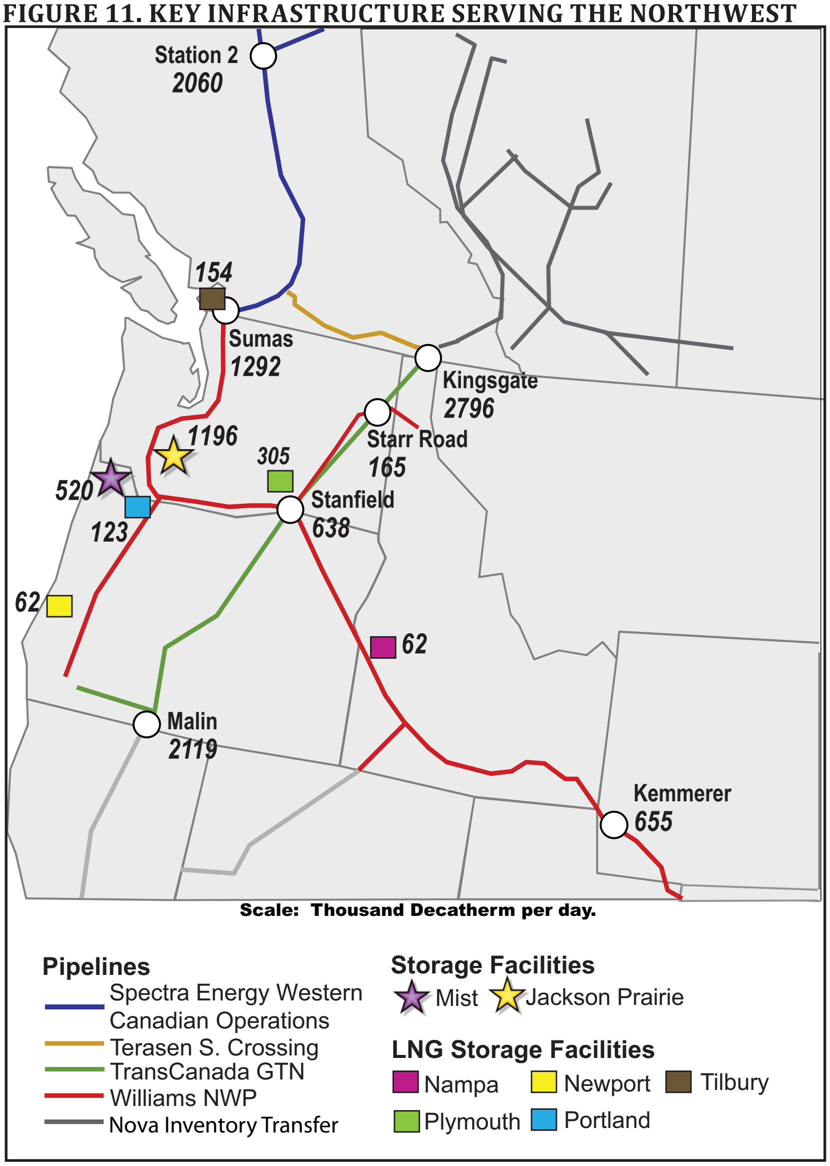


Figure 11 shows the current delivery capacity of pipelines and storage facilities serving the region in thousands of Decatherms per day (MDth/day). The region's pipeline operators completed major pipeline expansions in the 1990s through 2003 and are now exploring additional expansions (detailed later in this chapter).

In addition, completed and ongoing storage expansions will increase the region's peak day delivery capacity to almost 6.5 million Dth/day by 2012. As the region's peak demand continues to grow faster than baseload demand, the ability to store gas in the region becomes more and more valuable as a cost-effective means of meeting peak market needs.

If demand for natural gas grows as expected (per this Outlook's "base case" scenario), this regional network of infrastructure appears sufficient to serve average regional needs for the next few years. While the pipeline carrying gas west from the Rockies' production area is fully contracted, pipes carrying WCSB gas south to the region are not. However, available capacity on these pipelines is more fully utilized during high demand periods. The pipeline flowing south through central BC, for example, has reached full capacity during peak demand periods in recent years.

Eventually the region will need to build additional capacity to serve growing demand, including natural gas for power generation – an important component of the region's climate change strategy.

PEAK DAY ANALYSIS

The NWGA studied potential region-wide and area-specific peak capacity needs in the event of extreme events (e.g., extremely cold weather or low-water years that restrict hydropower availability) to assess when existing infrastructure could be stretched to its limits.

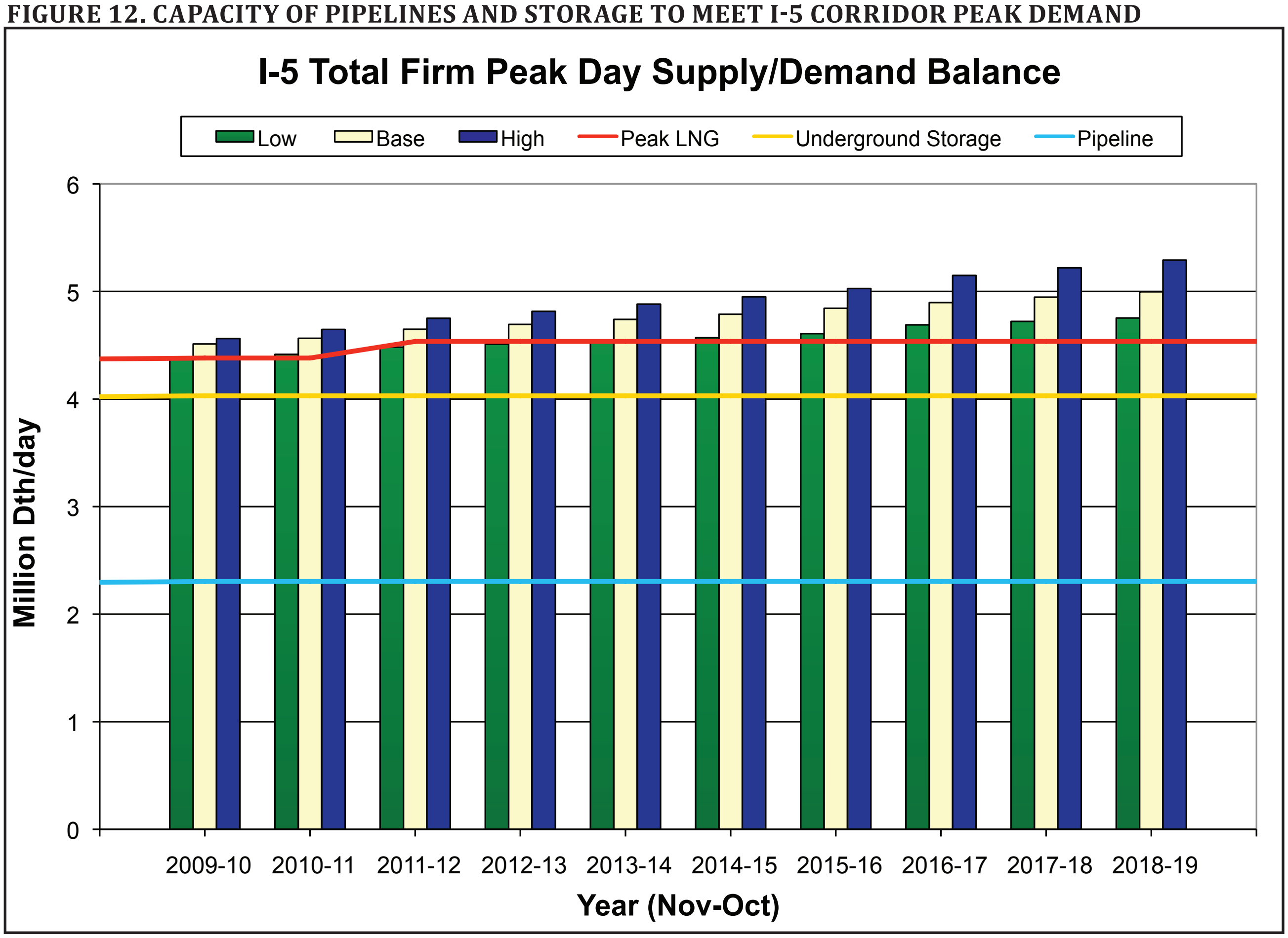
If the coldest days planned for by each NWGA member (called peak or design days) occurred simultaneously across the region, the resulting peak demand would be the highest possible – a "perfect storm."

Since weather patterns tend to roll across the Northwest, however, it is improbable that the entire region would experience respective design days simultaneously.

It is more likely that the I-5 Corridor (the area that includes most of the region's demand – see adjacent map) could experience extremely cold weather all at once. To replicate that scenario, the NWGA examined capacity levels needed if design days occur coincidentally across this sub-region. Assuming all facilities are available and working, Figure 12 shows that the system is efficiently utilized with no excess capacity for significant new demand – one factor driving recent and proposed capacity expansions in the region.

Of course, extreme weather is more likely to affect only parts of the region and usually in succession, not simultaneously. It is important to note that utilities include worst case scenarios in their planning to ensure that residential and commercial customers get the gas they need even in extreme circumstances. There is a chance, however, that during such events industrial customers or electricity generators without firm service agreements could face service curtailments.

FIGURE 12. CAPACITY OF PIPELINES AND STORAGE TO MEET I-5 CORRIDOR PEAK DEMAND



SOURCE: NWGA

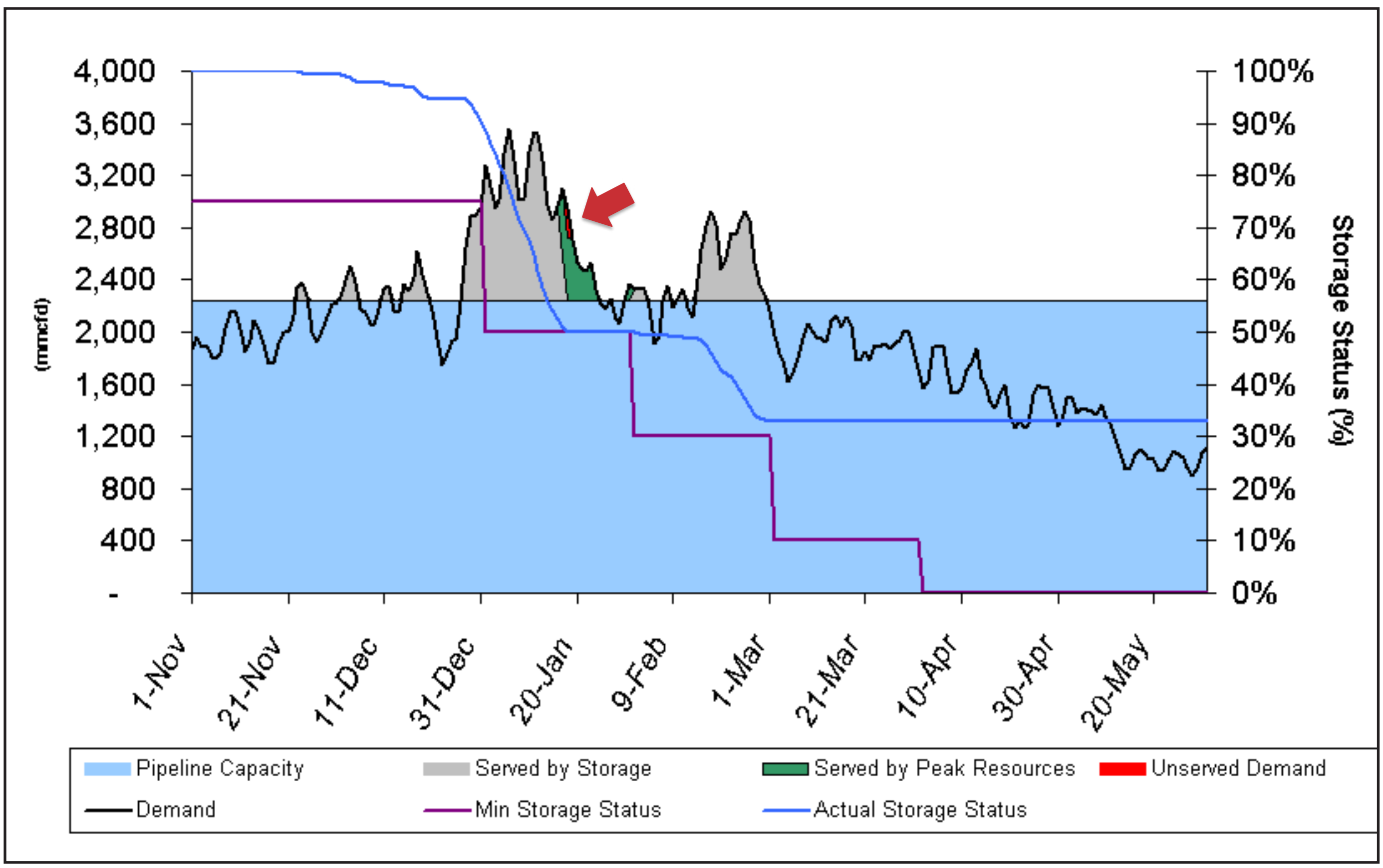
I-5 Corridor Extended Winter Analysis

The NWGA also conducted analyses of winter supply and demand for normal, moderately cold, and low-hydro years in the I-5 Corridor over this Outlook planning horizon, under a range of potential regional growth scenarios. The temperature in a moderately cold year differs depending on the specific region but occurs 15 percent of the time, or once every seven or eight years. A low-hydro year is one in which lower than average stream flows reduce hydroelectric generation and increase demand for gas-fired electric generation. The low-hydro year in this analysis was based on data from 2001, a near-critical water year.

For each of the scenarios, the low, base and high demand growth cases were plotted against pipeline capacity, underground storage and peaking resources such as LNG storage to gauge the adequacy of delivery capacity. The shapes of the winter demand curves were derived using analyses performed in 2004 and updated with the latest forecast of core, industrial and power generation demand included in the Demand chapter of this Outlook. The shape of core and power generation demand are different for a moderately cold year than for a normal or low-hydro year, while that for industrial load is the same.

Results of the analyses demonstrate that under normal weather conditions, existing infrastructure appears sufficient to meet demand under each growth case through the winter of 2018-19, assuming the I-5 Corridor's delivery capacity remains available at present levels, with no interruption of deliverability over the winter. However, Figure 13 plots projected demand from the high demand case against capacity resources for a moderately cold year at the end of the forecast horizon, indicating a small possibility of unserved demand (red area).

FIGURE 13. 2018-2019 WINTER ANALYSIS (BASE HIGH CASE DEMAND) – MODERATELY COLD YEAR



SOURCE: NWGA

"Unserved demand" in this analysis represents a decision point for system operators, who must determine how best to continue serving the most customers possible. They may decide to impose operational flow orders (OFOs), curtail customers using interruptible transport capacity, or ask for voluntary plant shutdowns. Some large customers with the ability to switch to other fuels for short periods may do so, although it is uncertain how much demand could be curtailed in this way. It is unlikely, however, that residential and commercial customers would experience service interruptions.

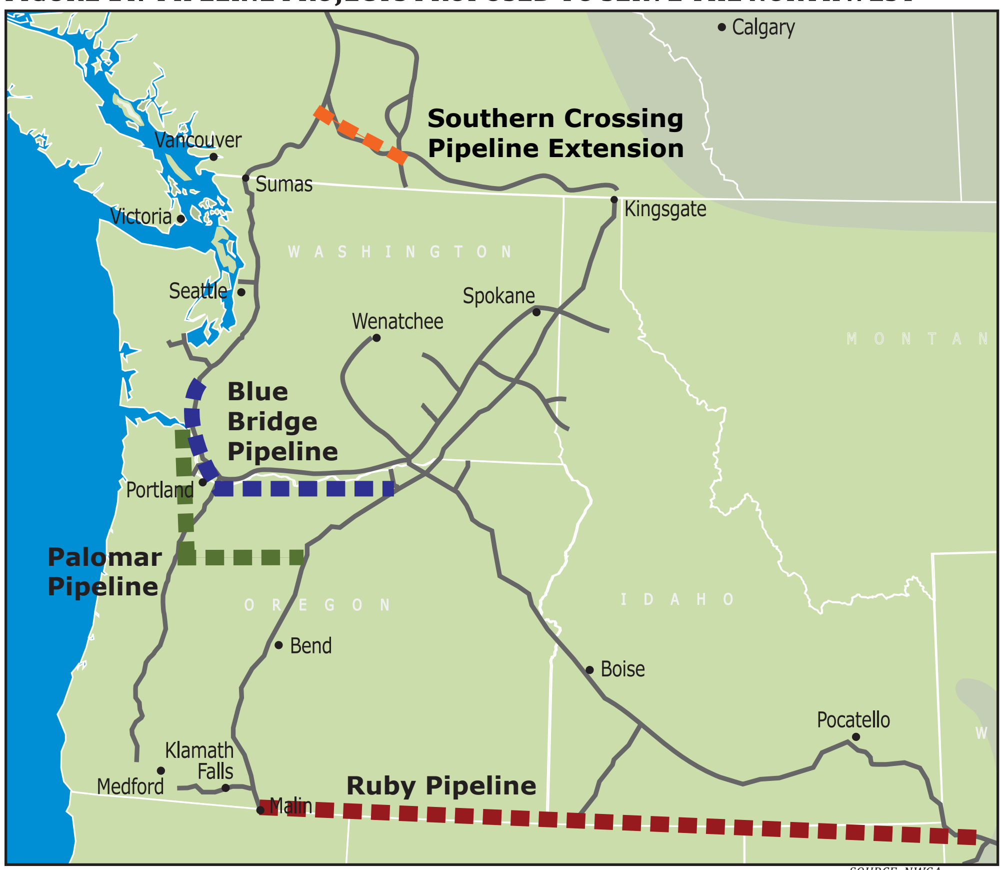
INFRASTRUCTURE PROJECTS AND EXPANSIONS

As the above analyses demonstrate, the region will eventually need new natural gas infrastructure. Already seeing the market signs of this need, infrastructure developers are pursuing several projects to add or expand delivery capacity. These efforts are expected to result in a mix of new pipelines, storage capacity and import terminals to serve the Northwest in the future. They will provide access to more gas from the abundant supply areas traditionally serving the region, and also the possibility of accessing new and emerging supplies across the continent and globe.

PROPOSED NEW PIPELINES

Four pipeline projects have been proposed to serve the region. (See Figure 14.) One, the Ruby pipeline, would expand western access to Rockies production areas. Sunstone, another project that would move gas west from the Rockies, was recently placed on hold until market conditions improve. The other three projects – Blue Bridge, the Southern Crossing Pipeline Extension and Palomar – are proposed to increase natural gas availability within the I-5 Corridor. Market dynamics will dictate which projects are ultimately built. Here is a brief look at each of the active proposals:

FIGURE 14. PIPELINE PROJECTS PROPOSED TO SERVE THE NORTHWEST



SOURCE: NWGA

Blue Bridge Pipeline – Williams/Northwest Pipeline is proposing this project, which includes building up to 119 miles of looping pipeline and installing additional compression. Project design continues to evolve, but is expected to deliver up to 300 MMcf/d from Plymouth, Wash., to the I-5 Corridor. The project would generally follow Northwest Pipeline's existing pipeline corridor for most of its route. FERC recently held public meetings on the project.

Palomar Pipeline – A partnership between NW Natural and TransCanada, Palomar Gas Transmission is proposing a 217-mile, 36-inch-diameter pipeline that would extend from TransCanada's GTN system near Madras, Ore., to the Columbia River near Clatskanie, Ore., where it would interconnect with the proposed Bradwood Landing LNG terminal. It would be a bi-directional pipeline with initial capacity of up to 1 Bcf/d. The project is configured as two segments. The Cascade segment would stretch from GTN to a point near Molalla (southeast of Portland), Ore., where it would connect with NW Natural's large-diameter system. The Willamette segment would run from Molalla to the Columbia River. The project's partners intend to build the Cascade segment irrespective of whether the LNG facility comes online. Federal approval to build is expected in late 2010.

Ruby Pipeline – El Paso Natural Gas is proposing to build this 675-mile, 42-inch diameter pipeline from Opal, Wyo., to Malin, Ore, with an initial design capacity of up to 1.5 Bcf/d. The project application has been filed with the Federal Energy Regulatory Commission (FERC); construction is expected to begin pending financing and final regulatory and environmental clearances.

Southern Crossing Pipeline Extension – Terasen Gas is exploring options to extend its Southern Crossing Pipeline from Oliver to Kingsvale, BC. Initial design capacity would be 200 MMcf/d, expandable to 400 MMcf/d. The project is bi-directional, allowing new production coming from northern BC to move into the eastern part of the region via the GTN system or move Alberta gas into the I-5 Corridor via the Spectra Energy system during peak periods.

PROPOSED LNG IMPORT TERMINALS AND PIPELINES

There are three LNG import terminal projects proposed in the region, all in Oregon: Bradwood Landing on the Columbia River near Clatskanie; Oregon LNG in Warrenton, and Jordan Cove in Coos Bay. In addition, Kitimat LNG is proposing an export terminal in Northwest BC to capitalize on new supply sources there.

Each LNG project includes one or more proposed pipelines that will be built if the associated terminal is built, including:

- The 291-mile Pacific Trail Pipeline would connect natural gas from Spectra Energy Transmission's pipeline at Summit Lake, north of Prince George, BC, to the proposed Kitimat LNG export terminal in BC's Bish Cove.
- A 117-mile pipeline would connect Oregon LNG's proposed terminal in Warrenton, Ore., to the existing NW Natural and Williams Northwest Pipeline systems near Molalla.
- The 231-mile Pacific Connector Gas Pipeline would extend from the proposed Jordan Cove LNG terminal in Coos Bay, Ore., across southwest Oregon to the California border at Malin, Ore., to serve the Pacific Northwest and California markets.

FIGURE 15. PROPOSED LNG TERMINALS & ASSOCIATED PIPELINES

STORAGE FACILITY EXPANSIONS

Currently, the region is served by almost 40 million Dth of working gas capacity (gas available to the marketplace – see Table 2) in underground natural gas storage facilities and over 5 million Dth of capacity in above-ground LNG peaking storage facilities (not to be confused with the larger scale LNG import facilities discussed earlier). Combined with regional pipeline delivery capacity, these storage facilities enable utilities and other market participants to serve the entire region's peak requirements for almost a week under all but the most extreme conditions.

To meet growing peak demand, several storage expansions were recently completed or are being considered in the near future. For example, NW Natural completed an expansion of its Mist gas storage field in northwest Oregon in 2007, adding new injection and withdrawal wells. Mist's storage capacity is now 16.3 million Dth. The facility also increased throughput to 530 MDth of gas per day.

TABLE 2. EXISTING PACIFIC NORTHWEST STORAGE AND LNG FACILITIES

Existing PNW Storage and LNG Facilities

Facility	Owner	Type	Capacity[1] (MDth)	Max Withdrawal (MDth/day)
Jackson Prairie, WA	Avista, PSE, NW Pipeline	Underground	24,300	1,196 [2]
Mist, OR	NW Natural	Underground	16,300	530 [2]
	Underground Subtotal		40,600	1,726
Plymouth, WA	NW Pipeline	LNG	2,388	305
Newport, OR	NW Natural	LNG	1,000	60
Portland, OR	NW Natural	LNG	600	120
Tilbury, BC	Terasen Gas	LNG	616	154
Nampa, ID	Intermountain Gas	LNG	588	60
Gig Harbor, WA	PSE	LNG	31	3
Swarr Station, WA	PSE	LPG[3]	130	10
Mt. Hayes, BC[4]	*Terasen Gas*	*LNG*	*1,540*	*154*
	LNG/LPG Subtotal		5,353	712
	TOTAL STORAGE (as of Sept. 30, 2009)		**45,953**	**2,438**

[1] Working gas capacity; gas that can be used to serve the market.
[2] Represents start of season or full rate; storage withdrawal rates vary with working gas volumes.
[3] LPG = Liquid Propane Gas and Air mixture
[4] Under construction; in-service date of 2011; volumes not included in totals

SOURCE: NWGA

In addition, the Jackson Prairie owners (Avista, Puget and Northwest Pipeline) are expanding the Jackson Prairie storage facility in southwest Washington. The facility's working capacity is expected to grow to 25.6 million Dth by 2012. Its withdrawal capability was increased from 884 MDth/d to 1,196 MDth/d in 2008.

Meanwhile, Terasen Gas broke ground in 2008 on its Mt. Hayes LNG storage facility designed to serve peak demand on Vancouver Island and BC's lower mainland region by winter of 2011-12. This facility will supplement several smaller LNG storage facilities already serving the region with peaking capacity.

WHAT THIS MEANS

Much like arteries in the human body, the region's natural gas pipelines serve a living, breathing market that is never static. Storage facilities serve as energy reserves to be called upon as needed. Together, the system keeps natural gas flowing to customers throughout the year and under a variety of conditions.

Growing regional demand for natural gas, now spurred by environmental mandates, is beginning to approach the limits of infrastructure available to serve it on peak days. At the same time, as noted in the Supply chapter, the region is facing more competition for its traditional supplies from other markets across North America. To keep gas flowing, we will eventually need to expand the capacity available to serve our market region. But these projects take time – at least three to five years.

Market participants have already responded to market signals that new capacity is needed by proposing a mix of solutions. And ultimately market players – industry participants, consumers, regulators and policymakers – will decide which projects move forward. The goal is a natural gas system that allows more choice and flexibility to optimize resources – to take advantage of the best value at any given time – and will ultimately benefit consumers with more stable prices (discussed in next chapter).

Capacity expansions take time – three to five years from initial planning to completion – and involve numerous steps, including assessing market interest, gathering public input, obtaining permits and financing, environmental mitigation, construction, safety inspections, remediation and more. Because of the time and complexity involved in putting these projects together, it's important to get started before the need physically exists. *(See the NWGA white paper on infrastructure at www.nwga.org for a more robust discussion of infrastructure development.)*

KEY CONCLUSIONS

1. Natural gas prices reflect the balance between demand and supply, which shifted significantly in the past year. High natural gas daily spot prices in North America during the summer of 2008 (~ $13/Dth) contrast sharply with the low daily spot prices experienced during the summer and fall of 2009 (at one point less than $2/Dth).

2. Policymakers can and will influence natural gas prices depending on whether and how they address critical issues affecting the supply/demand balance, including access to new sources of supply, infrastructure development and efficient use of natural gas.

A CLOSER LOOK

The economic recession that arrived with a fury in North America and across the rest of the globe during the past year had far-reaching impacts on natural gas demand. As businesses and homeowners economized, demand fell and prices followed. Hastening the descent of prices was a growing inventory of gas supply. Recent higher gas prices made it economical to develop more difficult-to-access resources (discussed in Chapter 3, Regionsl System Capacity), spurring a significant increase in production.

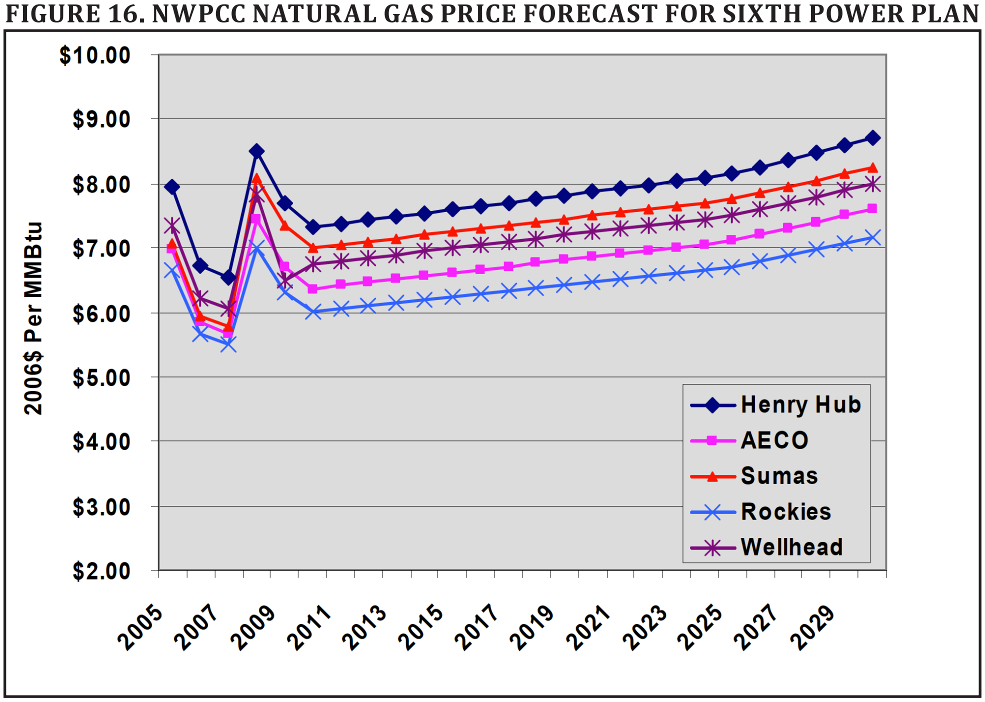
> Balancing growing demand with additional supplies is important to maintain price stability.

The result? The high natural gas prices of summer 2008 plummeted, bottoming out at less than $2/Dth ($1.85 at the Henry Hub trading point in September) before recovering slightly to spend most of the fall in the $3.50/Dth range.

While this was good news for consumers in the short-term, the steep descent in prices poses a dilemma for the natural gas market in the next few years. Producers have already responded to lower demand and prices by cutting back drilling and delaying new investments. In time, this will drive prices back up. Pacific Northwest consumers are not immune to these market dynamics, because we compete with other regions for what used to be our own “bubble” of supply. Prices could rebound quickly if all markets across the continent recover at the same time.

Figure 16 shows the NWPCC’s most recent “medium case” natural gas price forecast at several trading points as developed for its 2009 draft Sixth Northwest Power Plan. The NWPCC reviews a variety of sources and consults with a diverse group of regional stakeholders through its Natural Gas Advisory Committee to derive its Fuel Price Forecast. The forecast is then used in NWPCC models to project the reference (or expected) mix of sources of future electrical generation in the region (e.g., gas-fired combined cycle turbines, wind energy, coal, etc.).

FIGURE 16. NWPCC NATURAL GAS PRICE FORECAST FOR SIXTH POWER PLAN



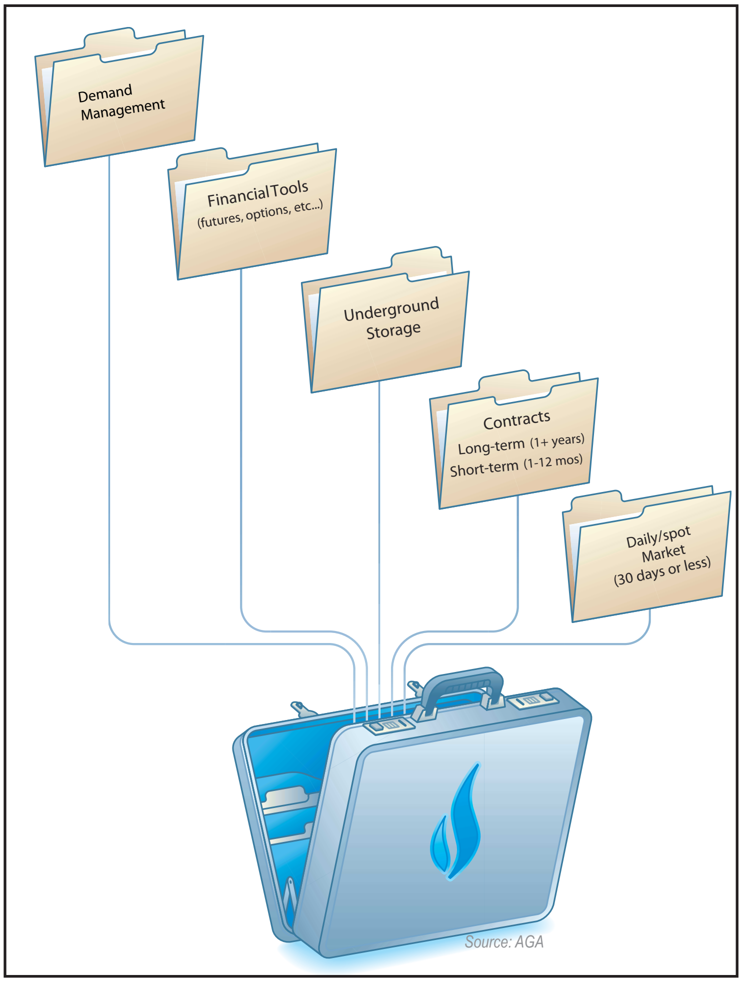
SOURCE: NWPCC

While no one can accurately predict weather events and global crises that affect energy prices, certain market influences can be foreseen. For example, we discuss in preceding chapters how energy policies aimed at reducing GHG emissions are expected to boost demand for natural gas because conservation and renewable energy sources alone cannot meet growing electricity demand. This will result in construction of more natural gas-fired generation. How this will affect Northwest gas prices will depend on natural gas production levels and whether our regional infrastructure expands appropriately to bring that gas here.

The supply side of the picture has also changed markedly over the last year. Shale gas potential in our region (NE BC) and across North America holds great promise for natural gas consumers.

To manage prices, local distribution companies (utilities) and power generators use portfolio management activities that mix short- and long-term purchases to balance risk. This allows them to acquire reliable resources to meet customer demand while minimizing price fluctuations and securing the most reasonable prices. Figure 17 illustrates a typical portfolio of resources.

FIGURE 17. INDUSTRY TOOLS TO MANAGE PRICES



WHAT THIS MEANS

Strategic planning by the natural gas industry cannot, itself, mitigate the higher prices being felt by Pacific Northwest and other North American natural gas consumers. The cost of finding and developing new supplies will establish new price floors that could be higher than historical prices. Further, public policies and the regulatory environment heavily influence the industry's ability to operate effectively – either expediting market flexibility or posing serious hurdles that can skew the demand/supply balance – and therefore can play a huge role in future gas prices.

Demand can change quickly – and will in response to new climate change policies – but it can take several years for new natural gas production and the infrastructure required to deliver it to come online. The licensing and construction of new infrastructure can be a three- to five-year effort.

Moderating future gas prices will require additional proactive steps by the industry and policy-makers on both sides of the equation – not only reshaping demand in more efficient and environmentally friendly ways – but encouraging development of and access to additional supply from diverse sources.

Additional information on prices, including key price drivers, can be found in the July 2008 white paper, *Natural Gas Prices in the Pacific Northwest*, posted on the NWGA Web site: www.nwga.org.

APPENDIX
DATA TABLES

Northwest Gas Association
2009 Natural Gas Outlook
Peak Day Supply

SUPPLY	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	40118	40148	40179
Pipeline Interconnects	**3,898,890**	**3,898,890**	**3,898,890**	**3,898,890**	**3,898,890**	**3,898,890**	**3,898,890**	**3,898,890**	**3,898,890**	**3,898,890**
WCSB via TCPL/GTN	**1,420,625**	**1,420,625**	**1,420,625**	**1,420,625**	**1,420,625**	**1,420,625**	**1,420,625**	**1,420,625**	**1,420,625**	**1,420,625**
Stanfield (NWP from GTN)	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*
Starr Rd (NWP from GTN)	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*
Palouse (NWP from GTN)	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*
GTN Direct Connects	*415,000*	*415,000*	*415,000*	*415,000*	*415,000*	*415,000*	*415,000*	*415,000*	*415,000*	*415,000*
Kingsgate/Yahk BC Interior from TCPL	*182,625*	*182,625*	*182,625*	*182,625*	*182,625*	*182,625*	*182,625*	*182,625*	*182,625*	*182,625*
Rockies via NWP	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**
NWP north from NWP south	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*
Max Demand on Reno Lateral	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*
WCSB via DEGT	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**
T-South to Huntingdon	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*
T-South to BC Interior	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*
T-South to Kingsvale	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*
Southern Crossing to Huntingdon	-	-	-	-	-	-	-	-	-	-
Storage	**2,442,088**	**2,442,088**	**2,596,588**	**2,596,588**	**2,596,588**	**2,596,588**	**2,596,588**	**2,596,588**	**2,596,588**	**2,596,588**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
(includes deliverability expansion of 312,000 Dth/day in service 2008-09)										
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450
(includes deliverability expansion of 51,310 Dth/day in service 2007-08)										
Plymouth (NWP from LNG)	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Nampa LNG (IGC)	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (TGI)	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338
Vancouver Island LNG (permitted, provisional)	-	-	154,500	154,500	154,500	154,500	154,500	154,500	154,500	154,500
Total Available Supply	6,340,978	6,340,978	6,495,478	6,495,478	6,495,478	6,495,478	6,495,478	6,495,478	6,495,478	6,495,478

A2. ANNUAL DEMAND BY REGION AND SECTOR, BASE CASE

Northwest Gas Association
2009 Natural Gas Outlook
Annual Demand Summary (Dth) - Base Case

Region/Sector	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
BC Lower Mainland & Van. Island	**143,531,064**	**143,582,590**	**143,730,427**	**143,908,052**	**144,097,739**	**142,464,491**	**141,741,912**	**141,985,944**	**142,175,925**	**142,373,352**
Residential	53,304,319	52,960,224	52,635,233	52,311,649	51,989,674	51,576,685	51,441,383	51,372,506	51,287,482	51,208,289
Commercial (Sales)	38,743,909	39,156,976	39,597,083	40,042,280	40,497,931	39,191,920	38,690,296	38,986,038	39,261,043	39,537,663
Industrial (Transport & Interruptible)	32,058,370	31,946,142	31,978,863	32,034,874	32,090,886	32,176,638	32,090,984	32,108,151	32,108,151	32,108,151
Power Generation	19,424,467	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248
W. Washington	**257,942,363**	**259,986,095**	**261,042,084**	**267,777,572**	**273,067,703**	**277,704,015**	**287,547,011**	**290,798,116**	**291,689,281**	**294,808,259**
Residential	68,588,736	69,484,466	71,169,290	72,508,524	74,284,490	76,064,710	77,860,720	79,602,462	81,287,337	82,842,153
Commercial (Sales)	42,116,261	42,455,464	42,212,528	42,293,556	42,663,106	43,169,419	43,802,048	44,463,602	45,178,457	45,877,996
Industrial (Transport)	73,604,409	73,232,978	72,952,723	72,897,723	72,836,434	72,820,439	72,850,466	72,905,186	72,946,986	73,025,171
Power Generation	73,632,957	74,813,188	74,707,544	80,077,769	83,283,674	85,649,447	93,033,777	93,826,866	92,276,502	93,062,938
W. Oregon	**118,130,747**	**120,800,069**	**124,401,210**	**127,389,155**	**128,940,436**	**130,435,688**	**132,246,901**	**133,281,626**	**134,401,509**	**135,469,911**
Residential	37,410,595	37,799,359	38,642,952	39,265,435	40,027,552	40,786,527	41,884,857	42,621,892	43,507,553	44,397,426
Commercial (Sales)	23,973,033	24,049,268	24,334,961	24,380,834	24,456,522	24,537,857	24,818,399	24,898,044	25,057,506	25,222,056
Industrial (Transport & Interruptible)	38,176,360	40,701,441	43,173,297	45,492,887	46,206,362	46,861,305	47,293,645	47,511,690	47,586,450	47,600,428
Power Generation	18,570,759	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000
BC Interior	**44,300,721**	**44,127,069**	**44,509,923**	**44,894,595**	**45,262,104**	**45,968,407**	**46,224,324**	**46,368,174**	**46,452,419**	**46,524,562**
Residential	16,395,274	16,244,945	16,318,911	16,476,065	16,637,526	16,560,670	16,523,731	16,524,784	16,483,775	16,432,907
Commercial (Sales)	10,352,860	10,546,511	10,742,088	10,942,647	11,148,111	11,209,422	11,295,964	11,438,762	11,564,016	11,687,027
Industrial (Transport & Interruptible)	17,552,587	17,335,613	17,448,924	17,475,883	17,476,467	18,198,316	18,404,628	18,404,628	18,404,628	18,404,628
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**86,693,760**	**85,344,139**	**84,686,877**	**85,475,309**	**86,085,819**	**87,116,716**	**87,126,692**	**88,505,653**	**90,026,407**	**90,422,493**
Residential	19,006,181	18,781,816	18,795,354	18,895,236	19,057,678	19,235,714	19,095,938	19,191,761	19,330,164	19,486,445
Commercial (Sales)	14,041,407	14,170,534	14,386,123	14,628,548	14,909,239	15,198,030	15,297,003	15,526,258	15,786,337	16,058,035
Industrial (Transport & Interruptible)	28,797,212	29,060,644	29,321,389	29,532,820	29,748,070	29,960,302	30,159,539	30,347,072	30,543,696	30,745,716
Power Generation	24,848,960	23,331,146	22,184,011	22,418,705	22,370,833	22,722,670	22,574,211	23,440,562	24,366,209	24,132,296
E. Oregon & Medford	**116,543,750**	**113,205,167**	**111,868,510**	**113,122,115**	**113,449,592**	**114,220,150**	**114,714,948**	**116,640,603**	**118,786,974**	**118,099,143**
Residential	8,053,453	8,127,858	8,296,766	8,490,965	8,691,394	8,894,899	9,045,686	9,242,408	9,433,222	9,615,629
Commercial (Sales)	5,737,392	5,790,141	5,870,720	5,957,818	6,035,384	6,108,330	6,155,159	6,223,806	6,292,402	6,357,917
Industrial (Transport & Interruptible)	8,530,653	8,684,099	8,869,358	8,952,583	9,014,300	9,037,917	9,055,026	9,070,614	9,087,807	9,104,282
Power Generation	94,222,252	90,603,069	88,831,666	89,720,749	89,708,514	90,179,005	90,459,077	92,103,775	93,973,544	93,021,314
S. Idaho	**57,308,594**	**58,505,773**	**59,382,107**	**59,969,910**	**71,308,190**	**71,685,271**	**72,091,989**	**72,546,384**	**73,006,719**	**73,473,072**
Residential	22,051,636	21,756,538	22,053,135	22,346,572	22,602,080	22,848,047	23,116,481	23,416,381	23,720,203	24,027,996
Commercial (Sales)	11,359,934	11,207,914	11,360,706	11,511,870	11,643,496	11,770,206	11,908,490	12,062,984	12,219,498	12,378,058
Industrial (Transport & Interruptible)	21,726,837	23,341,322	23,768,266	23,911,467	23,949,115	23,953,518	23,953,518	23,953,518	23,953,518	23,953,518
Power Generation	2,170,187	2,200,000	2,200,000	2,200,000	13,113,500	13,113,500	13,113,500	13,113,500	13,113,500	13,113,500
PNW Annual Demand - Base	**824,450,999**	**825,550,902**	**829,621,137**	**842,536,708**	**862,211,584**	**869,594,739**	**881,693,776**	**890,126,499**	**896,539,234**	**901,170,790**
Residential	224,810,194	225,155,206	227,911,640	230,294,446	233,290,393	235,967,251	238,968,796	241,972,195	245,049,736	248,010,846
Commercial (Sales)	146,324,796	147,376,807	148,504,209	149,757,553	151,353,789	151,185,184	151,967,361	153,599,493	155,359,259	157,118,752
Industrial (Transport & Interruptible)	220,446,427	224,302,239	227,512,820	230,298,237	231,321,633	233,008,433	233,807,806	234,300,859	234,631,237	234,941,895
Power Generation	232,869,582	228,716,651	225,692,469	232,186,472	246,245,769	249,433,870	256,949,813	260,253,952	261,499,003	261,099,296

A3. ANNUAL DEMAND BY REGION AND SECTOR, HIGH CASE

Northwest Gas Association
2009 Natural Gas Outlook
Annual Demand Summary (Dth) - High Case

Region/Sector	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
BC Lower Mainland & Van. Island	**143,915,518**	**143,967,332**	**144,115,649**	**144,293,782**	**144,484,028**	**142,843,600**	**144,002,741**	**144,252,463**	**144,447,210**	**144,649,589**
Residential	53,526,953	53,181,421	52,855,072	52,530,137	52,206,817	51,792,103	52,731,720	52,661,115	52,573,958	52,492,779
Commercial (Sales)	38,905,728	39,320,521	39,762,466	40,209,523	40,667,077	39,355,612	39,660,789	39,963,949	40,245,852	40,529,411
Industrial (Transport & Interruptible)	32,058,370	31,946,142	31,978,863	32,034,874	32,090,886	32,176,638	32,090,984	32,108,151	32,108,151	32,108,151
Power Generation	19,424,467	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248
W. Washington	**281,521,073**	**290,897,678**	**302,884,614**	**332,261,849**	**310,349,778**	**311,431,273**	**313,539,529**	**327,389,894**	**306,258,820**	**311,237,267**
Residential	69,374,429	70,914,146	73,108,022	74,949,916	77,247,105	79,583,778	81,961,627	84,291,587	86,574,009	88,785,595
Commercial (Sales)	42,879,760	43,882,015	43,902,892	44,214,960	44,787,240	45,503,273	46,356,933	47,248,461	48,201,216	49,149,982
Industrial (Transport)	75,446,221	75,202,583	74,961,433	74,846,681	74,807,216	74,843,162	74,918,687	75,011,322	74,976,138	75,076,602
Power Generation	93,820,663	100,898,934	110,912,266	138,250,291	113,508,217	111,501,060	110,302,282	120,838,524	96,507,457	98,225,088
W. Oregon	**121,094,003**	**124,159,905**	**128,454,321**	**132,198,756**	**134,441,286**	**136,632,331**	**139,209,852**	**140,960,319**	**142,793,515**	**144,551,902**
Residential	38,711,067	39,260,318	40,434,186	41,428,025	42,570,627	43,715,930	45,249,521	46,393,312	47,689,500	48,980,378
Commercial (Sales)	24,636,214	24,824,344	25,310,334	25,563,105	25,836,904	26,108,822	26,603,005	26,877,289	27,233,984	27,589,047
Industrial (Transport & Interruptible)	39,175,963	41,825,243	44,459,801	46,957,626	47,783,755	48,557,580	49,107,326	49,439,717	49,620,031	49,732,477
Power Generation	18,570,759	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000
BC Interior	**51,133,665**	**51,077,745**	**51,330,443**	**51,689,651**	**52,058,108**	**52,379,338**	**53,005,711**	**53,153,170**	**53,239,528**	**53,313,480**
Residential	16,463,752	16,312,794	16,387,069	16,544,880	16,707,015	16,629,839	16,938,206	16,939,285	16,897,248	16,845,103
Commercial (Sales)	10,396,100	10,590,560	10,786,954	10,988,351	11,194,673	11,256,239	11,579,308	11,725,688	11,854,084	11,980,180
Industrial (Transport & Interruptible)	24,273,813	24,174,391	24,156,420	24,156,420	24,156,420	24,493,260	24,488,197	24,488,197	24,488,197	24,488,197
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**93,976,306**	**95,300,655**	**102,038,463**	**102,731,913**	**104,507,030**	**106,816,787**	**113,101,588**	**111,593,353**	**113,496,424**	**114,573,116**
Residential	19,304,980	19,280,266	19,523,625	19,876,685	20,300,292	20,743,060	21,120,064	21,478,490	21,886,565	22,317,318
Commercial (Sales)	14,402,914	14,722,153	15,120,815	15,550,951	16,022,761	16,505,138	16,944,676	17,367,159	17,827,735	18,304,332
Industrial (Transport & Interruptible)	29,508,826	29,784,656	30,057,008	30,279,932	30,508,045	30,733,435	30,946,490	31,146,663	31,357,087	31,574,145
Power Generation	30,759,587	31,513,580	37,337,014	37,024,345	37,675,933	38,835,153	44,090,359	41,601,042	42,425,037	42,377,321
E. Oregon & Medford	**124,406,756**	**125,642,481**	**129,701,628**	**132,571,967**	**135,125,211**	**136,321,877**	**138,409,906**	**139,211,786**	**139,370,116**	**136,802,592**
Residential	6,921,074	7,086,952	7,355,252	7,657,352	7,970,504	8,287,894	8,612,115	8,932,204	9,250,101	9,569,779
Commercial (Sales)	5,242,005	5,360,141	5,499,505	5,648,678	5,793,698	5,939,467	6,086,348	6,228,750	6,368,250	6,508,238
Industrial (Transport & Interruptible)	8,868,521	9,026,637	9,216,775	9,305,125	9,371,961	9,400,986	9,424,100	9,445,179	9,468,267	9,490,787
Power Generation	103,375,156	104,168,751	107,630,096	109,960,812	111,989,049	112,693,530	114,287,343	114,605,652	114,283,497	111,233,788
S. Idaho	**61,055,075**	**62,772,760**	**63,726,132**	**64,607,316**	**76,235,645**	**76,988,919**	**77,871,595**	**78,856,344**	**79,726,351**	**80,615,894**
Residential	22,750,588	22,662,484	23,183,536	23,745,793	24,207,680	24,694,942	25,215,002	25,776,596	26,350,801	26,937,899
Commercial (Sales)	11,720,000	11,674,613	11,943,034	12,232,681	12,470,623	12,721,637	12,989,547	13,278,852	13,574,655	13,877,100
Industrial (Transport & Interruptible)	24,414,299	26,235,662	26,399,562	26,428,841	26,443,841	26,458,841	26,553,547	26,687,396	26,687,396	26,687,396
Power Generation	2,170,187	2,200,000	2,200,000	2,200,000	13,113,500	13,113,500	13,113,500	13,113,500	13,113,500	13,113,500
PNW Annual Demand - High	**877,102,395**	**893,818,556**	**922,251,249**	**960,355,235**	**957,201,086**	**963,414,125**	**979,140,923**	**995,417,329**	**979,331,965**	**985,743,840**
Residential	227,052,843	228,698,381	232,846,763	236,732,788	241,210,040	245,447,545	251,828,255	256,472,589	261,222,182	265,928,852
Commercial (Sales)	148,182,720	150,374,347	152,326,000	154,408,249	156,772,976	157,390,188	160,220,605	162,690,148	165,305,777	167,938,289
Industrial (Transport & Interruptible)	233,746,013	238,195,314	241,229,862	244,009,501	245,162,123	246,663,901	247,529,331	248,326,626	248,705,267	249,157,755
Power Generation	268,120,819	276,550,514	295,848,624	325,204,697	314,055,947	313,912,492	319,562,732	327,927,966	304,098,739	302,718,944

Northwest Gas Association
2009 Natural Gas Outlook
Annual Demand Summary (Dth) - Low Case

Region/Sector	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
BC Lower Mainland & Van. Island	**142,610,582**	**142,661,418**	**142,808,103**	**142,984,512**	**143,172,863**	**141,556,805**	**139,939,278**	**140,178,773**	**140,364,955**	**140,558,433**
Residential	52,771,276	52,430,622	52,108,880	51,788,532	51,469,777	51,060,918	50,412,556	50,345,056	50,261,733	50,184,124
Commercial (Sales)	38,356,470	38,765,406	39,201,112	39,641,857	40,092,952	38,800,001	37,916,490	38,206,317	38,475,822	38,746,909
Industrial (Transport & Interruptible)	32,058,370	31,946,142	31,978,863	32,034,874	32,090,886	32,176,638	32,090,984	32,108,151	32,108,151	32,108,151
Power Generation	19,424,467	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248	19,519,248
W. Washington	**254,342,111**	**255,170,887**	**255,531,871**	**269,058,275**	**265,364,564**	**265,533,013**	**266,329,880**	**276,591,305**	**279,803,460**	**278,010,525**
Residential	67,838,543	68,180,654	69,559,130	70,639,216	72,079,101	73,479,818	74,888,215	76,216,192	77,494,943	78,631,046
Commercial (Sales)	41,560,149	41,420,346	40,916,874	40,785,145	40,963,278	41,275,072	41,704,476	42,155,021	42,656,962	43,139,161
Industrial (Transport)	71,893,690	71,321,434	70,913,637	70,843,035	70,712,145	70,674,565	70,683,861	70,653,025	70,715,877	70,729,123
Power Generation	73,049,729	74,248,453	74,142,231	86,790,879	81,610,040	80,103,558	79,053,328	87,567,066	88,935,678	85,511,195
W. Oregon	**117,613,676**	**119,873,003**	**122,857,623**	**125,166,399**	**126,119,699**	**127,025,785**	**128,267,156**	**128,699,637**	**129,222,800**	**129,704,109**
Residential	37,194,220	37,378,916	37,888,858	38,140,779	38,577,294	39,016,778	39,803,427	40,203,176	40,746,308	41,293,653
Commercial (Sales)	23,837,903	23,780,105	23,869,598	23,708,976	23,611,471	23,526,912	23,650,386	23,562,824	23,556,962	23,559,754
Industrial (Transport & Interruptible)	38,010,793	40,463,982	42,849,167	45,066,644	45,680,933	46,232,095	46,563,343	46,683,636	46,669,530	46,600,702
Power Generation	18,570,759	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000
BC Interior	**50,754,466**	**50,697,932**	**50,946,809**	**51,300,946**	**51,664,201**	**51,985,651**	**51,751,499**	**51,892,472**	**51,975,032**	**52,045,732**
Residential	16,231,321	16,082,495	16,155,722	16,311,305	16,471,150	16,395,064	16,193,257	16,194,288	16,154,099	16,104,249
Commercial (Sales)	10,249,331	10,441,046	10,634,667	10,833,221	11,036,630	11,097,327	11,070,045	11,209,987	11,332,736	11,453,286
Industrial (Transport & Interruptible)	24,273,813	24,174,391	24,156,420	24,156,420	24,156,420	24,493,260	24,488,197	24,488,197	24,488,197	24,488,197
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**85,026,554**	**83,031,880**	**79,096,335**	**77,154,076**	**76,456,186**	**76,231,502**	**76,032,224**	**76,589,422**	**76,974,170**	**76,895,612**
Residential	18,942,560	18,782,481	18,038,143	17,305,251	17,145,588	17,071,740	16,945,269	16,805,443	16,702,727	16,614,162
Commercial (Sales)	13,930,689	14,032,059	13,768,754	13,497,732	13,564,453	13,679,452	13,758,438	13,823,368	13,913,616	14,012,671
Industrial (Transport & Interruptible)	28,100,534	28,354,439	28,604,448	28,805,273	29,011,054	29,213,038	29,403,282	29,581,743	29,768,197	29,959,458
Power Generation	24,052,772	21,862,901	18,684,989	17,545,821	16,735,091	16,267,272	15,925,235	16,378,868	16,589,632	16,309,321
E. Oregon & Medford	**111,592,848**	**106,955,971**	**100,754,075**	**98,859,118**	**97,438,497**	**96,127,749**	**95,815,193**	**96,783,066**	**97,293,696**	**96,062,883**
Residential	7,889,659	7,941,827	7,899,821	7,860,548	7,934,555	8,025,091	8,115,155	8,198,468	8,277,653	8,350,061
Commercial (Sales)	5,621,286	5,643,845	5,606,786	5,573,221	5,590,210	5,611,211	5,632,409	5,648,977	5,665,016	5,678,054
Industrial (Transport & Interruptible)	8,201,097	8,351,353	8,531,828	8,610,200	8,668,141	8,688,006	8,701,741	8,713,600	8,726,901	8,739,454
Power Generation	89,880,806	85,018,946	78,715,639	76,815,149	75,245,591	73,803,441	73,365,889	74,222,021	74,624,125	73,295,314
S. Idaho	**54,284,801**	**54,261,201**	**54,313,081**	**54,776,650**	**65,864,533**	**65,943,823**	**66,120,315**	**66,252,601**	**66,378,108**	**66,504,119**
Residential	21,855,901	21,461,582	21,419,681	21,540,480	21,597,015	21,634,651	21,690,474	21,772,973	21,855,807	21,938,975
Commercial (Sales)	11,259,100	11,055,967	11,034,381	11,096,611	11,125,735	11,145,123	11,173,881	11,216,380	11,259,052	11,301,896
Industrial (Transport & Interruptible)	18,999,613	19,543,653	19,659,019	19,939,560	20,028,284	20,050,550	20,142,460	20,149,748	20,149,748	20,149,748
Power Generation	2,170,187	2,200,000	2,200,000	2,200,000	13,113,500	13,113,500	13,113,500	13,113,500	13,113,500	13,113,500
PNW Annual Demand - Low	**816,225,038**	**812,652,291**	**806,307,897**	**819,299,976**	**826,080,542**	**824,404,328**	**824,255,546**	**836,987,276**	**842,012,221**	**839,781,413**
Residential	222,723,480	222,258,578	223,070,235	223,586,111	225,274,480	226,684,059	228,048,352	229,735,596	231,493,270	233,116,270
Commercial (Sales)	144,814,929	145,138,773	145,032,172	145,136,762	145,984,728	145,135,098	144,906,125	145,822,874	146,860,167	147,891,731
Industrial (Transport & Interruptible)	221,537,910	224,155,392	226,693,382	229,456,006	230,347,864	231,528,151	232,073,868	232,378,103	232,626,601	232,774,834
Power Generation	227,148,720	221,099,548	211,512,107	221,121,097	224,473,471	221,057,019	219,227,200	229,050,704	231,032,183	225,998,578

A5. I-5 CORRIDOR PEAK DAY SUPPLY/DEMAND BALANCE – BASE CASE

Northwest Gas Association
2009 Natural Gas Outlook
I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - Base Case

DEMAND (Region/Sector)	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
BC Lower Main & Van. Island (I-5 Corridor)	**1,415,517**	**1,422,444**	**1,428,928**	**1,435,224**	**1,441,329**	**1,447,476**	**1,455,099**	**1,462,388**	**1,469,160**	**1,476,229**
Residential	620,310	624,901	628,386	631,745	634,977	638,248	644,008	648,453	652,657	656,943
Commercial (Firm Sales & Transport)	375,125	377,423	380,389	383,299	386,152	389,005	390,707	393,505	396,064	398,842
Industrial (Firm Sales & Transport)	158,485	158,523	158,556	158,583	158,602	158,625	158,786	158,832	158,842	158,846
Power Generation	261,597	261,597	261,597	261,597	261,597	261,597	261,597	261,597	261,597	261,597
W. Washington (I-5 Corridor)	**2,116,279**	**2,159,862**	**2,228,555**	**2,258,272**	**2,291,633**	**2,326,481**	**2,362,170**	**2,397,640**	**2,433,024**	**2,466,966**
Residential	784,725	794,893	808,697	826,912	847,133	867,816	888,725	909,254	929,406	947,960
Commercial (Firm Sales & Transport)	334,715	342,123	343,452	348,196	354,288	361,399	368,964	376,523	384,221	391,910
Industrial (Firm Sales & Transport)	280,453	280,683	280,694	280,753	280,966	281,050	281,154	281,285	281,419	281,574
Power Generation	716,386	742,163	795,711	802,411	809,246	816,216	823,327	830,579	837,977	845,522
W. Oregon (I-5 Corridor)	**979,754**	**982,105**	**990,923**	**1,000,016**	**1,007,205**	**1,014,214**	**1,026,319**	**1,036,697**	**1,044,444**	**1,053,587**
Residential	546,664	550,405	558,681	567,855	576,046	584,080	595,268	605,819	614,872	624,756
Commercial (Firm Sales & Transport)	292,915	291,533	292,086	291,398	289,506	287,663	287,765	287,602	286,320	285,596
Industrial (Firm Sales & Transport)	53,176	53,166	53,156	53,763	54,653	55,472	56,287	56,276	56,252	56,234
Power Generation	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000
Total Peak (Design) Day Demand	4,511,551	4,564,410	4,648,406	4,693,513	4,740,166	4,788,170	4,843,588	4,896,725	4,946,627	4,996,781
SUPPLY										
Pipeline Interconnects	**2,304,060**	**2,304,061**	**2,304,062**	**2,304,063**	**2,304,064**	**2,304,065**	**2,304,066**	**2,304,067**	**2,304,068**	**2,304,069**
Max north flow on NWP @ Gorge	**551,000**	**551,001**	**551,002**	**551,003**	**551,004**	**551,005**	**551,006**	**551,007**	**551,008**	**551,009**
Huntingdon/Sumas	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**
T-South to Huntingdon	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060
Kingsvale to Huntingdon (via Southern Crossing)	-	-	-	-	-	-	-	-	-	-
Underground Storage	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
(includes deliverability expansion of 312,000 Dth/day in service 2008-09)										
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450
(includes deliverability expansion of 51,310 Dth/day in service 2007-08)										
Peak LNG	**350,338**	**350,338**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (TGI)	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338
Vancouver Island LNG (permitted, provisional)	-	-	154,500	154,500	154,500	154,500	154,500	154,500	154,500	154,500
Total Supply	**4,380,848**	**4,380,849**	**4,535,350**	**4,535,351**	**4,535,352**	**4,535,353**	**4,535,354**	**4,535,355**	**4,535,356**	**4,535,357**
Supply Surplus/**(Shortfall)**	(130,703)	(183,561)	(113,056)	(158,162)	(204,814)	(252,817)	(308,234)	(361,370)	(411,271)	(461,424)

A6. I-5 CORRIDOR PEAK DAY SUPPLY/DEMAND BALANCE – HIGH CASE

Northwest Gas Association
2009 Natural Gas Outlook
I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - High Case

DEMAND (Region/Sector)	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
BC Lower Main & Van. Island (I-5 Corridor)	**1,419,208**	**1,429,687**	**1,439,581**	**1,449,217**	**1,458,587**	**1,467,831**	**1,478,519**	**1,488,884**	**1,498,619**	**1,508,565**
Residential	622,479	629,162	634,653	639,976	645,132	650,243	657,857	664,145	670,132	676,149
Commercial (Firm Sales & Transport)	376,463	380,046	384,250	388,376	392,419	396,404	399,194	403,108	406,741	410,567
Industrial (Firm Sales & Transport)	158,668	158,881	159,081	159,268	159,438	159,587	159,870	160,034	160,149	160,252
Power Generation	261,597	261,597	261,597	261,597	261,597	261,597	261,597	261,597	261,597	261,597
W. Washington (I-5 Corridor)	**2,137,593**	**2,205,741**	**2,283,478**	**2,321,125**	**2,362,989**	**2,406,863**	**2,452,008**	**2,544,311**	**2,589,538**	**2,633,965**
Residential	791,449	809,721	830,079	853,559	879,528	906,398	933,797	960,920	987,713	1,013,420
Commercial (Firm Sales & Transport)	337,309	346,517	349,888	356,762	365,066	374,472	384,450	394,527	404,852	415,280
Industrial (Firm Sales & Transport)	290,449	290,919	291,049	291,307	291,722	292,001	292,303	292,633	292,974	293,343
Power Generation	718,386	758,585	812,462	819,497	826,673	833,992	841,458	896,231	903,999	911,921
W. Oregon (I-5 Corridor)	**1,005,489**	**1,011,509**	**1,027,651**	**1,045,039**	**1,060,577**	**1,075,722**	**1,096,664**	**1,115,637**	**1,131,520**	**1,148,784**
Residential	561,023	567,058	580,066	594,706	608,536	622,153	639,460	656,046	670,892	686,566
Commercial (Firm Sales & Transport)	298,991	298,900	301,881	303,829	304,438	304,928	307,523	309,723	310,598	312,025
Industrial (Firm Sales & Transport)	58,475	58,551	58,704	59,504	60,604	61,640	62,682	62,868	63,030	63,193
Power Generation	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000
Total Peak (Design) Day Demand	**4,562,290**	**4,646,937**	**4,750,709**	**4,815,381**	**4,882,153**	**4,950,416**	**5,027,191**	**5,148,832**	**5,219,677**	**5,291,313**
SUPPLY										
Pipeline Interconnects	**2,304,060**	**2,304,062**	**2,304,064**	**2,304,066**	**2,304,068**	**2,304,070**	**2,304,072**	**2,304,074**	**2,304,076**	**2,304,078**
Max north flow on NWP @ Gorge	**551,000**	**551,001**	**551,002**	**551,003**	**551,004**	**551,005**	**551,006**	**551,007**	**551,008**	**551,009**
Huntingdon/Sumas	**1,753,060**	**1,753,061**	**1,753,062**	**1,753,063**	**1,753,064**	**1,753,065**	**1,753,066**	**1,753,067**	**1,753,068**	**1,753,069**
T-South to Huntingdon	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060
Kingsvale to Huntingdon (via Southern Crossing)	0	1	2	3	4	5	6	7	8	9
Underground Storage	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
(includes deliverability expansion of 312,000 Dth/day in service 2008-09)										
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450
(includes deliverability expansion of 51,310 Dth/day in service 2007-08)										
Peak LNG	**350,338**	**350,338**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (TGI)	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338
Vancouver Island LNG (permitted, provisional)	-	-	154,500	154,500	154,500	154,500	154,500	154,500	154,500	154,500
Total Supply	**4,380,848**	**4,380,850**	**4,535,352**	**4,535,354**	**4,535,356**	**4,535,358**	**4,535,360**	**4,535,362**	**4,535,364**	**4,535,366**
Supply Surplus/**(Shortfall)**	(181,442)	**(266,087)**	(215,357)	(280,027)	(346,797)	(415,058)	(491,831)	(613,470)	(684,313)	(755,947)

A7. I-5 CORRIDOR PEAK DAY SUPPLY/DEMAND BALANCE – LOW CASE

Northwest Gas Association
2009 Natural Gas Outlook
I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - Low Case

DEMAND (Region/Sector)	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
BC Lower Main & Van. Island (I-5 Corridor)	**1,412,191**	**1,415,949**	**1,419,350**	**1,422,623**	**1,425,716**	**1,428,809**	**1,433,406**	**1,437,712**	**1,441,514**	**1,445,614**
Residential	618,355	621,078	622,749	624,327	625,782	627,261	631,215	633,892	636,330	638,850
Commercial (Firm Sales & Transport)	373,919	375,071	376,917	378,728	380,483	382,221	382,848	384,568	386,054	387,757
Industrial (Firm Sales & Transport)	158,319	158,202	158,086	157,971	157,854	157,729	157,745	157,654	157,532	157,410
Power Generation	261,597	261,597	261,597	261,597	261,597	261,597	261,597	261,597	261,597	261,597
W. Washington (I-5 Corridor)	**2,027,544**	**2,068,713**	**2,130,828**	**2,154,826**	**2,181,160**	**2,208,336**	**2,236,111**	**2,310,468**	**2,337,466**	**2,362,987**
Residential	778,909	781,066	790,907	806,284	822,484	838,575	854,723	870,244	885,329	898,858
Commercial (Firm Sales & Transport)	333,015	338,754	338,220	340,953	344,919	349,817	355,092	360,267	365,527	370,701
Industrial (Firm Sales & Transport)	271,147	270,965	270,553	270,076	269,751	269,317	268,914	268,526	268,152	267,802
Power Generation	644,473	677,928	731,148	737,513	744,005	750,628	757,383	811,431	818,458	825,626
W. Oregon (I-5 Corridor)	**932,758**	**930,363**	**931,952**	**932,731**	**932,532**	**932,774**	**938,262**	**941,462**	**942,431**	**944,750**
Residential	543,455	544,190	547,839	551,542	554,774	558,191	564,830	570,387	574,650	579,666
Commercial (Firm Sales & Transport)	291,251	288,258	286,345	282,981	278,843	275,036	273,266	271,085	267,971	265,442
Industrial (Firm Sales & Transport)	48,052	47,916	47,768	48,208	48,915	49,547	50,166	49,991	49,811	49,642
Power Generation	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Total Peak (Design) Day Demand	**4,372,493**	**4,415,026**	**4,482,130**	**4,510,181**	**4,539,409**	**4,569,918**	**4,607,779**	**4,689,642**	**4,721,411**	**4,753,351**
SUPPLY										
Pipeline Interconnects	**2,304,060**	**2,304,061**	**2,304,062**	**2,304,063**	**2,304,064**	**2,304,065**	**2,304,066**	**2,304,067**	**2,304,068**	**2,304,069**
Max north flow on NWP @ Gorge	**551,000**	**551,001**	**551,002**	**551,003**	**551,004**	**551,005**	**551,006**	**551,007**	**551,008**	**551,009**
Huntingdon/Sumas	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**
T-South to Huntingdon	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060
Kingsvale to Huntingdon (via Southern Crossing)	-	-	-	-	-	-	-	-	-	-
Underground Storage	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
(includes deliverability expansion of 312,000 Dth/day in service 2008-09)										
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450
(includes deliverability expansion of 51,310 Dth/day in service 2007-08)										
Peak LNG	**350,338**	**350,338**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**	**504,838**
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (TGI)	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338	157,338
Vancouver Island LNG (permitted, provisional)	-	-	154,500	154,500	154,500	154,500	154,500	154,500	154,500	154,500
Total Supply	**4,380,848**	**4,380,849**	**4,535,350**	**4,535,351**	**4,535,352**	**4,535,353**	**4,535,354**	**4,535,355**	**4,535,356**	**4,535,357**
Supply Surplus/**(Shortfall)**	8,355	(34,177)	53,220	25,170	(4,057)	(34,565)	(72,425)	(154,287)	(186,055)	(217,994)

Northwest Gas Association
2009 Natural Gas Outlook
NON I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - Base Case

DEMAND (Region/Sector)	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
BC Interior	**434,720**	**438,231**	**441,716**	**445,143**	**448,510**	**451,746**	**455,380**	**459,290**	**462,321**	**465,182**
Residential	208,939	211,030	213,100	215,126	217,109	219,006	221,324	223,545	225,169	226,677
Commercial (Sales)	115,011	116,428	117,843	119,244	120,630	121,973	123,254	124,945	126,353	127,707
Industrial (Transport & Interruptible)	110,770	110,773	110,774	110,773	110,771	110,768	110,802	110,800	110,799	110,797
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**686,186**	**685,084**	**690,725**	**696,649**	**702,597**	**708,575**	**708,748**	**714,555**	**720,580**	**726,613**
Residential	203,380	200,976	203,192	205,615	208,001	210,400	209,156	211,469	213,864	216,265
Commercial (Sales)	145,955	147,324	150,711	154,154	157,633	161,119	162,446	165,875	169,392	172,906
Industrial (Transport & Interruptible)	94,813	94,746	94,784	94,842	94,924	95,018	95,108	95,172	95,286	95,405
Power Generation	242,038	242,038	242,038	242,038	242,038	242,038	242,038	242,038	242,038	242,038
E. Oregon & Medford	**603,858**	**607,163**	**612,063**	**617,676**	**623,392**	**629,119**	**633,730**	**639,543**	**645,353**	**651,160**
Residential	89,224	90,178	92,185	94,777	97,488	100,204	102,162	104,916	107,617	110,278
Commercial (Sales)	57,662	58,255	59,298	60,422	61,484	62,508	63,132	64,138	65,129	66,118
Industrial (Transport & Interruptible)	44,025	43,984	43,997	44,021	44,054	44,093	44,134	44,161	44,210	44,259
Power Generation	412,947	414,747	416,583	418,456	420,366	422,314	424,301	426,329	428,396	430,505
S. Idaho	**536,316**	**541,623**	**553,458**	**558,952**	**593,360**	**597,768**	**604,382**	**611,105**	**617,938**	**624,884**
Residential	245,211	248,713	256,525	260,150	263,060	265,969	270,334	274,771	279,281	283,865
Commercial (Sales)	126,321	128,125	132,149	134,017	135,516	137,014	139,263	141,549	143,872	146,234
Industrial (Transport & Interruptible)	91,216	91,216	91,216	91,216	91,216	91,216	91,216	91,216	91,216	91,216
Power Generation	73,569	73,569	73,569	73,569	103,569	103,569	103,569	103,569	103,569	103,569
Total Peak (Design) Day Demand	**2,261,080**	**2,272,101**	**2,297,963**	**2,318,420**	**2,367,858**	**2,387,208**	**2,402,240**	**2,424,492**	**2,446,192**	**2,467,839**
SUPPLY										
Pipeline Interconnects	**1,594,830**	**1,594,829**	**1,594,828**	**1,594,827**	**1,594,826**	**1,594,825**	**1,594,824**	**1,594,823**	**1,594,822**	**1,594,821**
NWP- Stanfield (NWP from GTN)	638,000	638,000	638,000	638,000	638,000	638,000	638,000	638,000	638,000	638,000
NWP - Starr Rd (NWP from GTN)	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000
NWP - Palouse (NWP from GTN)	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
GTN - Direct Connects	415,000	415,000	415,000	415,000	415,000	415,000	415,000	415,000	415,000	415,000
Kingsgate/Yahk - BC Interior from TCPL	182,625	182,625	182,625	182,625	182,625	182,625	182,625	182,625	182,625	182,625
Westcoast to BC Interior	178,705	178,705	178,705	178,705	178,705	178,705	178,705	178,705	178,705	178,705
Westcoast to Kingsvale	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500
NWP - Kemmerer (NWP north from NWP south)	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000
NWP - Kemmerer to Reno	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)
Peak LNG	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**
Plymouth (NWP from LNG)	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300
Nampa LNG (IGC)	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Total Supply	**1,960,130**	**1,960,129**	**1,960,128**	**1,960,127**	**1,960,126**	**1,960,125**	**1,960,124**	**1,960,123**	**1,960,122**	**1,960,121**
Supply Surplus/**(Shortfall)**	(300,950)	(311,972)	(337,835)	(358,293)	(407,732)	(427,083)	(442,116)	(464,369)	(486,070)	(507,718)

Northwest Gas Association

2009 Natural Gas Outlook

NON I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - High Case

DEMAND (Region/Sector)	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
BC Interior	**436,088**	**440,903**	**445,667**	**450,353**	**454,959**	**459,367**	**464,112**	**469,225**	**473,294**	**477,025**
Residential	209,812	212,733	215,617	218,443	221,212	223,851	226,875	229,854	232,128	234,178
Commercial (Sales)	115,491	117,368	119,235	121,083	122,910	124,671	126,346	128,471	130,258	131,933
Industrial (Transport & Interruptible)	110,785	110,801	110,815	110,827	110,837	110,845	110,891	110,900	110,908	110,915
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**700,736**	**704,007**	**714,420**	**725,217**	**736,104**	**747,047**	**756,586**	**767,558**	**778,917**	**790,358**
Residential	207,510	207,317	212,227	217,439	222,669	227,930	232,295	237,583	243,030	248,516
Commercial (Sales)	150,685	154,108	159,470	164,895	170,362	175,848	180,812	186,325	192,009	197,719
Industrial (Transport & Interruptible)	100,503	100,543	100,685	100,846	101,036	101,232	101,441	101,613	101,841	102,085
Power Generation	242,038	242,038	242,038	242,038	242,038	242,038	242,038	242,038	242,038	242,038
E. Oregon & Medford	**588,532**	**598,171**	**604,545**	**611,955**	**619,432**	**627,045**	**634,729**	**642,592**	**650,563**	**658,574**
Residential	76,548	78,499	81,241	84,900	88,633	92,445	96,250	100,198	104,163	108,157
Commercial (Sales)	52,946	54,237	55,878	57,590	59,246	60,913	62,612	64,321	66,051	67,747
Industrial (Transport & Interruptible)	46,091	46,098	46,161	46,234	46,316	46,405	46,498	46,576	46,681	46,787
Power Generation	412,947	419,337	421,265	423,231	425,237	427,282	429,369	431,498	433,669	435,883
S. Idaho	**540,464**	**549,847**	**565,850**	**576,806**	**619,970**	**628,118**	**638,724**	**649,594**	**660,734**	**672,152**
Residential	246,121	252,314	262,876	270,107	275,495	280,873	287,873	295,047	302,400	309,935
Commercial (Sales)	126,790	129,980	135,421	139,146	141,922	144,692	148,298	151,994	155,782	159,664
Industrial (Transport & Interruptible)	93,984	93,984	93,984	93,984	93,984	93,984	93,984	93,984	93,984	93,984
Power Generation	73,569	73,569	73,569	73,569	108,569	108,569	108,569	108,569	108,569	108,569
Total Peak (Design) Day Demand	**2,265,820**	**2,292,928**	**2,330,482**	**2,364,331**	**2,430,465**	**2,461,578**	**2,494,152**	**2,528,969**	**2,563,509**	**2,598,109**
SUPPLY										
Pipeline Interconnects	**1,594,830**	**1,594,829**	**1,594,828**	**1,594,827**	**1,594,826**	**1,594,825**	**1,594,824**	**1,594,823**	**1,594,822**	**1,594,821**
NWP- Stanfield (NWP from GTN)	638,000	638,000	638,000	638,000	638,000	638,000	638,000	638,000	638,000	638,000
NWP - Starr Rd (NWP from GTN)	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000
NWP - Palouse (NWP from GTN)	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
GTN - Direct Connects	415,000	415,000	415,000	415,000	415,000	415,000	415,000	415,000	415,000	415,000
Kingsgate/Yahk - BC Interior from TCPL	182,625	182,625	182,625	182,625	182,625	182,625	182,625	182,625	182,625	182,625
Westcoast to BC Interior	178,705	178,705	178,705	178,705	178,705	178,705	178,705	178,705	178,705	178,705
Westcoast to Kingsvale	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500
NWP - Kemmerer (NWP north from NWP south)	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000
NWP - Kemmerer to Reno	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)
Peak LNG	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**
Plymouth (NWP from LNG)	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300
Nampa LNG (IGC)	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Total Supply	**1,960,130**	**1,960,129**	**1,960,128**	**1,960,127**	**1,960,126**	**1,960,125**	**1,960,124**	**1,960,123**	**1,960,122**	**1,960,121**
Supply Surplus/**(Shortfall)**	(305,690)	(332,799)	(370,354)	(404,204)	(470,339)	(501,453)	(534,028)	(568,846)	(603,387)	(637,988)

Northwest Gas Association
2009 Natural Gas Outlook
NON I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - Low Case

DEMAND (Region/Sector)	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
BC Interior	**433,537**	**435,987**	**438,446**	**440,859**	**443,228**	**445,462**	**448,148**	**451,066**	**453,336**	**455,547**
Residential	208,184	209,599	211,016	212,398	213,748	215,011	216,726	218,323	219,471	220,576
Commercial (Sales)	114,595	115,639	116,690	117,732	118,763	119,748	120,694	122,026	123,156	124,270
Industrial (Transport & Interruptible)	110,757	110,749	110,739	110,729	110,717	110,703	110,728	110,717	110,709	110,702
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**680,595**	**680,764**	**670,175**	**658,260**	**657,923**	**658,853**	**656,766**	**656,943**	**657,586**	**657,695**
Residential	202,823	201,690	193,964	185,424	184,087	183,550	181,112	180,123	179,389	178,321
Commercial (Sales)	145,098	146,551	143,761	140,446	141,465	142,944	143,303	144,506	145,879	147,048
Industrial (Transport & Interruptible)	90,637	90,485	90,412	90,352	90,334	90,321	90,312	90,276	90,280	90,288
Power Generation	242,038	242,038	242,038	242,038	242,038	242,038	242,038	242,038	242,038	242,038
E. Oregon & Medford	**595,027**	**597,852**	**598,574**	**599,368**	**601,986**	**605,471**	**608,464**	**611,851**	**615,298**	**618,652**
Residential	87,842	88,685	88,116	87,631	88,350	89,630	90,564	91,746	92,928	94,013
Commercial (Sales)	56,752	57,107	56,682	56,204	56,301	56,665	56,843	57,143	57,444	57,710
Industrial (Transport & Interruptible)	41,987	41,904	41,875	41,854	41,840	41,830	41,823	41,803	41,802	41,801
Power Generation	408,447	410,157	411,901	413,680	415,495	417,346	419,234	421,159	423,124	425,127
S. Idaho	**472,538**	**474,468**	**482,392**	**484,798**	**505,580**	**506,998**	**510,467**	**513,968**	**517,499**	**521,063**
Residential	244,615	245,888	251,118	252,706	253,222	254,158	256,448	258,758	261,089	263,441
Commercial (Sales)	126,014	126,670	129,364	130,182	130,448	130,930	132,109	133,299	134,500	135,712
Industrial (Transport & Interruptible)	85,470	85,470	85,470	85,470	85,470	85,470	85,470	85,470	85,470	85,470
Power Generation	16,440	16,440	16,440	16,440	36,440	36,440	36,440	36,440	36,440	36,440
Total Peak (Design) Day Demand	**2,181,697**	**2,189,071**	**2,189,586**	**2,183,286**	**2,208,717**	**2,216,784**	**2,223,845**	**2,233,828**	**2,243,719**	**2,252,957**
SUPPLY										
Pipeline Interconnects	**1,594,830**	**1,594,829**	**1,594,828**	**1,594,827**	**1,594,826**	**1,594,825**	**1,594,824**	**1,594,823**	**1,594,822**	**1,594,821**
NWP- Stanfield (NWP from GTN)	638,000	638,000	638,000	638,000	638,000	638,000	638,000	638,000	638,000	638,000
NWP - Starr Rd (NWP from GTN)	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000
NWP - Palouse (NWP from GTN)	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
GTN - Direct Connects	415,000	415,000	415,000	415,000	415,000	415,000	415,000	415,000	415,000	415,000
Kingsgate/Yahk - BC Interior from TCPL	182,625	182,625	182,625	182,625	182,625	182,625	182,625	182,625	182,625	182,625
Westcoast to BC Interior	178,705	178,705	178,705	178,705	178,705	178,705	178,705	178,705	178,705	178,705
Westcoast to Kingsvale	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500
NWP - Kemmerer (NWP north from NWP south)	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000
NWP - Kemmerer to Reno	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)
Peak LNG	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**	**365,300**
Plymouth (NWP from LNG)	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300
Nampa LNG (IGC)	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Total Supply	**1,960,130**	**1,960,129**	**1,960,128**	**1,960,127**	**1,960,126**	**1,960,125**	**1,960,124**	**1,960,123**	**1,960,122**	**1,960,121**
Supply Surplus/**(Shortfall)**	(221,567)	(228,942)	(229,458)	(223,159)	(248,591)	(256,659)	(263,721)	(273,705)	(283,597)	(292,836)

Appendix B
MARKET TRENDS AND ENERGY FORECAST

SAMPSON RESEARCH

Consulting Project

2008 Residential End Use Study

Final Report

Prepared for:

Terasen Gas Inc.

Prepared by:

Sampson Research Inc.

With:

Habart & Associates Consulting Inc.
NRG Research Group
InterVISTAS Consulting Inc.
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Disclaimer

The opinions expressed in this report are the responsibility of the author, Sampson Research, and do not necessarily represent the views of Terasen Gas.

Currency Units

All dollar figures presented in this report, unless stated otherwise, are expressed in Canadian funds.

Acknowledgements

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2008 Residential End Use Study

Executive Summary

Introduction & Background

The 2008 Residential End Use Study (REUS) analyzes information on energy end uses and behaviours from a joint mail and Internet survey of over 2,200 Terasen Gas residential customers implemented in November 2008. Information from this survey was compared and contrasted with that collected from similar residential end use studies conducted in 2002 and 1993 by BC Gas. Data from the 2008 REUS are presented by region (Lower Mainland, Vancouver Island, Interior, Whistler, Fort Nelson, TG, and TGI), and dwelling type (single family detached, vertical subdivisions, and other multifamily). Comparisons with 2002 and 1993 data are made using the TGI group of customers to be consistent with the earlier studies.

Study objectives for the 2008 REUS included determining changes in the penetration and saturation rates for various gas (piped gas or propane) end uses, and examining trends in building type, appliance efficiency, renovations, and socio-demographic characteristics of TG customers that may be contributing to the decline in natural gas use rates. A conditional demand analysis (CDA) was conducted to estimate consumption estimates for a variety of gas end uses.

The 2008 REUS includes two additional analyses that are published separately from this document:

- End Use Discrepancy Analysis (EUDA) – an analysis of the factors that explain the differences in energy consumption between gas heated and electrically heated homes.
- Market Segmentation Analysis – the determination of customer groupings (segments) within Terasen's residential customer base, based on a pairings of socio-demographic characteristics, behaviours, and attitudes.

The 2008 REUS report is a resource for Terasen Gas management and staff. It summarizes the survey data and identifies key trends specifically to meet the needs of Terasen's forecasting, program planning, marketing, and communication functions. While the amount of data and information presented in this report is extensive, there may be additional analyses or relationships within the data that are of interest to Terasen. Electronic copies of the both the survey dataset and data cross-tabulations have been provided to Terasen to allow staff to conduct their own explorations and investigations of the data.

Study Highlights

The following represent highlights from the 2008 REUS. Considerably more information is available in the main body of the report, including data by the five regions, three building types, and, where possible, comparisons with the results from the 2002 and 1993 studies.

Trend Analysis

Declines in weather normalized use rates (i.e., gas consumption per household) have been experienced in four of the five Terasen Gas (TG) regions between 1999 and 2008. Overall, TG use rates are down 15.5% since 2002 and 20.7% since 1999. Whistler was the only region experiencing an increase in its residential use rate since 2002 (+6.4%).

Declines in natural gas use rates are primarily attributed to the following factors and trends:

- Construction of smaller, less energy-intensive multifamily dwellings including townhouses, and apartments.

- Improvements in the thermal envelope of homes (improved insulation, energy efficient windows, etc.).
- Improvements in the efficiency of gas end uses including furnaces, water heaters, and fireplaces.
- Improvements in the efficiency of hot water-using appliances, including front loading clothes washers, and dishwashers.
- The long-term decline in the average number of people per-household.
- Reduced hot water demand stemming from the aging of the population and proportionately fewer households with young families.
- Increases in the price of natural gas. The inflation-adjusted variable rate portion of natural gas prices in the Lower Mainland region, for example, increased by 10% between January 2002 and December 2002, and 78% since January 1999.

Trends countering the decline in use rates include:

- Increased space heating requirements of newer single family detached homes due to increased interior volumes (increased ceiling height and increased floor area).

Building Envelope & Renovations

- Eighty-three percent (83%) of respondents to the 2008 REUS live in single family detached (SFD) dwellings, 13% in duplexes or townhouses, 1% in apartments or condominiums, and 3% in mobile homes or other dwelling type.
- Individually metered suites within a multi-storey building, also described as vertical sub-divisions (VSDs), are home to higher proportion of younger residents (under the age of 44) compared to SFDs and other multifamily dwellings (MFDs).
- The average length of residence (years living in the same premise) is increasing, presently 15 years, up from 10 years in 1993. The frequency of changes in residence decreases as people age.
- Average size (floor space) varies by building type and dwelling vintage. SFDs averaged 2,263 ft^2, compared to 1,672 ft^2 for MFDs, and 1,291 ft^2 for VSDs. SFDs built after 1985 tend to be larger (up to 24% larger), on average, that those built earlier.
- The incidence of partially or completely finished basements is increasing, up from 62% in 1993 to 68% in 2008.
- Nearly three quarters (74%) of basements and crawlspaces are heated during the winter season.
- Homes built after 1985 are increasingly likely to have nine or ten foot ceilings, compared to the traditional eight foot ceiling of homes of older homes. VSDs are more likely than SFDs and MFDs to have nine or ten foot ceilings (average of 60% versus 23% and 35% respectively). The majority (81%) of VSDs were built since 1995.
- Consistent with trends in housing construction and changes in building codes, newer homes are more likely to have average or above average insulation, high efficiency windows, and insulated outside doors.

Renovation Activities – Past and Planned

- The top three renovations undertaken in the last five years include purchasing energy efficient appliances (37% of TG customers), installing weather stripping or caulking (21%), and installing a low flow showerhead (19%). These are also the top three activities expected to be occur during the next two years. A comparison of stated intentions from the 2002 REUS with renovations undertaken during the past five years by 2008 REUS respondents suggests that, with a few exceptions, stated intentions are a good predictor of future actions.

- Eleven percent (11%) of TG customers made changes involving fireplaces or heating stoves during the last five years, and 8% plan to undertake similar renovations in the next two years.

Space Heating

- Nine-in-every-ten Terasen Gas customers use natural gas as their primary space heating fuel; a proportion that has remained stable since 1993.
- Fifty-six percent (56%) of TG customers use a supplementary fuel to heat their home. Electricity is the predominant supplementary space heating fuel, used by 67% of these customers. Wood is the second most common supplementary space heating fuel (14%).
- Compared to 2002, the use of electricity as a supplementary space heating fuel has increased from 58% to 73% of TGI households that use supplementary space heating fuel.
- Three percent (3%) of TG customers switched their main space heating fuel in the last five years, with a net shift being from natural gas to electricity. This shift is most evident in the LM, INT and TGVI regions.
- Regardless of main heating method, gas fireplaces are the most commonly used secondary method of heating among TG customers (29% of TG customers). Wired-in and portable electric heaters are the second and third most common methods (11% and 10% respectively).
- VSDs are significantly more likely than SFDs or MFDs to use a gas fireplace as either the main or secondary heating method.
- INT and FN customers are significantly more likely than households in other regions to use a wood stove as their secondary heating method.
- On average, 22% of TG customers have installed a new gas furnace or boiler in the last five years, primarily because of equipment failure (anticipated or actual). High efficiency furnaces were chosen by 40% of those installing a furnace.
- Seventy-three percent (73%) of TG customers with a standard efficiency furnace leave their furnace's pilot light on for 12 months of the year.

Fireplaces and Heating Stoves

- Eighty-five percent (85%) of TG customers have at least one fireplace and/or free standing heating stove.
- The top three most popular fireplace types are heater type gas fireplaces (50% of TG customers), wood burning fireplaces (28%), and decorative gas fireplaces (22%).
- Penetration of fireplaces and heating stoves is highest in TGW (98% of customers) and TGVI (90%), and lowest in the FN region (47%).
- Twenty-eight percent (28%) of respondents with a gas fireplace that uses a pilot light, never turn off the pilot light.
- Fireplace operating hours are highest in the FN and TGVI regions (766 and 702 hours per year, respectively), and lowest in the LM region (393 hours). Average wintertime usage by region is correlated with the regional climate (e.g., number of heating degree days).

- Average annual use of fireplaces and heating stoves is significantly higher for VSDs (697 hours per year) than SFDs (459 hours) and MFDs (387 hours). This is consistent with the greater tendency of customers living in VSDs to use their fireplace as either a primary or secondary space heating method.

Water Heating

- The penetration rate of gas-fired hot water tanks among TG customers is 89%, up from 85% in 2002.
- Whistler households are significantly more likely than any other region to have two or more hot water heaters. This is consistent with the high incidence of secondary suites in the resort community.
- Storage-type hot water tanks (any fuel) continue to make up the vast majority of hot water heaters. One percent (1%) of TG customers have condensing style hot water heaters and 3% have an instantaneous hot water heater.
- Thirty-eight percent (38%) of TG customers have replaced their hot water heater during the last five years. This is on par with the findings from the 2002 REUS.
- The penetration of hot water heater blankets is 6% of households, down from 15% in 2002. Improvements in the tank wall insulation of new hot water heaters has reduced the cost-effectiveness of hot water heater blankets.
- Eighty-one percent (81%) of TG customers use either piped gas or propane for both their main space heating fuel and their water heating fuel.
- Only one percent (1%) of respondents use solar energy to pre-warm or supplement water heating.

Appliances

- The penetration of gas ranges has increased from 9% of TGI households in 1993, to 17% of households in 2008.
- Front loading clothes washers have increased their penetration from 9% of TGI households in 2002 to 27% in 2008, largely at the expense of the lesser-efficient top-loading models.
- The proportion of home appliances rated Energy Star varies from a low of 2% for air conditioners to a high of 53% for refrigerators.

Pools and Hot Tubs

- Six percent (6%) of TG households have a swimming pool that is for their exclusive use only (i.e., not shared with other residences, as is the case in multifamily complexes).
- Forty-three percent (43%) of swimming pools are heated with natural gas. The next most commonly used fuels are solar (15%) and electricity (5%). Thirty-six percent (36%) of pools are not heated.
- Thirteen percent (13%) of TG households have an exclusive use only hot tub.
- Electricity is the predominant fuel used to heat hot tubs (83% of all households with an exclusive use hot tub). Only 15% of households with a hot tub use piped gas or propane to heat the water.
- Ninety-five percent (95%) of hot tub owners use a hot tub cover. Sixty-nine percent (69%) of pool owners use a pool cover.

Behaviours

- Fifty-five percent (55%) of TG customers use at least one programmable thermostat to control temperature in their home.
- Eighty-three percent (83%) of customers with thermostats (programmable or otherwise) always or usually set back the temperature at night, and 70% of them so during the day when no one is at home.
- Customers in electrically heated homes are more likely than those in gas heated homes to keep unoccupied parts of the house cooler than the rest of the home (77% versus 64%, respectively). Customers living in VSDs have a lower share of their rooms that are always heated than do those living in SFDs (52% versus 79% respectively).
- Forty-one percent (41%) of respondents said their home is either always or somewhat drafty. Efforts at draft proofing were unsuccessful for 26% of respondents.
- The use of window coverings (storm windows or plastic sheeting) is highest in the FN region, and is more common among rental properties and homes with single pane windows.
- The number of showers, laundry loads, dishwashing loads, and baths decrease as the number of people in the home decrease. A household that decreases in size from four members to two (e.g., the typical situation when grown-up children leave home) will see, on average, a 36% decline in the number of dishwasher loads, a 43% decline in the number of laundry loads, a 30% decline in the number of baths, and a 53% drop in the number of showers.
- Thirty percent (30%) of respondents, on average, turn down, turn off, or use the vacation setting on their hot water heater when away from home for more than a few days.
- On average, 58% of laundry is washed using cold water.

Programs and Services

- Eleven percent (11%) of respondents have participated in a program to reduce energy use in the last five years, with the program sponsored by either Terasen, a government agency, or some other organization or company.
- Interest was highest for a furnace tune-up program, home energy audits, and a do-it-yourself online energy audit.
- Eighty-five percent (85%) of TG customers claimed they were at least somewhat knowledgeable about ways to save energy. Only 13% categorized themselves as very knowledgeable.
- Seventy-eight percent (78%) of respondents to the 2008 REUS agreed that natural gas is a clean and efficient energy source, unchanged from the 2002 REUS.
- Seventy-four percent (74%) agreed with the statement "natural gas is a safe energy source". Regional results did not differ significantly with the exception of INT residents who were somewhat more in agreement with the statement than residents in the other regions.

Conditional Demand Analysis

A conditional demand analysis (CDA) was conducted using data from the 2008 REUS, billing records, and regional weather stations to estimate unit energy consumption (UEC) estimates for each of the major gas end uses including main and secondary space heating, water heaters, fireplaces, cook tops, pools, hot tubs, and barbeques. Estimates were generated for the five TG regions and TGI. Highlights include:

- Primary and secondary space heating are the two largest gas end uses, consuming 58 GJ/year and 23 GJ/year, respectively.

- Other major gas end uses are water heating (20 GJ/year), decorative fireplaces (21 GJ/year), and heater type fireplaces (17 GJ/year).
- Consistent with their tendency towards smaller household sizes (i.e., number of people per home), UECs for gas water heating for VSDs and MFDs are lower than SFDs.

* * * * * *

1 INTRODUCTION

Terasen Gas Inc. is the largest distributor of natural gas in British Columbia. Its distribution business serves over 900,000 residential, commercial and industrial customers in more than 100 communities.

Terasen engaged the consultant to conduct an end use survey of its residential customers. The primary purpose of the survey was to understand how its residential customers use energy in their homes. This information is of particular importance to Terasen for purposes of:

- forecasting future natural gas demand;
- designing demand-side management programs, and
- assisting the development other marketing and communications programs.

Two REUS studies have been conducted by BC Gas, one in 1993 and the most recent in 2002, that use similar variables to that of the 2008 study. It was an overarching desire of Terasen Gas to be able to compare the findings, and associated analyses, from the 2008 survey with these two earlier studies. As the 1993 survey was considerably shorter than the 2002 and 2008 surveys, comparisons with 1993 data were not always possible.

1.1 Study Objectives

The 2008 Terasen Gas Residential End Use Study was designed to satisfy the following objectives:

- Estimate residential end use saturation and penetration for all natural gas end use appliances.
- Determine primary and secondary energy sources for heating.
- Determine building envelope characteristics that impact the energy efficiency of the home, including recent renovations and/or planned renovations.
- Assess the degree of energy conserving behaviour.
- Perform conditional demand modelling and analysis to develop UECs specific to each of the five regions, and explore differences in UECs between the three building types for LM, INT and TGVI.
- Assess and explain any changes in UEC and saturation rates by appliance from previous REUS surveys.
- Compare findings with previous surveys, where applicable, to assess market changes and trends.
- Analyze trends in housing type, appliance efficiency levels, renovations and demographic shifts.
- Perform customer surveys and analysis to explain the apparent inconsistency in the energy consumption between gas and non-gas heated homes that was detailed in Section 2.4.3 of the BC Hydro Conservation Potential Review. This is referred to as the Energy Use Discrepancy Analysis (EUDA).
- Update the customer segmentation analysis completed as part of the 2002 REUS using data from the 2008 survey.

1.2 Report Organization

This report is organized into 13 sections. Following this introduction, the Background and Methodology section addresses survey sample design, questionnaire design, comparisons to past REUS surveys. Section 3 addresses trends affecting the long-run trend in use rates. The next nine sections address key findings from 2008 REUS survey, organized by the respective topic areas of the survey instrument. Topic areas addressed are:

- Building Envelope and Renovations
- Space Heating
- Fireplaces and Heating Stoves

- Domestic Hot Water
- Appliances
- Pools and Hot Tubs
- Programs and Services
- Behaviours
- Demographics

A presentation of the conditional demand analysis findings, including regional and building type specific UEC estimates, is provided in Section 13.

This document is accompanied with two appendices. Appendix A includes a copy of the 2008 REUS survey instrument and reminder card. Appendix B presents the methodology and model results for the conditional demand analysis.

Two documents, based on the 2008 REUS analysis, are separate from this report. These are:

- End Use Discrepancy Analysis (EUDA) – an analysis of the factors that explain the differences in energy consumption between gas heated and electrically heated homes (delivery date: June 2009).
- Market Segmentation Analysis – the determination of customer groupings (segments) within Terasen's residential customer base, based on a pairings of socio-demographic characteristics, behaviours, and attitudes (delivery date: June 2009).

2 BACKGROUND & METHODOLOGY

2.1 Sample Design

The sample frame for the 2008 REUS included Rate 1 residential Terasen Gas customers from each of the following five regions:

- Lower Mainland (LM)
- Interior (INT)
- Vancouver Island / Sunshine Coast (TGVI)
- Whistler (TGW)
- Fort Nelson (FN)

These customers were further stratified by the following three building types:

- Single Family Detached (SFD) – all individually metered single family detached dwellings, including mobile homes.

- Vertical Sub Division (VSD) – an individually metered suite within a multi-storey building with a common Service Header connecting banks of meters, typically located on each floor.

- Other Multi-Family Dwelling (MFD) – an individually metered unit within a multi-unit residential dwelling, with up to four meters (each serving a unit) on one “service”. Typically includes duplexes, row houses, and townhouses.

Stratification by building type met the objectives of the conditional demand analysis, and Terasen’s desire to understand the end use characteristics for these building types.

Exhibit 2.1 summarizes the number of customers by region and building type.

Exhibit 2.1: Sample Frame – 2008 Residential End Use Survey

Region / Business Unit	SFD	VSD	MFD	Total
Lower Mainland (LM)	466,000	2,700	41,000	509,700
Interior (Inland and Columbia) (INT)	211,000	600	8,000	219,600
Vancouver Island / Sunshine Coast (TGVI)	76,000	50	4,000	80,050
Whistler (TGW)	1,300	0	700	2,000
Fort Nelson (FN)	1,800	0	40	1,840
Total (TG)	756,100	3,350	53,740	813,190

A disproportionate sampling plan was used with an initial target 2,715 completed surveys. The sampling plan was designed to satisfy the following criteria:

- statistical representativeness of the results by region and building type;
- minimum sample sizes for conditional demand analysis (CDA); and
- availability of two years of billing data for each customer account for use in the CDA.[1]

[1] The requirement for two years of uninterrupted billing history is acknowledged to introduce some bias into the sample, as it excludes all homes newer than two years, and all customers who have moved premises in the past two years. This bias was considered a necessary compromise to complete a conditional demand analysis.

The maximum number of completions expected for VSDs and MFDs for some regions was constrained by small or zero population counts. For VSDs, this was the case for TGVI, W, and FN. For MFDs, this affected the FN only. The initial survey targets are summarized in Exhibit 2.2.

Exhibit 2.2: Stratified Sample Plan – 2008 REUS Targets

Region	SFD	VSD	MFD	Total
LM	400	200	200	800
INT	400	150	200	750
TGVI	400	5	200	600
TGW	200	0	154	359
FN	200	0	6	206
TG Total	**1600**	**355**	**760**	**2715**

2.2 Questionnaire Design

To ensure the results from the 2008 REUS survey and accompanying analyses could be compared with the results from the 2002 and 1993 REUS studies, attention was devoted, where possible and where reasonable, to ensuring compatibility with previous survey sampling and questionnaire designs. Experience with the performance of questions from past surveys, plus new and expanded objectives for the 2008 survey, led to the reworking of some questions, and the inclusion of new questions or entire sections. Sections or questions that were no longer of interest to Terasen Gas were deleted.

The following are a list of additions, expansions/modifications, and deletions from the 2002 REUS questionnaire:

Additions:

- apartments and condominiums - location of the unit within the building structure (e.g., end / corner unit, top floor unit)
- ceiling heights
- text box descriptions to help respondent differentiate between domestic hot water tanks and boilers
- identification of most used secondary heating method in additional to all secondary heating methods
- type(s) of water heaters (storage tank versus instantaneous hot water heater, etc.)
- length of showers (total minutes per typical weekday)
- pilot light usage for gas fireplaces
- incidence and use of programmable thermostats
- questions regarding ventilation systems used to bring in fresh air
- presence of Energy Star® qualified appliances
- number of months pools and hot tubs are heated
- new section on household energy use behaviours

Expansions / modifications of existing questions / topics:

- expansion of utilities included in rent or monthly maintenance fees
- expanded detail on basement design and heating
- expanded detail on energy efficient windows, including the incidence of argon gas fills, and whether they are Energy Star® qualified
- expansion of outside door categories to include glass doors
- expanded furnace type descriptions to help the respondent identify the efficiency level of their furnace

- expansion of fireplace section to include stand alone heating stoves
- new fireplace and heating stove descriptions, including text box descriptions
- expansion of hot water heating section to include solar pre-warming
- distinction between bottled gas and piped gas barbeques and patio / outdoor heaters
- expand section on appliance penetration and saturation
- identification of pools and hot tubs shared with other residences (e.g., condominiums, townhouse complexes)
- expansion of renovation (undertaken and planned) questions to include new fireplace and heating stove definitions
- rework of section querying interest in potential new products and services

Deletions / Removals:

- interest in various tariff options
- sources of information on products and services
- communications with Terasen Gas

All changes to the 2008 survey were approved by Terasen Gas prior to fielding the survey questionnaire.

2.2.1 Final Questionnaire Design

The 2008 REUS questionnaire approved by Terasen consists of 11 sections, including:

- Dwelling characteristics
- Space heating
- Fireplaces and heating stoves
- Domestic water heating
- Appliances
- Swimming pools and hot tubs
- Energy use and renovations
- Managing household energy use (behaviours)
- Products and services
- Attitudes towards energy use
- Demographics

The final version of the questionnaire is included in Appendix A.

2.3 Survey Implementation

The Vancouver office of NRG Research was responsible for implementing the survey, data cleaning, tabulating the results, and managing the incentive.

A total of 11,260 questionnaires were mailed out in the second week of November 2008. Reminder cards were mailed five days later. Respondents had the choice of completing and returning a paper copy of the survey or completing the survey online. A total of 2,221 useable surveys were received, with 38% being completed online. The overall response rate was 20%. Exhibit 2.3 summarizes the response by region and building type.

Regional response rates were highest for TGVI customers (27%) and lowest for TGW customers (13%). A lower response rate was expected for TGW customers because of the high proportion of absentee ownership.

Exhibit 2.3: Survey Response Summary

Region	Response				Response Rate (Response / Mail Out)			
	SFD	VSD	MFD	TG Total	SFD	VSD	MFD	TG Total
LM	293	114	170	577	16%	13%	19%	16%
INT	435	123	173	731	27%	21%	22%	24%
TGVI	370	6	190	566	27%	32%	27%	27%
TGW [1]	133	--	76	209	14%	--	12%	13%
FN [1]	137	--	1	138	15%	--	5%	15%
TG Total	**1368**	**243**	**610**	**2221**	**20%**	**16%**	**20%**	**20%**

[1] No vertical subdivisions present

Exhibit 2.4 summarizes the survey response by response channel. TGW and FN residents were most likely to submit an online response (52% and 44% respectively).[2]

Exhibit 2.4: Survey Response Summary – Online Versus Mail (%)

Response channel	LM	INT	TGVI	TGW	FN	2008 TG
Online	37.9	35.2	35.0	52.2	44.2	37.7
Mail	63.1	64.8	65.0	47.8	55.8	62.3
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

2.4 Weighting of Results

Weights were used to restore the relative proportions of each region and building type combination to that of the survey population. The weights were calculated using equation (1):

$$W^{r,b} = (P^{r,b}/P^{TG}) \,/\, (S^{r,b}/S^{TG}) \qquad (1)$$

W = weight
P = population
S = survey
r = region
b = building type
TG = total of all Terasen Gas regions and building types

Exhibit 2.5 presents the weights calculated using this formula and used in the 2008 REUS analyses:

Exhibit 2.5: REUS 2008 Weights

Region	SFD	VSD	MFD	Total
LM	4.32906	0.06468	0.65872	2.40848
INT	1.32479	0.01347	0.12633	0.82162
TGVI	0.56101	0.02221	0.05751	0.38628
TGW	0.02672		0.02513	0.02614
FN	0.03583		0.11105	0.03637
All Region Average	1.50845	0.03781	0.24063	1.00000

[2] The final number of usable surveys excludes duplicate surveys from a small number (30) of customers who responded using both methods. The two responses for each customer were reviewed for consistency and completeness. In the end, the online versions were used in the analyses because they were generally more complete (i.e., had fewer questions with non-responses).

2.5 Accuracy of Survey Estimates

The margin of error (accuracy level) for questions varies by region, building type, and the degree of consensus. Exhibit 2.6 summarizes the accuracy levels at the 95% confidence level for a typical range of “yes-no” type questions for each of the five Terasen regions, TG, and TGI. At the Terasen Gas (TG) level, a typical question with a “50-50” response (e.g., 50% answering yes, 50% answering no) will have an accuracy of plus or minus 3.2%, 19 times out of 20.[3] The margin of error decreases as the consensus of the estimate increases. Thus, a yes-no type question with 90% answering yes will have an accuracy of plus or minus 1.9%, 19 times out of 20.

Exhibit 2.6: Accuracy Levels for Proportional Responses by Region (%)
Percent Plus or Minus at the 95% Confidence Level

Proportional Response \ Accuracy	LM +/-	INT +/-	TGVI +/-	TGW +/-	FN +/-	TG +/-	TGI +/-
50%	4.1	3.6	4.1	6.8	8.3	3.2	3.5
40% or 60%	4.0	3.6	4.0	6.6	8.2	3.2	3.4
30% or 70%	3.7	3.3	3.8	6.2	7.6	3.0	3.2
20% or 80%	3.3	2.9	3.3	5.4	6.7	2.6	2.8
10% or 90%	2.4	2.2	2.5	4.1	5.0	1.9	2.1
Number of respondents (unweighted)	577	731	566	209	138	2221	1446

Exhibit 2.7 provides the information on margin of error for the three building types.

Exhibit 2.7: Estimated Accuracy Levels for Proportional Responses – Building Type
95% Confidence Level

Proportional Response \ Accuracy	SFD +/-	VSD +/-	MFD +/-	TG +/-
50%	2.6	6.3	4.0	3.2
40% or 60%	2.6	6.2	3.9	3.2
30% or 70%	2.4	5.8	3.6	3.0
20% or 80%	2.1	5.0	3.2	2.6
10% or 90%	1.6	3.8	2.4	1.9
Number of respondents (unweighted)	1368	243	610	2221

[3] Consistent with the disproportionate sampling method used in this study, the formula used to calculate the margin of error for the overall Terasen Gas sample at the 95% confidence level is defined as:

$$= 1.96 * SQRT\left(\sum_i \left(W^2_i \left((1-f_i) \times (s^2_i/(n_i-1))\right)\right)\right) \quad \text{for } i = 1 \text{ to } g$$

where:

SQRT = square root
W = stratum population divided by the total population
f = stratum sample divided by stratum population
s = variance in the stratum
n = stratum sample size
i = sample stratum
g = total number of sample strata (15)

Finally, the margin of error for TGI estimates, for each of the survey years, is presented in Exhibit 2.8.

Exhibit 2.8: Estimated Accuracy Levels for Proportional Responses – TGI
95% Confidence Level

Proportional Response \ Accuracy	TGI 2008 +/-	TGI 2002 +/-	TGI 1993 +/-
50%	3.2	2.4	1.4
40% or 60%	3.2	2.4	1.4
30% or 70%	3.0	2.2	1.3
20% or 80%	2.6	2.0	1.1
10% or 90%	1.9	1.5	0.8
Number of respondents (unweighted)	2221	1610	4814

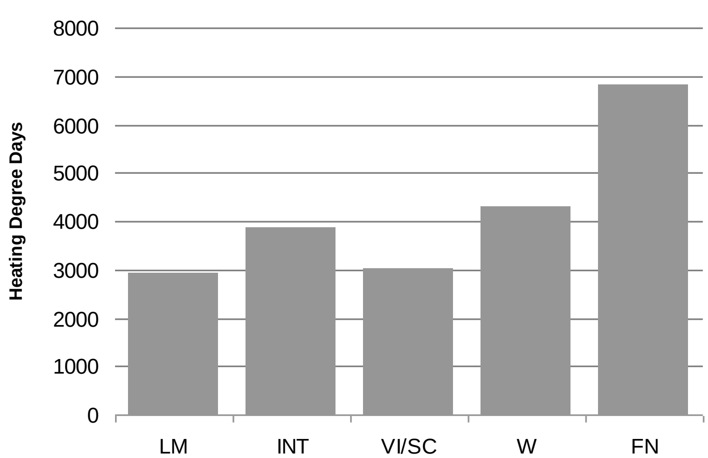
2.6 Definitions & Explanatory Notes

The following definitions and notes are included to aid in the interpretation of survey results, and the general readability of the report.

Heating Degree Day (HDD) - Defined as the difference between a reference value of 18°C and the average outside temperature for that day. The frequency and amount by which the outside temperature falls below 18 degrees Celsius provides a good indication of the amount of heating required to maintain a comfortable indoor temperature. The relative need for space heating is directly proportional to the severity of the winter, which is indicated by the number of HDDs.

Regional Differences in Heating Degree Days - Figure 2.1 shows that relative severity of winter in Terasen's five regions, as indicated by 30 year HDD averages, can vary significantly. LM and TGVI regions have the warmest winters (each with approximately 3,000 HDDs), while winters in the INT and TW regions are colder (approximately 3,800 and 4,300 HDDs). The northerly FN region is the coldest, recording more than 6,800 HDDs in a typical year.

Figure 2.1: Typical Annual Heating Degree Days by Region



Source: Environment Canada, 1971-2000 Climate Normals

Regional differences in average winter temperatures can be an important factor influencing regional differences in such things as housing construction trends, and the stock and operation of space heating equipment.

Conditional Demand Analysis (CDA) – a statistical method for proportioning total household natural gas consumption into the respective individual gas end uses (e.g., space heating, domestic hot water, cooking, etc.) using data on the penetration and saturation of end uses matched with billing consumption data. As an indirect approach to the estimation of end use consumption, diversity in the penetration, saturation, and usage of the end uses within the sample population is required for the model to estimate (isolate) the consumption of the end use from the other gas-using end uses in the home.

Unit Energy Consumption (UEC) – the annual energy consumed by a piped gas or propane end use in a given year. UECs are estimated by conditional demand analysis. The size of an end use's UEC estimate is affected by its purpose (e.g., cooking, space heating, etc.), its efficiency, and how it is used (behaviours). UECs for some end uses, particularly space and water heating, are weather dependent.

Penetration – Defined as the number of households with a particular appliance or end use divided by the total number of households with or without the appliance or end use. Penetration is used to understand the proportion of Terasen's residential customer base with the appliance or end use in question. Penetration does not concern itself with how many of the appliances or end uses an individual household has, only the presence of at least one. Commensurately, the upper limit on any penetration estimate is 100%.

Saturation – Defined as the number of appliances or end uses divided by the total number of households with and without the appliance or end use. Saturation provides an estimate of the average number of specific appliances or end uses per typical Terasen residential customer. Saturation estimates are influenced by two factors: (i) the number of appliances or end uses present in user households, and (ii) the penetration of the appliance or feature in the general population. For example, the saturation of low flow shower heads is a function of how many households use them and the number installed in each of these homes. Since homes may have more than one appliance or end use, there is no upper limit on saturation estimates.

1993 TGI – Various tables will show comparisons with data from the 1993 residential end use survey. TGI estimates for 1993 include the Lower Mainland, Interior and Columbia, and Fort Nelson regions. All comparisons to the 1993 dataset use data sourced from the 2003 REUS report (Habart 2003).

2002 TGI - represents data from Terasen's 2002 residential end use survey, representing Lower Mainland, Interior and Columbia, and Fort Nelson regions. Comparisons to 2002 REUS results use data that was published in the 2003 report (Habart 2003), supplemented or substituted where necessary with data from cross tables.

2008 TGI - represents data from Terasen's 2008 residential end use survey, representing Lower Mainland, Interior, Columbia, and Fort Nelson regions.

2008 TG - data from Terasen's 2008 residential end use survey including customers from all five regions, including Lower Mainland, Vancouver Island / Sunshine Coast, Interior and Columbia, Whistler, and Fort Nelson regions.

Gas – Geographic coverage for the 2008 REUS survey included regions currently serviced by piped propane (Whistler, Revelstoke). Unless otherwise stated, all references to "piped gas" in the report refer to either piped gas or piped propane.

Unweighted Base – All tables present the unweighted base for which the statistics were calculated. These numbers reflect the actual number of valid survey response responses received, corresponding to each column or row, depending upon the layout of the table. Calculations by region, or by building type are based on weighted data to ensure proportionate representation from Terasen regions and the three primary building types. The size of the unweighted base is useful for help guide comparisons with other data and understanding the relative accuracy of the estimate. Unless indicated otherwise, unweighted bases indicated in this report exclude non-responses or missing values (see definition of non-response, below). As the proportion of non-response may vary slightly from question to question, the unweighted base may change somewhat from question to question depending upon the degree of non-response.

Don't Know (DK) responses – Some questions on the 2002 and 2008 residential end use surveys include a "don't know" (DK) response category. The relative proportion of respondents who answered DK provides useful information, and often is related to the complexity of question's subject. In some cases, it is legitimate to recalculate the proportions of the other categories without the DK responses. Effectively, this recalculation proportions the DK responses to the remaining categories in the same proportions as those who provided a valid, non-DK response (i.e., assumes the distribution of the DK responses is proportional to those who provided a response). Re-proportioning DK responses is not valid in cases where this "proportionate distribution" assumption does not apply. For example, uncertainty regarding furnace efficiency level may be proportionately higher for households with mid- or standard efficiency furnaces than for those with high efficiency furnaces. In a case such as this, a DK response should be treated as a legitimate response and included in the base for calculating the relative proportions of the other response categories.

Non-Response (NR) – Sometimes categorized as missing values, they refer to cases where a respondent did not answer a question, leaving the response categories for the question blank. This action may be as intended by the survey designer (i.e., the respondent is following instructions to skip the question). These are different than in cases where the respondent simply chose not to answer a question for whatever reason. In these latter cases, non-responses are treated differently from don't know (DK) responses as they neither imply uncertainty or certainty of a response. Indeed, they provide no information from which to extrapolate a response. All calculations in this report, unless stated or indicated otherwise, exclude missing values. This is done to avoid distorting the proportions assigned to the response categories based on those who answered the question. The majority of questions on the 2008 REUS include a small (typically less than 5%) non-response.

Of note, the 2002 REUS report grouped non-responses and don't know responses together. In cases where the 2002 survey questionnaire did not provide a separate DK response category (e.g., check box), it was assumed that all responses in the DK/NR were missing values. The proportions for these questions were recalculated to exclude these missing values, placing them on a comparable basis to the 2008 results. In situations were a DK response category was provided, the DK/NR estimate from the 2002 REUS was left unchanged and reported as is.

Significant Digit Conventions – Except otherwise indicated, all data presented and discussed in the text of this report are rounded to the nearest significant digit to aid readability. To facilitate subsequent analyses and calculations by the Terasen, data presented in exhibits are expressed to one decimal place. This also allows the exhibits to accommodate the occasional small response proportion (i.e., proportion less than 1%).

Figures – Refers to a graphic illustration or other form of visual interpretation of data. Figures are used in situations where they useful for illustrating trends, relationships, or simply facilitating comparison.

Exhibits – Refers to data presented in tabular format.

Footnotes – With the exception of footnotes in exhibits, footnotes referenced in the text of the report are found at the bottom of the page.

Additional Notes to Tables

n/a Not Applicable – Indicates when data is unavailable for comparison.

-- No responses were received for the particular category or cell

0.0* Value less than 0.1

3 TRENDS

This section presents and discusses key socio-demographic, equipment efficiency, and new construction trends influencing the consumption of natural gas among Terasen's residential gas customers. This section serves two primary purposes. One is to provide the context for understanding and interpreting the findings from the 2008 REUS survey, particularly in comparison with the 2002 and 1993 REUS surveys. The other purpose is to understand how these trends and developments may influence residential gas consumption over the short- and medium-term.

3.1 Natural Gas Use Rates

Natural gas consumption on a per-household (per-account) basis, normalized for year-to-year variations in temperature, has declined in the Terasen Gas operating area, on net, since 2002. The trend to declining use rates has also been experienced in other jurisdictions in North America.

Exhibit 3.1 summarizes weather normalized annual use rates for Terasen's residential gas customers for 1999 to 2008. The data show that all regions, except TGW, experienced declines in their use rates over the analysis period. Of note, use rates in the LM and TGVI regions declined by 16% and 15% respectively since 2002. However, INT region use rates have declined by 27% since 1999, significantly more than the 18% decline in the LM region use rate. The TGW region stands out as the only region which has experienced an increase in their use rate since 2002 (+6%). Overall, TG use rates in 2008 are 16% below 2002 levels, and 21% below 1999 levels.

Exhibit 3.1: Weather Normalized Use Rates – 1999-2008

Year	LM	INT	TGVI	TGW	FN	TG
1999	121.9	104.5	71.9	94.8	161.4	114.1
2000	116.9	99.5	68.4	91.8	158.0	109.2
2001	105.2	88.1	66.2	87.9	167.3	98.4
2002	118.4	89.5	66.6	89.4	156.5	107.1
2003	111.5	89.2	61.8	90.6	162.3	102.3
2004	108.3	86.1	59.0	85.7	166.4	99.1
2005	103.6	82.4	58.7	93.4	153.7	95.0
2006	103.2	82.0	60.2	85.6	141.5	94.7
2007	102.6	80.8	57.0	95.7	141.9	93.8
2008	99.5	76.5	56.1	95.2	139.6	90.5
Change 1999-2008	**-18.4%**	**-26.8%**	**-22.0%**	**0.4%**	**-13.5%**	**-20.7%**
Change 2002-2008	**-15.9%**	**-14.5%**	**-15.8%**	**6.4%**	**-10.8%**	**-15.5%**

3.2 Factors Influencing Use Rates

Several factors influence use rates. Changes in behaviours and the penetration, saturation, and efficiency of the stock of energy-using equipment influence gas consumption over time. Some changes are short-term and transient, such as behavioural responses to a short-lived increase in the price of natural gas. Others occur over a much longer time frame and are more sustained, such as long-run trends in new housing construction (type, size, etc.) and legislated improvements in the efficiency of gas furnaces and hot water-using appliances.

Determining the relative influence of the factors underpinning the short- and long-run decline in natural gas use rates, is difficult and complex. The purpose of this section is not to quantify interactions or causal factors, but, rather to present an overview of the key trends and developments influencing gas use rates among Terasen's residential customer base. Specifically, the following factors are addressed in this section:

- the changing socio-demographic characteristics of Terasen's residential customer base;
- changes to the efficiency of furnaces and appliance stocks;
- changes in the composition of new housing stock, including changes in building codes affecting energy consumption; and
- short-term and long-term responses to changes in price (elasticities).

3.3 Socio-Demographic Characteristics

Two socioeconomic trends are noteworthy in their influence on natural gas consumption trends: the aging of the population, and the declining number of people per-household.

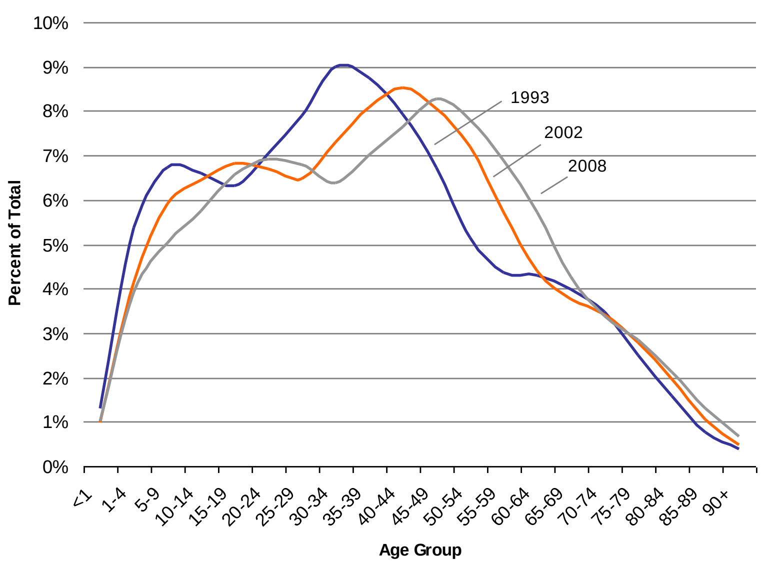
3.3.1 Aging Population

Terasen's residential customer base is aging. This has implications for average household gas consumption, as older individuals differ from their younger counterparts in their demand for natural gas space and hot water heating.

Data on household energy use and equipment collected by the US Energy Information Administration (EIA) in 2005 found that natural gas usage for space heating was 13% higher in homes with seniors compared to those without. Conversely, gas consumption for water heating was 13% lower in homes with seniors than those without. The presence of children between 5 and 16 years of age increased gas consumption for space heating and water heating by 5% and 39% respectively.[4]

The aging of the Terasen population base since 1993 is shown in Figure 3.1 in the form of shifting age profiles. Of note, individuals between the ages of 25 and 44, the age segment most highly associated with household formation, has decreased from 34% in 1993 to 28% in 2008, while the proportion of the population aged 45 to 64 increased from 21% to 29%. Fifteen percent (15%) of individuals are now aged 65 years and older, up slightly from 13% in 1993.

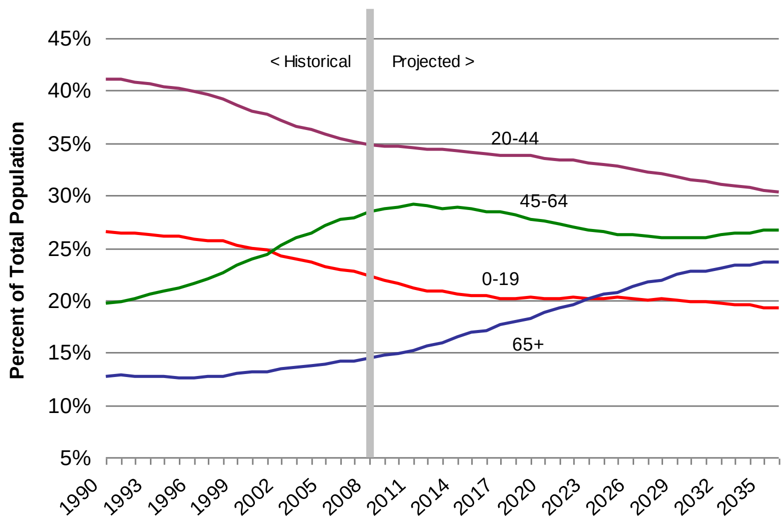
Figure 3.1: British Columbia Age Profiles – 1993, 2002, 2008



[4] Source: Energy Information Administration, *2005 Residential Energy Consumption Survey*, U.S. Department of Energy.

The aging of the population is forecast to continue over the long-term. Figure 3.2 shows that the cohort comprised of children and young adults as a share of the total population has been in decline since 1990 and is expected to continue declining during the next quarter-century. Commensurately, the relative share of the population made up of seniors (those aged 65 years or older) is expected to increase to well over 20% over the long-term.

Figure 3.2: Population Share (%) by Age Group – British Columbia



Data source: BC Stats

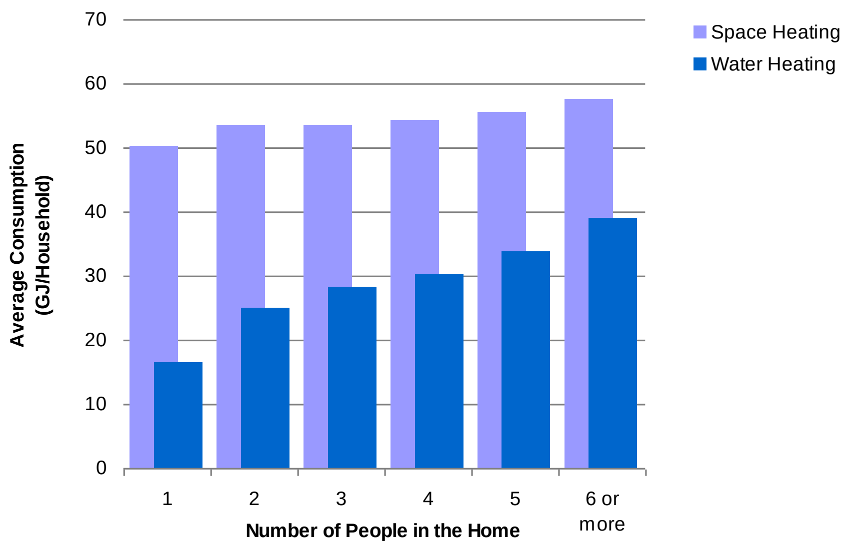
3.3.2 Declining Household Size

The aging of the population is being accompanied by a slow but consistent decline in household size, as measured by the average number of people in the home. This decline stems, in part, from the long-run trend towards having fewer children, but also from the increased presence of older households where the children have left the home. The declining number of people in the home has implications for space and water heating demand.

Figure 3.3 summarizes the results from the 2005 EIA study which found that natural gas consumption for space and water heating decreased as the number of people in the home decreased.[5]

[5] Comparable data for Canada is expected upon release of the Statistics Canada's 2008 *Survey of Household Energy Use*. These data were not available at the time of this report's preparation.

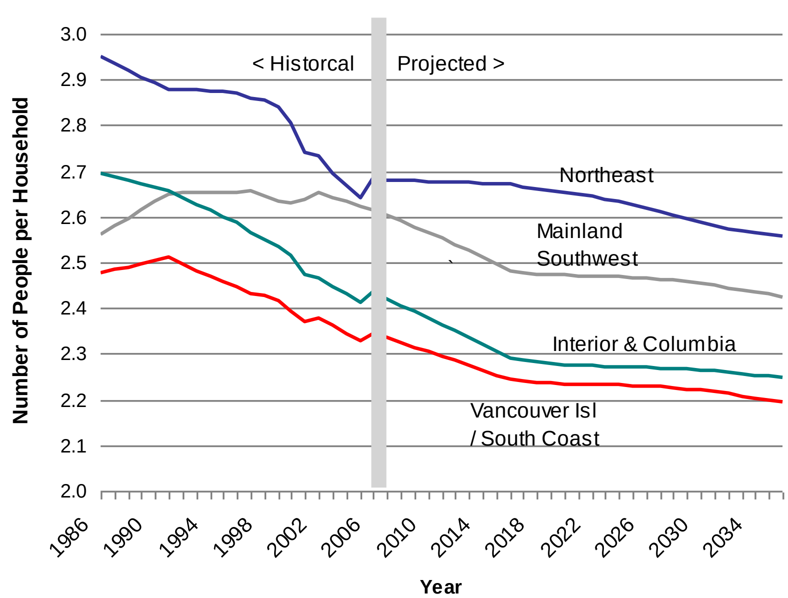
Figure 3.3: Gas Consumption by Number of People in the Home



A one person household was estimated to consume 6% less natural gas for space heating compared to a two person household. The relationship between space heating and household size is not strictly linear. Indeed, the amount of energy to keep a two person household warm did not vary much between a two person household and a four person household. Natural gas use for water heating shows a much stronger relationship between household size and consumption, rising from 16 GJ for a one person household to 39 GJ for households with six or more people.

Figure 3.4 illustrates the long-run declining trend for average number of people per-household for the Statistics Canada Census regions that correspond most directly with Terasen Gas's customer regions (Mainland / Southwest includes Whistler).

Figure 3.4: Average Number of People per Household – History and Projection

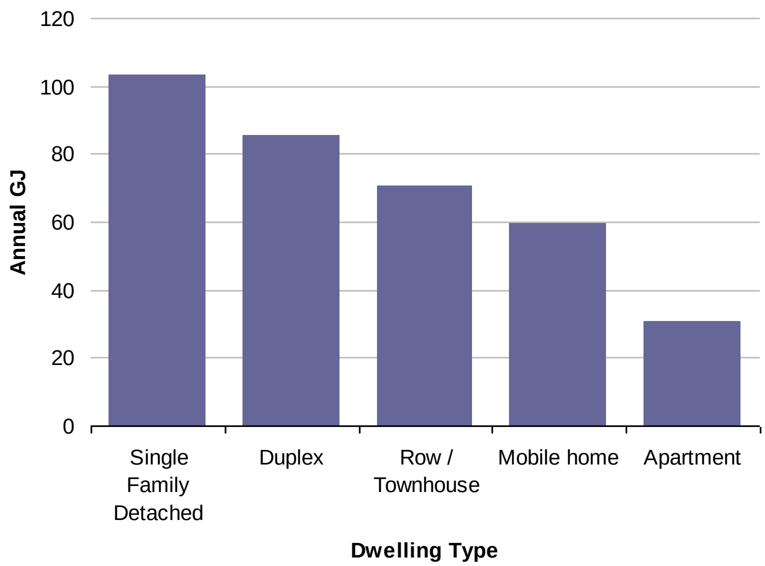


All regions experienced declines, although the sharpest declines have been experienced outside the Mainland-Southwest region.

3.3.3 Building Construction Trends

Gas consumption varies by the type of residential dwelling. Trends in new housing construction, including the relative proportion of single family detached, semi-detached, apartments, mobile homes, and other dwelling types have an impact on overall energy consumption. Figure 3.5 illustrates differences in average annual gas consumption for the five main dwelling types of households that responded to the 2008 REUS survey. The data show that, relative to single family detached dwellings, duplexes use 17% less gas, row / townhouses use 32% less, apartments use 70% less, and mobile homes consume 42% less gas. Several dwelling-specific factors explain this relationship, including floor space, number of people in the home, the presence or lack of common walls (e.g., duplexes, townhouses, etc), and the mix of gas appliances and end uses.

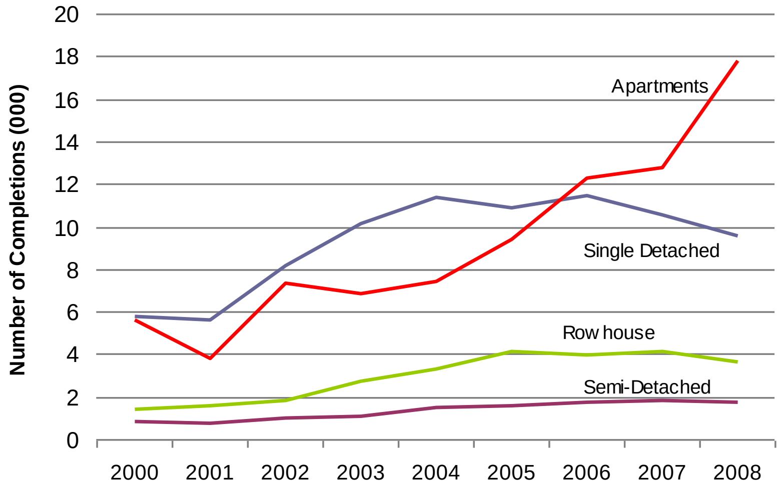
Figure 3.5: Average Annual Consumption (GJ) by Dwelling Type - TG



New housing trends influence longer run trends in natural gas use. Of note, housing construction in British Columbia is shifting towards multifamily dwellings such as apartments, row houses, and semi-detached dwellings (Figure 3.6).

Of note, the number of apartments constructed in urban areas of British Columbia has gone from approximately 5,600 units in the year 2000 to 17,800 units in 2008. In comparison, approximately 9,500 single family detached dwellings were completed in 2008. Since newly built dwellings represent only a 1% to 2% increase in the total stock of housing in British Columbia in a given year, new construction trends influence the relative composition of the stock of housing relatively slowly over the long-run.

Figure 3.6: Housing Completions – Urban BC



Data source: CMHC

3.3.4 Construction Codes and Standards

Residential building codes and standards have generally expanded their scope over time from an initial focus on health and safety, to the inclusion of specific provisions for energy and water efficiency.

Energy Efficiency Trends & Regulations – Single Family Dwellings

Recent changes to the British Columbia Building Code and the British Columbia Energy Efficiency Act will impact new construction of small buildings and residential detachments (up to 600 square meters or 6,500 square feet). The British Columbia Building Code defines minimum building practices in all areas of British Columbia except Vancouver.

Changes to the building code took effect as of September 5, 2008. It requires new construction to meet an EnerGuide 77 rating.[6] Prior to this, new homes were typically achieving EnerGuide ratings of 71 to 72. Changes to the building code pertain to insulation levels in walls, with the new code requiring framed walls to have RSI 3.5 (R20) for non-electrically heated homes in areas with less than 3,500 heating degree days. Previously, the code permitted walls to be insulated to RSI 2.4 (R14) in these areas. Planning is underway to further increase the requirements for homes to meet an EnerGuide rating of 80, beginning in 2010.

The City of Vancouver has its own Charter and has not adopted the BC Building Code. Instead, new construction within city boundaries is regulated by the Vancouver Building Bylaw. Requirements in the City of Vancouver are more stringent than the provincial building code. New homes are required to achieve an EnerGuide 80 rating.

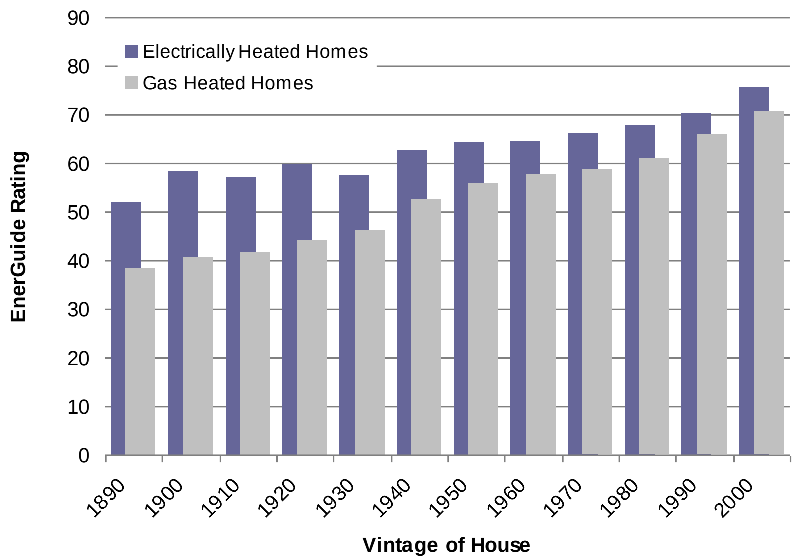
In addition to the increased overall performance of buildings due to changes in the building code, the BC Energy Efficiency Act was amended in June 7, 2008 to require:

[6] The EnerGuide rating is a general indicator of a home's energy efficiency. A professional EnerGuide energy advisor calculates the rating based on information on the home's energy systems, construction materials and assembly, and the results of a blower door test with modeling software developed by Natural Resources Canada. The rating ranges from 0 to 100, with a rating of 100 equivalent to a net-zero energy home. Source: Natural Resources Canada (oee.nrcan.gc.ca)

- Condensing furnaces (i.e., AFUE of 90% or higher) in new construction (previous requirements were for mid-efficiency furnaces (AFUE 78%)
- Energy Star® rated windows with a minimum performance of U=2.0.[7]

Changes to the building code and their impact on the energy performance of homes in British Columbia are illustrated by comparing the average EnerGuide rating assigned to homes according to their year of construction (Figure 3.7). The data show a general improvement over time in the energy performance of homes in British Columbia. The data are based on approximately 20,000 EnerGuide for Houses audits. An EnerGuide rating of 0 represents a home with major air leakage, no insulation, and extremely high energy consumption. A rating of 100 represents a home that is airtight, well insulated, sufficiently ventilated and requires no purchased energy. Presently, a rating of 80 or more for a new home is considered an excellent rating.

Figure 3.7: EnerGuide Rating for Homes in British Columbia



3.3.5 Offsetting Factors

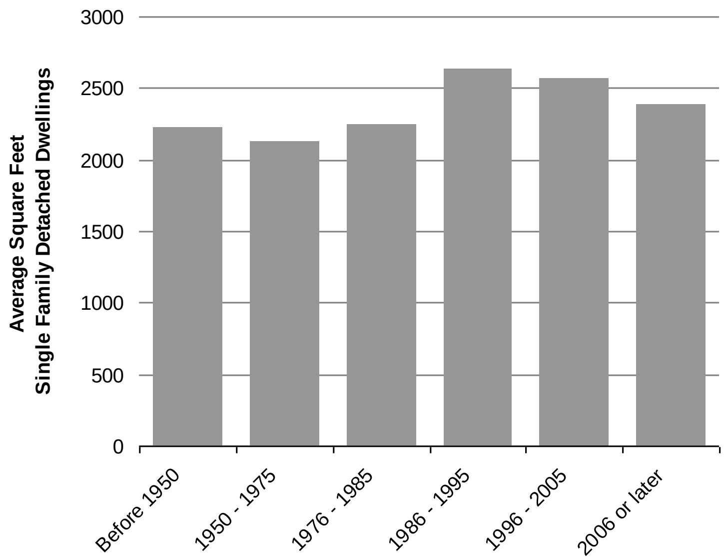
While these results demonstrate that new homes use less energy, the reduction in energy consumption has been offset somewhat by other factors, including:

- trend toward increased home size (square footage) in new homes;
- trend towards increased glazing areas of new homes; and
- trend toward increased interior volume of new homes due to the increase in average ceiling height.

The trend towards increasing home size, as measured by the amount of floor space including basements, is evident among respondents to the 2008 REUS. Generally speaking, single family detached houses constructed after 1985 are larger, on average, than those constructed earlier (Figure 3.8). The trend towards larger floor plans, everything else held constant, means an increased space heating load. The slight decline in average floor space for single family detached homes built after the 1996-2005 period is not statistically significant due to the small sample homes built since 2005 included in the 2008 REUS.

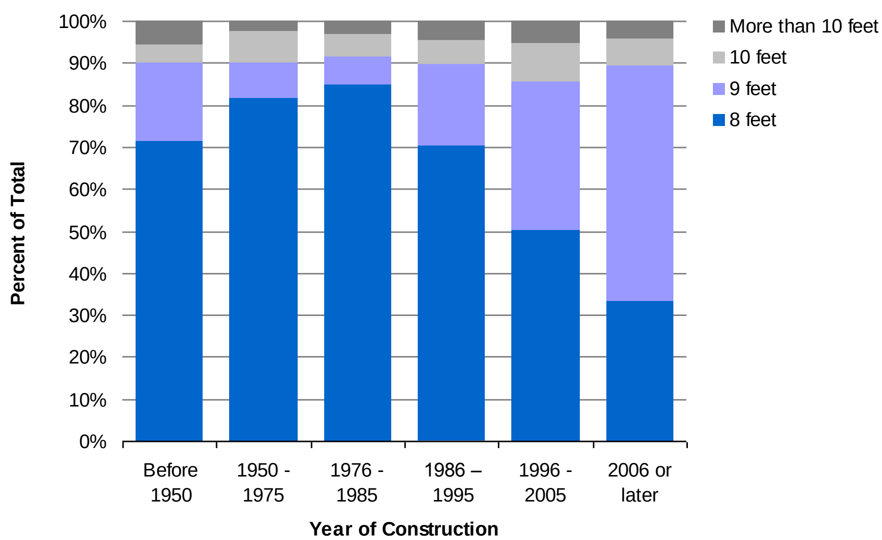
[7] As of January 1, 2009, the maximum U-value for fenestration products, excluding skylights, solid wood framed windows, and sliding glass doors decreased to 2.0 W/(m2 x K) and 3.1 W/(m2 x K) for skylights. As of January 1, 2011, all fenestration products, except skylights, will be required to meet a maximum U-value of 2.0 W/(m2 x K).

Figure 3.8: Average Floor Space of SFDs by Year of Construction



Accompanying the trend toward increased home floor plans, there is an increased likelihood of nine and ten foot ceilings among the homes of REUS 2008 respondents living in homes constructed since 1985 (Figure 3.9). The increase in the interior volume of homes (floor space times ceiling height) increases the size of the space heating system needed to service the home.

Figure 3.9: Ceiling Height Trends



Further research is needed to quantify the extent and importance of these drivers in offsetting the trend towards improved energy efficiency of residential dwellings.

3.3.6 Energy Efficiency Trends & Regulations – Apartment Buildings

Apartment buildings larger than 600 square meters (~6,500 square feet) and less than 4 stories in height are generally regulated under Part Two of the building code. As of September 5, 2008, new commercial buildings are required to meet ASHRAE 90.1-2004.[8] Historically there have been no requirements for energy efficiency of large buildings.

ASHRAE addresses:

- thermal envelope
- heating ventilation and air conditioning
- domestic hot water
- electrical systems
- lighting systems

It is expected that compliance with the requirements of this code will reduce energy use in new buildings by 15% below unregulated buildings.

Other Initiatives and Developments

New Construction

British Columbia is second only to Ontario in the number of residential projects, including apartment buildings, registered to meet the LEED (Leadership in Energy and Environmental Design) standard for green buildings. The LEED standard encourages designs that exceed code minimums in a range of performance categories, including energy use.[9] LEED is structured to require minimum performance in accordance with ASHRAE 90.1. Points are awarded for performance that reduces energy use below the prerequisite.

The ecoENERGY program supports energy efficient new homes. Natural Resources Canada runs the program with local delivery agents.

The Built Green™ program was offered by the Canadian Home Builders and operated in the province between 2005 to 2008. Beginning in March 2009, the Canada Green Building Council will start to provide LEED for Homes to encourage more sustainable and energy efficient residential construction.

The Power Smart New Home Program run by BC Hydro offers financial incentives, promotional opportunities, and Power Smart branding to builders who are constructing single family homes, townhouses, and multifamily residential dwellings to the EnerGuide for New Houses standard.

Existing Homes

The Livesmart program is a joint initiative between the British Columbia and federal governments to provide information and incentives to consumers to reduce energy use and greenhouse gas emissions. The program provides a range of incentives to support energy efficient home retrofits, including home energy audits, and financial rebates on a range of energy-using appliances and equipment such as insulation, draft sealing, furnace upgrades and window replacements.

[8] This is a standard developed by the American Society of Heating Refrigeration and Air Conditioning Engineers (ASHRAE), and has been adopted by over 30 states in the USA.

[9] LEED green building rating system is a rating tool and assessment methodology developed by the US Green Building Council, and delivered in Canada by the Canada Green Building Council (CaGBC). Source: www.cagbc.org/leed/

Existing Apartment Buildings

Energy use in existing apartment buildings remains an area of uncertainty. Work to improve the understanding of the interaction between electric suite heat and gas-fired corridor make-up air units is ongoing.

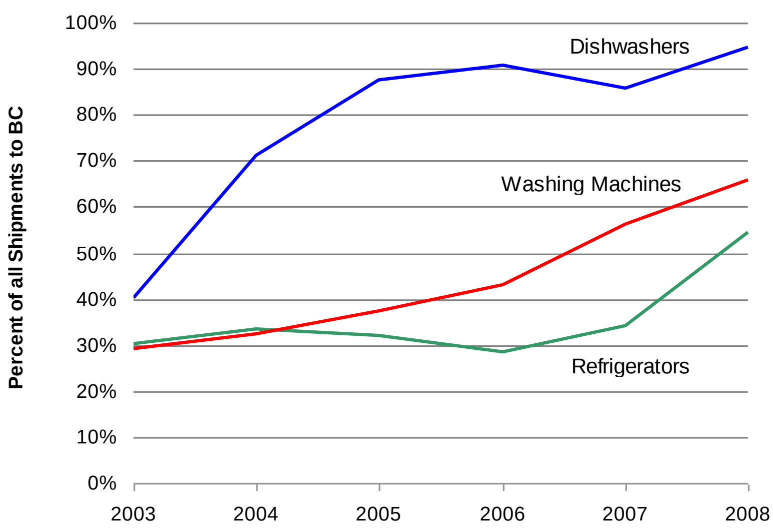
Work to develop a labelling tool is ongoing, and the Province of BC, Natural Resources Canada, the Canada Green Building Council and the City of Vancouver are all developing a building labelling tool that may be used to assess energy performance in existing apartments.

3.3.7 Appliance Efficiency Standards

The influence of socio-demographic and dwelling construction trends on residential energy use have been accompanied by improvements in the energy efficiency of major home appliances that either use natural gas directly (e.g., gas furnaces) or indirectly through the demand for hot water heating (e.g., horizontal axis clothes washing machines).

There is no single measure that adequately summarizes the efficiency trends in new appliances, or the general improvement in efficiency of the stock of appliances. Changes in the energy efficiency mix of dishwashers, washing machines, and refrigerators sold in British Columbia can be illustrated using shipments data on Energy Star® qualified models provided by the Canadian Appliance Manufacturers Association (Figure 3.10). The data show that the proportion of dishwashers shipped to BC that are Energy Star qualified has risen from 40% in 2002 to over 90% in 2008. Energy Star qualified washing machines and dishwashers have also increased their market share over the last six years. These data understate the extent of the improvement in energy efficiency of these appliances, as the minimum standards for Energy Star qualifications, for some appliances, have been revised upward over time.

Figure 3.10: Energy Star® Share of Appliance Shipments to British Columbia – 2003-08



Data source: CAMA

Exhibit 3.2 summarizes past and proposed changes in the energy efficiency standards and regulations for:

- gas furnaces

- gas boilers
- gas water heaters
- gas fireplaces and free standing stoves
- gas ranges
- automatic clothes washing machines
- dishwashers

At the national level, the Energy Efficiency Act (1995) regulated a broad range of energy-using appliances, although the vast majority were initially subject to testing and/or reporting requirements only, rather than minimum energy efficiency criteria. Energy efficiency standards have been also been enacted provincially by British Columbia, most recently under its Energy Efficiency Act (2008).

Exhibit 3.2: Summary of Energy Efficiency Standards by Appliance Type

Appliance	Energy Efficiency Standards
Gas furnaces of less than 225,000 Btu/hour	CSA P.2-07 Canada: February 3, 1995: minimum AFUE of 78%, all furnaces December 31, 2009: minimum AFUE of 90%, except thru-the-wall furnaces December 31, 2012: minimum AFUE of 90% for thru-the-wall furnaces British Columbia: January 1, 2008: minimum AFUE of 90% for new residential construction December 31, 2009: minimum AFUE of 90% for all furnaces – new construction or existing dwellings Energy Star Models Furnaces must have an AFUE rating of 90% or higher to qualify for Energy Star. April 1, 2007 to March 1, 2009: Energy Star qualified residential forced air furnaces or boilers (gas-fired and oil-fired), air source heat pumps and ground source heat pumps are eligible for a provincial tax exemption if purchased or leased for residential purposes.
Gas boilers with input rating of less than 300,000 Btu/hour	CGA P.2-1991 May 1, 1996: AFUE of 80% for hot water systems May 1, 1996: AFUE of 75% for low pressure steam systems
Gas water heaters with inputs of less than 75,000 Btu/h or less and storage capacity of 76 litres to 320 litres.	CAN/CSA P.3-04 September 1, 2004: Minimum efficiency factor (EF) of 0.67 – 0.0005V (where V=rated storage capacity in litres) Energy Star Models: Voluntary participation by manufacturers. Current Energy Star qualified models use 5% less energy than those meeting the minimum federal energy performance standard. January 1, 2009: minimum qualifying EF ≥ 0.62 and first hour rating (FHR) of ≥ 254 litres per hour for gas storage water heaters September 1, 2010: Gas tankless water heaters: EF ≥ 0.82, LPM ≥ 9.5 over 42.8°C rise Condensing gas storage water heater: EF ≥ 0.80, FHR ≥ 254 litres per hour Heat pump water heater: EF ≥ 2.0, FHR ≥ 190 litres per hour *continued next page…*

Appliance	Energy Efficiency Standards
Gas fireplaces including inserts and free standing stoves	CAN/CSA P.4.1-02 September 25, 2003: no minimum performance levels; regulations govern testing and reporting standards only. The Canadian Gas Fireplace Efficiency Standard, CGA-P.4, uses a laboratory procedure similar to the Annual Fuel Utilization Efficiency procedure for furnaces to measure the seasonal performance of gas fireplaces as they are normally installed in Canadian housing. This standard has already been utilized in British Columbia to determine eligibility for their Clean Choice Program, and it has resulted in P.4 efficiencies being developed for a large number of gas fireplaces.
Gas ranges	February 3, 1995: No minimum performance or test standards; regulations govern reporting only. No continuous burning pilot light if product has electrical power source
Clothes washers – top loading, front loading, and compact	CAN/CSA-C360-M89 CAN/CSA-C360-92 CAN/CSA-C360-03 British Columbia (testing only): May 1, 1991: E = 1.5 V + 30.5, where E=kWh/month and V= volume (litres) May 1, 1995: E = 1.5 V + 30.5, where E=kWh/month and V= volume (litres) Canada: May 1, 1995: testing and Energuide label January 1, 2004: • Vertical axis standard (45L or greater): minimum EF of 29.45 (Litres / kWh / cycle) • Horizontal axis: min EF of 29.45 January 1, 2007: • Vertical axis standard (45L or greater): minimum EF of 35.68 (Litres / kWh / cycle) • Horizontal axis: min EF of 35.68 • EnerGuide label required Energy Star Models: Voluntary participation by manufacturers. Current Energy Star qualified models are 36% more efficient than the minimum federal energy performance standard and use 35% to 50% less water. January 1, 2007: modified energy factor (MEF*) of at least 48.45 L/kWh/cycle (1.72 cu. ft./kWh/cycle) and maximum water factor (WF) = 1.07 L/cycle per L of tub capacity (8.0 gal./cycle/cu. ft.) January 1, 2009: MEF ≥ 1.8 cu. ft./kWh/cycle and WF ≤ 7.5 January 1, 2011: MEF ≥ 2.0 cu. ft./kWh/cycle and WF ≤ 6.0
Dishwashers – standard and compact	CAN/CSA-C373-92 CAN/CSA-C373-04 February 3, 1995: testing and Energuide label required January 1, 2004: minimum EF (energy factor = cycles per kilowatt hour) of 0.46 for standard dishwashers Energy Star Models: Voluntary participation by manufacturers. Current Energy Star qualified dishwashers must achieve energy efficiency levels at least 41% higher than the minimum regulated Canadian standard. Prior to 2007, ES models were required to be 25% more efficient than the standard at the time. *continued next page…*

Appliance	Energy Efficiency Standards
Dishwashers – standard and compact	January 1, 2007: minimum EF of 0.65 for standard dishwashers January 1, 2007: minimum EF of 0.65 for standard dishwashers August 11, 2009: maximum TEAC (kWh/yr) of 324, and maximum WF (Litres / cycle) of 21.96 January 1, 2011: maximum TEAC (kWh/yr) of 307, and maximum WF (Litres / cycle) of 18.93
Sources: Natural Resources Canada (http://oee.nrcan.gc.ca) *Energy Efficiency Act of British Columbia*, Energy Efficiency Standards Regulation, B.C. Reg. 389/93	

3.3.8 Demand-Side Management Initiatives

Demand-side management initiatives are programs run by utilities and/or governments that use financial incentives to encourage the adoption of energy efficient equipment and appliances, or behavioural-style programs that use education and awareness to encourage households to use energy more efficiently. Some are market transformation style programs which are designed to advance the market towards a specific energy efficiency target, with cooperation from municipal, provincial, and/or federal governments to legislate minimum efficiency standards to prevent the marketplace from retreating from the efficiency target. DSM programs directed at households in British Columbia are recognized as a contributing factor to the improvement of household energy efficiency.

A short list of DSM programs offered to residential customers for the purchase of energy efficient equipment and appliances that use natural gas either directly (e.g., gas furnaces) or indirectly (e.g., (hot water for dishwashers) includes:

- Terasen's Heating System Upgrade Program (2003, 2005-2007) - incentives to purchase high efficiency furnaces (AFUE of 90% or higher).
- Terasen Fireplace Upgrade Pilot Program (2004) – incentives to upgrade from decorative natural gas fireplaces to energy efficient heater-style fireplaces (efficiency of 55% or higher).

Initiatives pursued by BC Gas, included a furnace tune-up program, and a home weatherization and insulation program.

Other utilities, the Government of British Columbia, and the Government of Canada have, individually or in partnership, implemented market transformation programs to improve the energy efficiency standards for windows and appliances, including dishwashers and front loading clothes washing machines.

While assessing the collective impact of these programs on long-run trends in gas consumption is beyond the scope of this document, several areas of the 2008 REUS survey addressed the adoption of energy efficient equipment, and behaviours affecting the efficient use of energy.

3.3.9 Price Elasticities

The increase in the real price (nominal prices adjusted for inflation) of natural gas over the long-run is contributing to the decline in use rates.

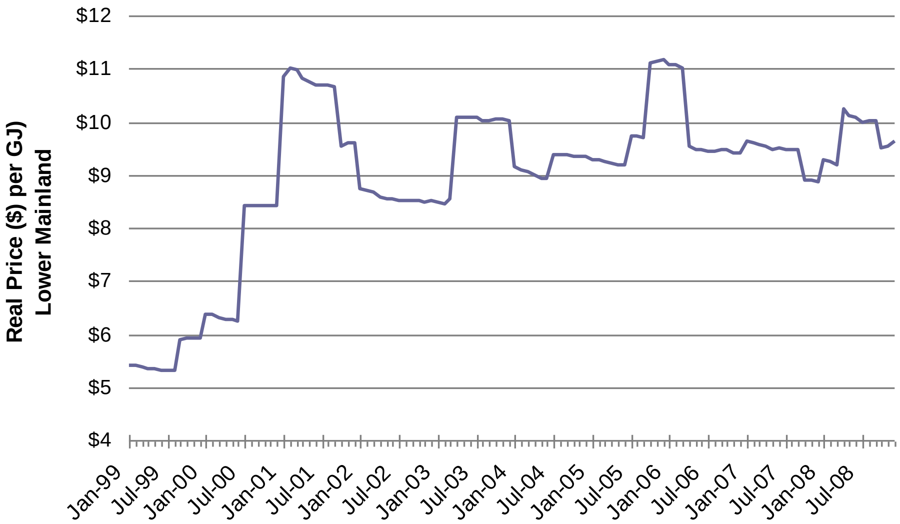
Figure 3.11 graphically illustrates the inflation-adjusted price of natural gas (variable rate component) for Terasen's LM residential customers from January 1999 to December 2008. The graph highlights the significant increase in prices in late 2000, and the volatility of prices during the subsequent period.[10]

[10] The variable rate portion of the Terasen tariff for residential customers reflects the price of natural gas purchased at prices set by the market and does not include any mark up.

Nominal prices have moved up and down during this period (20 adjustments) with 12 of the 20 adjustments representing price increases. As of end of 2008, inflation-adjusted prices were 10% higher than January 2002, and 78% higher than January 1999.[11] Price trends in the other regions have followed a similar trajectory.

Figure 3.11: Inflation-Adjusted Residential Natural Gas Prices

Variable Rate Portion ($/GJ) - Lower Mainland



Reactions to changes in natural gas prices differ in the short-term from the long-term. Estimates of short-term price elasticities for natural gas are generally quite low, in the order of -0.3 or smaller.[12] A 2006 study by the Colorado-based National Renewable Energy Laboratory (NREL) estimated the short-run price elasticity for natural gas in the Pacific Coast region of the U.S. (Washington and Oregon) to be -0.18 and the long-run price elasticity to be -0.63.[13]

Short-term reactions are mostly behavioural; increased thermostat set-backs, lowering of hot water temperatures, and increased use of alternative fuel space heating options (e.g., fireplaces, portable electric space heaters, etc.). Longer-term responses to price increases include sustained behavioural changes combined with structural changes, including improvements to the home’s thermal envelope (e.g., improved insulation, upgraded windows, etc.), upgrading to more efficient appliances (e.g., high efficiency furnaces, washing machines, dishwashers, etc.), and fuel switching (e.g., from gas to electric hot water heating, etc.).

The strength and nature of the reaction to price increases is also income dependent. The lack of financial resources means lower income households are less able to undertake the necessary structural improvements to reduce their exposure to higher energy prices than those with higher incomes. Their

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[11] Prices were adjusted for inflation using the consumer price index (CPI) for the Greater Vancouver areas. Data source: BC Stats.

[12] Interpreted as a 0.3% decline in gas consumption per every 1% increase in real prices. An overview of short- and long-term price elasticities for natural gas can be found in Wade, Steven, H., *Price Responsiveness in the AEO2003 NEMS Residential and Commercial Building Sector Models*, Energy Information Administration, U.S. Department of Energy.

[13] Bernstein, M.A., and Griffin, J., *Regional Differences in the Price-Elasticity of Demand for Energy*, Subcontract Report for National Renewable Energy Laboratory, NREL/SR-620-39512, February 2006.

adjustments to higher prices will be limited to low cost / no cost options (e.g., temporary plastic window coverings rather than window upgrades) or simply doing with less.

Of note, estimates of long-run price elasticity for natural gas are influenced by the fact that changes to building codes and other regulations have effectively altered the efficiency choices available to consumers. These changes, in the strictest sense, are not due to changes in consumer behaviours or actions per se. But unless specifically isolated, these underlying structural changes will be implicitly embedded in the size of the long-run price elasticity estimates.[14]

There is evidence that the short-term price elasticity for natural gas has remained stable despite the increase in prices in the current decade. The 2007 study by the American Gas Association found the price elasticity of residential natural gas demand has remained relatively constant since the 1990s. The study suggested that the decline in demand following the large percentage increase in prices since 2000 is explained by the price elasticity rather than an increased sensitivity or greater response by households to a given price change. In effect, the study's authors could not find evidence of an appreciable change in the short-run price elasticity of demand for natural gas in the post-2000 period.[15]

3.3.10 Cross Effects

Cross effects (also known as interaction effects) refer to the heating penalty associated with the adoption of energy efficient technologies that, due to their more efficient use of energy, produce less waste heat than their inefficient counterparts. As a result, space heating systems compensate, to some degree, for the lost heat. For homes with natural gas space heating, this lost heat represents an offsetting factor to declining use rates.

The displacement of incandescent lighting with compact fluorescent lighting is one example where the heating penalty may be significant. This is particularly relevant in British Columbia as the saturation of CFLs is approaching 7 CFLs per household.[16] The extent of the heating penalty is subject to considerable debate, and published estimates vary greatly.[17]

The need for replacement heat has also been identified with the increased penetration of variable speed motors with high efficiency condensing gas furnaces. Variable speed motors, known as electronically commutated motors (ECM), give off significantly less waste heat than their lesser-efficient fixed-speed counterparts.[18]

[14] A recent analysis commissioned by the American Gas Association approached this issue by estimating a price elasticity of -0.12 (US Pacific Census Division), separate from an annual trend reduction in demand of 1% for the adoption of efficient appliances (Source: Frederick Joutz and Robert P. Trost, *An Economic Analysis of Consumer Response to Natural Gas Prices*, AGA, March 2007, as referenced in the draft paper "Price Impact on the Demand for Water and Energy in California Residences", prepared for the California Energy Commission by the California Climate Change Center. March 2009).

[15] Climate Change Centre 2009.

[16] Calculated based on a penetration rate of 73% and an average of 9 CFLs per user-household. Data source: Tiedemann, K. and Sulyma, I., *Demand Side Management Milestone Evaluation Summary Report*, BC Hydro Power Smart Evaluation and Research, BC Hydro, report submitted to the British Columbia Utilities Commission, April 2008.

[17] For example, a 2004 study using Natural Resources Canada's test houses found that during the heating season, 80% to 96% of the energy savings from replacing incandescent lighting with CFLs was offset by the increased need for space heating. (Source: *Benchmarking of Energy Savings Associated with Energy Efficient Lighting in Houses,* Sustainable Buildings and Communities, CANMET Energy Technology Centre, Energy Technology and Programs Sector, April 20, 2004). In contrast, the Washington-based New Buildings Institute estimated the cross effects of lighting at 13% for the Pacific Northwest (Source: Advanced Lighting Guidelines: 2003 Edition, New Buildings Institute, Inc., Vancouver, WA).

[18] The operating temperature of a variable speed or ECM motor is constant and typically at or near ambient temperature, whereas the operating temperature of a fixed speed or PSC motor can range from 32 to 77 degrees Celsius.

4 BUILDING ENVELOPE & RENOVATIONS

This section summarizes the 2008 REUS results from the perspective of:

- building type, size, age, height (stories), tenure, and length of residency;
- building envelope characteristics including insulation levels for ceilings, walls, and basements, window types, and door types;
- presence and number of Energy Star qualified windows;
- renovation activity undertaken during the past five years, and planned for the next two years, by type of renovation; and
- who performs the renovations – homeowner, contractor, or a combination of the two.

4.1 Dwelling Characteristics

Single family detached dwellings are the predominant residential structure type, accounting for 83% of all TG customers in 2008 (Exhibit 4.1). SFDs accounted for 81% of all customers (respondents?) in 2002 and 85% in 1993, although all differences are within the margin of error for the estimates.

Notable differences in the composition of structure types in the five regions include proportionately more row houses and townhouses in the LM (10%) compared to TGVI (7%). And the INT (5%). Also, mobile homes and other dwellings are higher than the TG average in the INT and FN regions (5% and 18% respectively). Consistent with its resort nature, 53% of TGW's housing stock is comprised of row houses, townhouses, duplexes, or condominiums rather than single family detached dwellings.

Exhibit 4.1: Building Type (%)

Building Type	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	577	730	564	209	137	2217	1444	1610	4814
Single Family Detached	82.6	83.9	83.8	47.1	74.8	83.0	83.0	80.7	85.3
Duplex	4.8	5.0	6.0	15.3	2.2	5.0	4.9	4.5	3.0
Row / Townhouse	9.8	4.9	6.8	31.5	5.1	8.2	8.3	10.5	5.9
Apt / Condominium	0.9	1.5	1.2	5.1	--	1.1	1.0	0.4	0.7
Mobile Home / Other	1.9	4.7	2.2	0.9	17.9	2.7	2.8	3.8	5.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Exhibit 4.2 compares the classification of dwelling type, as indicated by survey respondents, with the three main building types as defined in Terasen's customer information system. Both methods of classifying the dwelling type may be subject to some degree of error. However, by default, it is assumed that survey respondents are best able to provide the most accurate categorization of their dwelling type.

The data indicate that 20% of TG accounts characterised as a VSD are row houses or townhouses, and another 3% and 4% are duplexes (semi-detached dwellings) or single family detached dwellings, respectively. For MFDs, 3% indicated they live in a single family detached dwelling, and 1% indicated their residence was either a mobile home or something other.

Exhibit 4.2: Classification of Building Type (%)

Building Type	SFD	VSD	MFD	2008 TG
Unweighted base	1368	242	607	2217
Single Family Detached	89.0	4.4	2.6	83.0
Duplex	3.8	3.3	22.5	5.0
Row / Townhouse	3.9	19.8	69.0	8.2
Apt / Condominium	0.5	72.5	5.1	1.1
Mobile Home / Other	2.9	0.0	0.8	2.7
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Exhibit 4.3 summarizes the age profile for residential dwellings in Terasen's five regions. Data for the 2002 and 1993 REUS studies are not provided as the age of the two studies makes comparison with the 2008 survey invalid.[19] Overall, 62% of TG customer housing stock was built prior to 1986, with 12% built prior to 1950, and 30% was built during 1950 to 1975. Nineteen percent (19%) of homes were built since 1995.[20] Regionally, TGVI and TGW are notable in having proportionately more homes built since 1995.

Exhibit 4.3: Age of Construction by Region (%)

Year of Construction	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	556	707	545	201	132	2141
Before 1950	12.2	7.3	17.2	0.5	3.0	12.2
1950-1975	29.6	25.6	23.5	7.1	27.6	29.6
1976-1985	20.3	22.5	9.7	6.5	29.1	20.3
1986 -1995	18.9	23.1	21.0	34.7	14.2	18.9
1996 -2005	18.0	19.4	26.6	47.8	21.0	18.0
2006 or later	0.7	0.9	1.6	2.5	2.2	0.7
DK	0.3	1.1	0.3	1.0	3.0	0.3
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Comparing the vintage of the housing stock by the three building types, yields some key differences (Exhibit 4.4). For example, the majority (92%) of VSDs were constructed since 1995, and majority (76%) of MFDs were constructed in the period since 1985.

[19] For example, the 1993 REUS includes only residences constructed prior to, or including 1993, and the 2002 REUS includes only dwellings constructed prior to, or including 2002. As the results are expressed as a percent of total residences, the differences in the base stock of housing affects the proportions in all other categories.

[20] The relative proportion of homes built since 2006 understates the true proportion because the REUS sample excludes residences with less than two years of uninterrupted billing history.

Exhibit 4.4: Age of Construction by Building Type (%)

Year of Construction	SFD	VSD	MFD	2008 TG
Unweighted base	1315	240	586	2141
Before 1950	11.9	0.7	3.5	11.3
1950-1975	29.2	0.0	9.8	27.8
1976-1985	20.5	1.1	10.4	19.8
1986 -1995	19.6	6.6	30.4	20.3
1996 -2005	17.6	66.4	41.2	19.3
2006 or later	0.6	25.0	3.8	0.9
DK	0.5	0.1	0.8	0.5
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

A very small percentage (1.5%) of respondents indicated the residence to which the survey was addressed was not their principal residence (Exhibit 4.5). This is comparable to results from 2002 and 1993 (1.6% and 0.8%). Regionally, 42% of TGW respondents indicated their residence was not their primary or principal residence. This latter result is consistent with the recreational resort nature of the community.

Exhibit 4.5: Principal Residence by Region (%)

Principal Residence?	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	578	730	566	209	138	2221	1446	1534	4776
Yes	99.0	97.9	97.8	58.1	98.5	98.5	98.7	98.3	99.2
No	1.0	2.1	2.2	41.9	1.5	1.5	1.3	1.6	0.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

There were no significant differences in principal residency proportions between the three building types (Exhibit 4.6).

Exhibit 4.6: Principal Residence by Building Type (%)

Principal Residence?	SFD	VSD	MFD	2008 TG
Unweighted base	1336	240	602	2178
Yes	98.5	97.7	98.0	98.5
No	1.5	2.3	2.0	1.5
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Renters made up 4.4% and 4.6% of TG and TGI customers respectively. The TGI percentage is down slightly from 6.6% in 2002 but the difference is not statistically significant at the 95% confidence interval. Regionally, the percentage of renters in the LM is significantly higher than TGVI, at the 95% confidence level. All other regional differences are not statistically significant.

Exhibit 4.7: Ownership Status by Region (%)

Building Type	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	575	728	563	209	136	2211	1439	1578	4780
Rent	5.2	3.4	2.2	4.2	4.4	4.4	4.6	6.6	6.7
Own	94.8	96.6	97.8	95.8	95.6	95.6	95.4	93.4	93.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Renters make up a significantly greater share of customers in MFDs (11%) compared to SFDs (4%) and VSDs (5%). These data are summarized in Exhibit 4.8.

Exhibit 4.8: Ownership Status by Building Type (%)

Principal Residence?	SFD	VSD	MFD	2008 TG
Unweighted base	1361	242	608	2211
Rent	3.9	5.2	10.9	4.4
Own	96.1	94.8	89.1	95.6
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

The average length of residence (i.e., number of years living in the same residence) for TG customers has increased to 15 years from 12 years in 2002 and 10 years in 1993 (Exhibit 4.9). This finding is consistent with the growing proportion of TG customers who are now in their middle to late-middle years (ages 45 to 64). Regionally, the LM has the highest average length of residence (16 years), while Whistler has the lowest (10 years).

Exhibit 4.9: Average Length of Residence (Years) by Region

Length of Residence (years)	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	570	714	556	205	135	2180	1419	1610	4814
Mean	16.0	13.8	14.3	10.3	11.3	15.2	15.0	12.4	10.4
Standard Deviation	12.9	11.1	11.2	8.2	9.7	12.3	12.4	11.7	n/a

The average number of years that TG customers resided in their residence varied significantly between the three building types (Exhibit 4.10). Residents of SFDs lived in their homes for an average of 16 years, significantly longer than the average of 5 years for those in VSDs and 9 years for those in MFDs. The considerably shorter length of residency for VSDs, and MFDs is consistent with the relatively young age of the VSDs and MFDs.

Exhibit 4.10: Average Length of Residence (Years) by Building Type

Length of Residence (years)	SFD	VSD	MFD	2008
Unweighted base	1334	240	607	2180
Mean	15.7	4.6	9.4	15.2
Standard Deviation	12.4	3.2	7.8	12.3

The shorter length of residency for VSDs and MFDs is also consistent with the relative popularity among younger home buyers. Exhibit 4.11 confirms that residents of VSDs and MFDs are significantly more likely to be under the age of 35 compared to residents of SFDs. These building types represent a more affordable option for younger, first time home buyers. VSDs and MFDs are also a popular choice of housing for customers aged 65 years or older, consistent with downsizing trends adopted during retirement years.

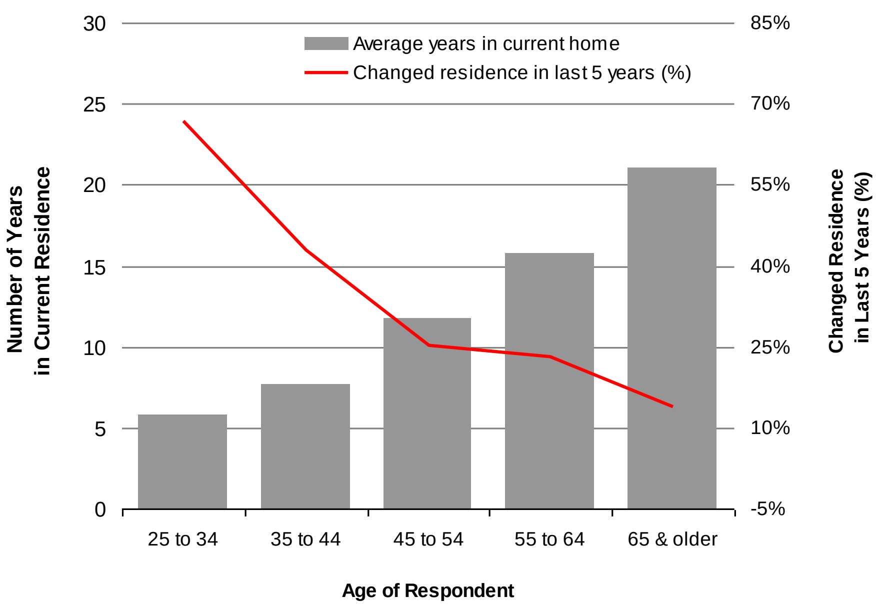
Exhibit 4.11: Age of Respondents by Building Type (%)

Age of Respondent (years)	SFD	VSD	MFD	2008
Unweighted base	1348	237	601	2186
24 yrs or less	0.4	0.7	0.5	0.4
25 to 34	3.8	15.3	9.1	4.2
35 to 44	13.5	17.4	16.1	13.7
45 to 54	20.7	17.1	15.8	20.4
55 to 64	29.5	19.3	21.1	28.9
65 & older	32.0	30.2	37.3	32.4
Total	100.0	100.0	100.0	100.0
34 yrs and younger	17.7	33.4	25.7	18.3
55 yrs and older	61.5	49.5	58.4	61.3

Totals may not sum due to rounding.

The likelihood of changing residences decreases as customers age (Figure 4.1). By the time customers reach the age of 65 years, they will have lived in their current home, on average, for 21 years compared to 12 years for customers aged 45 to 54 years. The likelihood of having changed residences in the last five years also decreases with age. For example, 23% of customers aged 55 to 64 years changed residences in the last five years compared to 43% of those aged 35 to 44 years.

Figure 4.1: Length of Residency by Age of Respondent



Overall, 15% of TG customers indicated they pay a monthly maintenance fee. These respondents were further queried as to what energy related end uses were covered by this monthly payment. End uses addressed included space heat, water heating, fireplace fuel, cooking fuel, and fuel for gas clothes drying. The results are summarized in Exhibit 4.12. The data in this table exclude DK responses, but these typically did not exceed 4% for any end use.

Exhibit 4.12: Rent / Maintenance Fees & End Uses Included by Region (%)

Maintenance Fee Details	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base[1]	261	239	165	99	5	769	505	1610	n/a
Pay monthly maintenance fee	16.2	12.0	13.6	48.6	4.3	14.9	14.9	14.3	n/a
Fee includes space heat	6.7	14.5	11.3	7.2	12.3	8.5	8.2	2.1	n/a
Fee includes water heating	8.5	21.4	13.3	8.3	12.3	11.3	11.2	3.0	n/a
Fee includes fireplace fuel	6.6	6.8	8.7	7.2	12.3	6.8	6.6	1.9	n/a
Fee includes fuel for cooking	2.9	3.7	0.3	2.1	22.0	2.8	3.1	n/a	n/a
Fee includes fuel for gas clothes drying	4.1	0.3	0.6	3.1	11.0	3.2	3.4	n/a	n/a

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Water heating and space heat were the two end uses most frequently covered by a maintenance fee, as indicated by 11% and 9% of respondents, respectively. Fuel for the fireplace was the next most common expense covered by the monthly charge (7%).

End uses covered by maintenance fees by building type are summarized in Exhibit 4.13. Of note, 90% of VSD residents and 76% of MFD residents pay a monthly maintenance fee.

Exhibit 4.13: Rent / Maintenance Fees & End Uses Included by Building Type (%)

Maintenance Fee Details	SFD	VSD	MFD	2008
Unweighted base	140	214	415	769
Pay monthly maintenance fee	9.7	89.9	75.7	14.9
Fee includes space heat	11.8	12.2	1.9	8.5
Fee includes water heating	13.5	46.5	4.4	11.3
Fee includes fireplace fuel	9.4	5.9	1.9	6.8
Fee includes fuel for cooking	3.3	5.7	1.9	2.8
Fee includes fuel for gas clothes drying	4.8	1.0	0.3	3.2

Totals may not sum due to rounding.

4.2 Size of Residence

Respondents to the 2008 REUS were asked to indicate the total floor area of their residence including the basement and/or any unfinished areas, but excluding garages or carports. As the results included a small number of responses considered unrealistically high or low, an outlier analysis was used to remove the bottom 0.5% and top 0.5% of the estimates, ranked from lowest to highest. This affected only 1% of the unweighted sample.

The average size (square feet) of TG customer homes is 2,220 square feet (Exhibit 4.14). Differences between the means for 2002 and 1993 surveys are not statistically significant at the 95% confidence level.

Exhibit 4.14: Size of Residence by Region (Mean Square Feet)

Floor Area in Square Feet	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	529	653	522	197	123	2044	1305	1416	4364
Mean [1]	2280	2148	2058	2186	1839	2220	2239	2199	2107
Standard Deviation	1187	806	489	176	147	806	950 [2]	950 [3]	n/a

[1] Mean calculated excluding the top 0.5% largest and smallest values (n=22)
[2] The standard deviation of 949.9.
[3] Standard deviation of 949.8.

The trend towards larger houses is evident in Exhibit 4.15 which shows the average square footage of homes built in the 1986 to 2005 period to be 15% to 17% larger than those built in years prior. The decline in square footage of homes built in 2006 or later relative to homes constructed in the 1996 to 2005 period is not statistically significant.

Exhibit 4.15: Size of Dwellings by Construction Date – Single Family Detached

Floor Area in Square Feet	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known	2008 TG
Unweighted base[1]	123	276	201	221	230	12	6	1069
Mean [2]	2219	2127	2246	2628	2572	2382	1953	2330
Standard Deviation	961	906	817	1057	1007	472	820	970

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Mean calculated excluding the top 0.5% largest and smallest values.

Exhibit 4.16 compares the average size of residential dwellings for each of the five TG regions, by the three building types – SFDs, VSDs, and MFDs. As expected, VSDs, regardless of region, were smaller in size than SFDs (1291 ft^2 versus 2263 ft^2). MFDs averaged 1,672 square feet.

Exhibit 4.16: Size of Residence by Building Type and Region (Mean Square Feet)

Floor Area in Square Feet [1]	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	529	653	522	197	123	2024
SFD	2338	2169	2084	2520	1839	2263
VSD	1253	1348	**	--	--	1291
MFD	1699	1596	1553	1583	**	1672
All building types	2280	2148	2058	2186	1839	2220

[1] Mean calculated excluding the 0.5% largest and smallest values (n=22)
** Sample size too small to report estimate.

4.2.1 Number of Stories – Apartments / Condominiums

Exhibit 4.17 summarizes the data on the number of stories for apartments / condominiums excluding levels used for retail or parking. The majority (59%) of respondents living in apartments / condominiums live in buildings with three stories or less. Another 35% live in structures with four to nine floors. The remaining 6% live in buildings with ten stories or more. The number of stories excludes levels used only for parking or retail.

Exhibit 4.17: Number of Stories – Apartments / Condominiums

Number of Stories	VSDs
Unweighted base	240
3 or less	58.9
4 to 9	35.3
10 to 14	2.8
15 or more	3.1
Total	100.0
Mean	3.9
Standard deviation	1.2

Totals may not sum due to rounding.

4.3 Number of Stories - Residence

The 2008 survey asked respondents to indicate the number of stories above ground for their residence, excluding the basement. This question has been worded somewhat differently in each of the three surveys as the categorization of basements as either a true “story” in the house is somewhat problematic because some respondents consider the first floor of their home as the basement, although it may be fully above ground.[21] Accurately categorizing an above ground basement as a true “story” in the house is necessary for analyses involving the building envelope and the heating requirements of the structure. It also ensures consistency with past REUS studies.

A review of the 2008 REUS results revealed that a number of respondents indicated they had a completely above ground basement. As the question regarding the number of stories in the dwelling asked respondents to exclude basements, the number of “above ground” stories for these respondents was increased by one story to include the basement. Exhibit 4.18 summarizes the results by region and compares them to the 2002 and 1993 survey results.

Exhibit 4.18: Number of Stories Above Ground by Region Excluding Below Ground (Partial or Full) Basements (%)

Number of Stories	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	532	680	533	199	128	2072	1340	1555	4665
One story [1]	37.1	63.9	53.7	7.3	81.5	46.1	45.3	35.9	44.2
Two stories	52.9	32.4	37.2	58.3	17.8	45.7	46.6	51.6	49.4
Three stories	9.2	3.4	8.3	29.9	0.8	7.5	7.4	11.3	5.7
More than three stories	0.9	0.2	0.8	4.5	0.0	0.7	0.7	1.1	0.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mean	1.7	1.4	1.6	2.3	1.2	1.6	1.6	1.8	1.6
Standard deviation	1.0	0.5	0.4	0.1	0.1	0.7	0.6	1.1	n/a

[1] Includes below ground or “garden level” apartments (2008 data only).
Totals may not sum due to rounding.

The average number of stories per dwelling, excluding partially or fully below ground basements, varies by region. Single story homes are most common in FN (82%), INT (64%) and TGVI (54%). TGW and LM have proportionately more homes with two stories or more.

The number of stories also varies by building type, with VSDs significantly more likely to have only one story compared to SFDs and MFDs (Exhibit 4.19).

[21] The categorization of the first floor of a house as the “basement” is particular to Lower Mainland respondents, and is likely associated with the popularity of some residential building types (e.g., “Vancouver Specials”).

Exhibit 4.19: Number of Stories Above Ground by Building Type Excluding Below Ground (Partial or Full) Basements (%)

Number of Stories	SFD	VSD	MFD	2008 TG
Unweighted base	1281	227	564	2072
One story [1]	47.3	63.8	27.3	46.1
Two stories	45.1	23.6	55.8	45.7
Three stories	7.0	10.7	14.7	7.5
More than three stories	0.6	1.7	2.1	0.7
Total	100.0	100.0	100.0	100.0
Mean	1.6	1.6	1.8	1.6
Standard deviation	0.5	0.1	0.2	0.7

[1] Includes below ground or "garden level" apartments (2008 data only).
Totals may not sum due to rounding.

4.3.1 Basements and Crawlspaces

Basements or crawlspaces were present in 79% of all TG customer residences (Exhibit 4.20). Crawlspaces were more common in the TGVI and TGW regions (26% and 34% respectively). Basements, if present, were detailed by whether they were completely above ground, completely below ground, or partially above ground. Due to differences in question wording between the 2008 REUS surveys, data for 2002 and 1993 are not comparable and are not reported.

Exhibit 4.20: Incidence of Basements and Crawlspaces by Region (%)

Basement Details	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	545	679	544	207	133	2108
No Basement	24.9	11.0	22.2	31.3	31.1	20.8
Partial	11.5	13.3	13.5	19.7	8.1	12.2
Full	48.2	65.8	37.9	14.6	54.1	52.0
Crawlspace	15.4	9.8	26.4	34.4	6.7	15.0
Total	100.0	100.0	100.0	100.0	100.0	100.0
Basement or crawlspace	75.1	88.9	77.8	68.7	68.9	79.2

Totals may not sum due to rounding.

Exhibit 4.21 shows that SFDs were most likely to have a basement or crawlspace (81%), compared to VSDs (21%), and MFDs (57%). The numbers confirm that some dwellings classified as VSDs do not strictly adhere to the convention of stacked apartment style units.

Exhibit 4.21: Incidence of Basements by Building Type (%)

Basement Details	SFD	VSD	MFD	2008 TG
Unweighted base	1321	203	584	2108
No Basement	19.0	79.1	42.7	20.8
Partial	12.2	4.7	12.3	12.2
Full	53.5	14.5	31.6	52.0
Crawlspace	15.2	1.6	13.4	15.0
Total	100.0	100.0	100.0	100.0
Basement or crawlspace	80.9	20.8	57.3	79.2

Totals may not sum due to rounding.

The level of finishing for homes with basements are summarized in Exhibit 4.22. The percentage of TGI homes with finished basements has risen from 35% in 1993 to 44% in 2008.

Exhibit 4.22: Basement Finishing (%) by Region

Basement Details	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	476	583	380	134	123	1696	1182	1549	4621
No basement [1]	30.0	12.5	30.5	48.6	33.3	25.0	24.4	29.7	29.0
Unfinished basement	4.8	9.9	10.0	14.3	4.4	6.7	6.4	7.6	9.4
Partially finished basement	21.8	32.0	27.8	11.4	24.4	25.3	25.1	22.8	27.2
Completely finished basement	43.4	45.6	31.7	25.7	37.8	43.0	44.1	39.9	34.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] 1993 and 2002 data includes basements and crawlspaces
Totals may not sum due to rounding.

Seventy-four percent (74%) of respondents with basements or crawlspaces indicated they are heated during the heating season (Exhibit 4.23). FN customers were significantly more likely to heat their basement / crawlspace (95%) than the other four regions. TGVI customers were significantly less likely to heat their basement / crawlspace (65%) than LM (73%), INT (80%) and FN (95%) customers.

Exhibit 4.23: Heating of Basement or Crawlspace by Region (%)

Basement / Crawlspace Heating	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	324	521	397	142	89	1473
Usually heated during heating season	73.0	79.7	64.7	72.5	94.5	74.2
Not heated	27.0	20.3	35.3	27.5	5.5	25.8
Total	100.0	100.0	100.0	100.0	100.0	100.0

[1] Excludes homes without basements
Totals may not sum due to rounding.

Exhibit 4.24 shows that heating of the basement / crawlspace is significantly less common for customers living in VSDs (49%) versus SFDs and MFDs (75% and 70% respectively). The presence of a basement or crawlspace in VSDs is somewhat surprising. However, some respondents categorized as living in a VSD by Terasen's Customer Information System (CIS) indicated their dwelling was something other than a condominium or apartment, meaning that the presence of a basement or crawlspace may be legitimate. Another explanation may be that some respondents living in apartments /condominiums may have interpreted this question as referring to the basement (common) area of their building rather than their unit.

Exhibit 4.24: Heating of Basement or Crawlspace by Building Type (%)

Basement / Crawlspace Heating	SFD	VSD	MFD	2008 TG
Unweighted base [1]	1044	52	377	1473
Usually heated during heating season	74.5	49.2	70.3	74.2
Not heated	25.5	50.8	29.7	25.8
Total	100.0	100.0	100.0	100.0

[1] Excludes homes without basements
Totals may not sum due to rounding.

4.4 Ceiling Heights

Ceiling heights affect the total volume of the home required to be heated. Respondents were asked to indicate the proportion of their residence with 8, 9, 10 and more than 10 foot ceiling heights. Exhibit 4.25 shows that 8 foot ceilings are most common, accounting for 72% of all ceilings in a typical residence. Nine foot ceilings account for 18% of all ceilings of TG customers. Regionally, dwellings in TGW tend to have a higher incidence of nine and ten foot ceilings (23% and 11%) compared to regions outside of the Lower Mainland.

Exhibit 4.25: Ceiling Heights by Region
Percent of the Residence [1]

Ceiling Height	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	496	627	501	204	124	1952
8 feet	70.7	74.9	70.2	45.3	80.5	71.8
9 feet	18.0	16.4	17.3	23.3	13.0	17.5
10 feet	6.9	5.1	7.6	10.6	4.4	6.5
More than 10 feet	4.2	3.3	4.2	20.8	1.5	4.0

[1] Mean percentage of respondent answers by region

Exhibit 4.28 shows that ceiling heights have been increasing among homes built since the mid-1980s. Eight foot ceilings were most common among dwellings constructed prior to 1985. Since then, the trend has been towards 9 foot ceilings.

Exhibit 4.26: Ceiling Heights by Dwelling Construction Date
Mean Percentages

Ceiling Height	Before 1950	1950 - 1975	1976 - 1985	1986 – 1995	1996 - 2005	2006 or later	Age Un-known	2008 TG
Unweighted base [1]	144	340	249	427	630	86	19	1952 [2]
8 feet	71.0	81.1	84.6	70.1	49.9	32.7	80.2	71.8
9 feet	18.6	8.4	7.0	19.6	35.4	55.2	11.5	17.5
10 feet	4.4	7.3	5.0	5.7	9.0	6.2	7.9	6.5
More than 10 feet	5.6	2.6	3.3	4.5	5.4	4.3	0.4	4.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only
[2] TG means include ceiling height data for 57 respondents that did not answer the dwelling age question.

Data on ceiling heights by the three building types are summarized in Exhibit 4.27. VSDs are significantly more likely to have ceilings higher than 8 feet than SFDs and MFDs.

Exhibit 4.27: Ceiling Heights by Building Type
Mean Percentages

Ceiling Height	SFD	VSD	MFD	2008 TG
Unweighted base	1229	199	524	1952
8 feet	72.7	30.4	60.0	71.8
9 feet	17.0	38.2	23.8	17.5
10 feet	6.1	21.0	10.9	6.5
More than 10 feet	3.9	10.1	5.1	4.0

4.5 Insulation Levels

Respondents were asked to rate the insulation level in their residence's ceiling / attic, walls, and basement (if present) in the 2008 and 2002 surveys. The 1993 survey did not query insulation levels. Three levels of insulation were defined for each:

- Less than average (about R6 or 1.75 inches of insulation or less)
- Average (about R12 or 3.5 inches of insulation)
- More than average (about R18 or 5.25 inches of insulation or more)

Insulation levels in the ceiling or attic are summarized by region in Exhibit 4.28. Compared to 2002, the proportion of homes with above average insulation has increased. This is consistent with the fact that the 2008 study includes newer homes (i.e., those built since 2002) that are better insulated. Of note, the percentage of respondents who were unsure varied from 13% to 29% depending upon the region, and averaged 20% overall. This level of uncertainty regarding ceiling / attic insulation levels is comparable to the 2002 survey. This response category was included in the presentation of the results because it cannot be assumed that DK responses are proportionately distributed among those who indicated one of the three insulation levels.

Exhibit 4.28: Ceiling / Attic Insulation Levels by Region (%)

Insulation Rating	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	538	663	534	204	127	2066	1328	1610
Less than average	5.5	4.3	6.1	4.4	7.7	5.2	5.1	6.5
Average	40.1	33.1	44.0	27.0	38.7	38.6	38.0	40.7
More than average	32.5	43.6	37.3	39.5	39.5	36.0	35.8	31.1
DK	22.0	19.1	12.6	29.1	14.0	20.3	21.1	21.8 [1]
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] May include missing values

Ceiling / attic insulation levels by building type are provided in Exhibit 4.29. Due to the structure characteristics of VSDs, comparisons of ceiling / attic insulation levels are only valid for SFDs versus MFDs. This is confirmed by the large percentage of VSD residents who were unsure of their insulation level.

Exhibit 4.29: Ceiling / Attic Insulation Levels by Building Type (%)

Insulation Rating	SFD	VSD	MFD	2008 TG
Unweighted base	1316	187	563	2066
Less than average	5.1	0.5	7.5	5.2
Average	38.9	18.2	35.2	38.6
More than average	37.2	15.8	19.3	36.0
DK	18.9	65.4	38.0	20.3
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

As expected older homes tend to have less than average insulation in their ceiling / attic while newer homes tend to be better insulated (Exhibit 4.30). This relationship was observed in the 2002 REUS study as well.

Exhibit 4.30: Ceiling / Attic Insulation Levels by Dwelling Construction Date (%)

Insulation Rating	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known	2008 TG
Unweighted base[1]	158	363	273	454	646	86	20	2000
Less than average	16.8	7.1	1.4	2.4	0.5	0.0	42.8	5.0
Average	43.8	39.6	40.0	40.3	33.3	16.6	8.6	38.8
More than average	27.3	36.7	41.2	38.4	33.2	33.6	1.2	36.0
DK	12.1	16.6	17.4	18.9	33.0	49.7	47.4	20.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

The level of wall insulation, by region, is summarized in Exhibit 4.31. On average, 54% of TG customers rated the insulation in their walls as average, and 14% rated it as above average.

Exhibit 4.31: Wall Insulation Levels by Region (%)

Insulation Rating	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	534	665	530	201	132	2062	1331	1610
Less than average	12.9	9.0	7.8	3.4	8.2	11.3	11.7	11.7
Average	55.3	51.8	53.9	35.9	54.4	54.2	54.3	47.5
More than average	10.1	21.4	19.5	31.6	24.6	14.2	13.6	11.2
DK	21.7	17.7	18.7	29.1	12.8	20.3	20.5	29.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Wall insulation levels by building type are summarized in Exhibit 4.32. Overall, 55% of respondents in SFDs rated their insulation level as average, and 11% rated it as below average. Responses from respondents in VSDs and MFDs are difficult to compare as a significant percentage of each indicated they did not know their wall insulation level.

Exhibit 4.32: Wall Insulation Levels by Building Type (%)

Insulation Rating	SFD	VSD	MFD	2008 TG
Unweighted base	1310	212	540	2062
Less than average	11.5	1.6	8.4	11.3
Average	54.9	27.8	44.6	54.2
More than average	14.5	16.2	10.1	14.2
DK	19.1	54.4	36.8	20.3
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

As was the case with ceiling / attic insulation levels, wall insulation levels improve with newness of dwelling, with only 10% of respondents indicating that their pre-1950 home had above average wall insulation, versus 25% of those living in homes built between 1996 and 2005. The results by dwelling age are summarized in Exhibit 4.33.

Exhibit 4.33: Wall Insulation by Dwelling Construction Date (%)

Insulation Rating	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known	2008 TG
Unweighted base[1]	154	360	274	445	652	93	18	1996
Less than average	30.2	19.5	5.9	1.8	3.3	0.4	15.0	11.2
Average	44.8	56.9	67.5	55.6	41.4	28.3	60.0	54.2
More than average	9.8	6.5	8.4	24.5	25.0	21.7	--	14.5
DK	15.2	17.1	18.1	18.1	30.4	49.6	25.0	20.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Basements can be a major source of heat loss if not insulated, accounting for 20% to 35% of the total heat loss of a house.[22] Insulation levels for basements, by region, are summarized in Exhibit 4.34. Respondents in TGW and FN were more likely to rate their basement insulation levels as more than average compared to the other regions. Overall, 50% of TG customers with basements rated the insulation in their basements as average.

Exhibit 4.34: Basement Insulation by Region (%)
Dwellings with basements

Insulation Rating	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	290	466	312	114	80	1262	836	1610
Less than average	14.5	14.7	19.0	6.0	14.7	14.8	14.6	11.7
Average	50.6	48.7	46.0	36.0	45.0	49.6	49.9	35.5
More than average	11.7	18.4	17.7	24.9	24.4	14.4	14.0	8.5
DK	23.2	18.2	17.4	33.0	15.9	21.1	21.5	44.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Data on basement insulation by building type is summarized in Exhibit 4.35.

Exhibit 4.35: Basement Insulation by Building Type (%)

Insulation Rating	SFD	VSD	MFD	2008 TG
Unweighted base	925	38	299	1262
Less than average	15.1	12.0	12.4	14.8
Average	49.9	19.6	45.2	49.6
More than average	14.7	23.4	8.9	14.4
DK	20.4	45.1	33.5	21.1
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Basement insulation by age of the dwelling is summarized Exhibit 4.36. The data show that basements in newer homes are more likely to insulated, and better insulated.

[22] Natural Resources Canada, *Keeping the Heat In – EnerGuide*, 2004.

Exhibit 4.36: Basement Insulation by Dwelling Construction Date (%)

Insulation Rating	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known	2008 TG
Unweighted base[1]	133	294	193	239	318	32	11	1220
Less than average	33.1	21.5	6.9	6.8	4.2	0.5	8.6	14.8
Average	40.2	47.6	60.9	53.5	45.9	20.1	41.0	49.6
More than average	11.4	10.4	11.6	20.5	23.3	24.5	--	14.7
DK	15.2	20.5	20.6	19.3	26.5	54.9	50.4	20.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

4.6 Windows

Survey respondents were asked to describe the windows in their residence by the number of panes (glazing), the presence of low emissivity (low-e) coating. They were asked to indicate the percentage of their windows that matched the following descriptions:

- Single pane regular glass
- Double pane regular glass
- Double pane with low-e coat
- Triple pane regular glass
- Triple pane with low-e coat
- Other

Additionally, for double and triple glazed windows, respondents were asked to indicate the presence of argon gas fill between the glazing. With the exception of the presence of argon gas, these window descriptions match those used in 2002. However, the 2002 survey did not ask for percentages but rather that the respondent indicate which of the window types were in the majority of window openings, preventing direct comparison with the 2008 data.

Exhibit 4.37 summarizes the mean percentages for the five window types and “other”. Double pane regular glass windows represent 66% of TG customer windows, with Lower Mainland customers significantly more likely to have single pane windows than customers in other regions. Triple pane windows, with or without low-e coatings, represent a very small percentage of windows, regardless of region.

Exhibit 4.37: Window Glazing by Region (Mean %)

Window Type	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	523	645	509	194	122	1993
Single pane regular glass	22.5	10.3	13.7	3.4	8.6	18.2
Double pane regular glass	64.1	70.0	69.3	76.4	62.2	66.3
Double pane with low-e coat	11.3	18.0	15.0	18.1	27.1	13.5
Triple pane regular glass	0.4	0.5	0.5	0.4	0.1	0.5
Triple pane with low-e coat	0.4	0.2	0.3	1.1	0.8	0.4
Other	0.8	0.7	0.5	0.8	--	0.7

Columns do not sum to 100% because of multiple responses

Data on window types by home vintage are shown in Exhibit 4.38. They show that while double paned windows are the predominant window choice for all homes regardless of vintage, single pane windows are more common among older homes. The use of low-e coatings on either double or triple glazed windows is highest among homes constructed since 2005, but the data suggests that some degree of window replacement using more efficient windows has occurred across the stock of housing.

Exhibit 4.38: Window Glazing by Dwelling Construction Date (Mean %)

Window Type	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 – 2005	2006 or later	Age Un-known	2008 TG
Unweighted base[1]	152	356	260	439	654	87	20	1968
Single pane regular glass	41.8	28.6	13.8	8.3	1.8	1.1	10.1	18.2
Double pane regular glass	45.4	52.6	70.8	80.8	81.7	61.3	78.7	66.3
Double pane with low-e coat	11.6	16.0	13.8	9.4	15.4	36.0	11.2	13.5
Triple pane regular glass	0.0*	1.1	0.7	0.0*	0.1	--	--	0.5
Triple pane with low-e coat	0.0	0.2	1.1	0.2	0.2	0.6	--	0.4
Other	0.3	1.0	0.0*	0.3	0.7	1.0	--	0.7

Columns do not sum to 100% because of multiple responses
* Value less than 0.1%
1 Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Exhibit 4.39 summarizes the windows data by building type. The percentage of windows that are single pane is significantly lower for VSDs which is consistent with their relative newness. SFDs and VSDs were significantly more likely than MFDs to have double pane windows with low-e coatings.

Exhibit 4.39: Window Glazing by Building Type (Mean %)

Window Type	SFD	VSD	MFD	2008 TG
Unweighted base	1249	204	540	1993
Single pane regular glass	18.4	8.4	16.6	18.2
Double pane regular glass	65.6	67.4	74.9	66.3
Double pane with low-e coat	14.0	18.9	6.1	13.5
Triple pane regular glass	0.5	0.2	0.1	0.5
Triple pane with low-e coat	0.3	1.9	0.6	0.4
Other	0.7	2.7	0.6	0.7

Columns do not sum to 100% because of multiple responses

The presence of argon gas fill in double or triple glazed windows is summarized in Exhibit 4.40. There is a much higher incidence of argon gas fills with windows that have a low-e coating than those without. For example, 8% of respondents indicated their double paned windows were equipped with argon gas compared to 52% of respondents with double paned windows that had a low-e coating.

Exhibit 4.40: Argon Gas Fill by Window Type (%)
Share across

Window Type	Yes	No	DK	Total	Un-weighted Base[1]
Double pane regular glass	7.5	43.1	49.4	100.0	1331
Double pane with low-e coat	51.6	13.6	34.7	100.0	389
Triple pane regular glass	5.5	12.8	81.7	100.0	9
Triple pane with low-e coat	28.3	0.0	71.7	100.0	17
Other	10.3	17.3	72.4	100.0	18

1 Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

Respondents were asked to indicate what percentage of their windows, by window type, were Energy Star qualified. Energy Star windows are a relatively new standard for the windows market (within the last three years). As a result, the proportions were expected to be low. However, 18% of TG customers indicated they have at least one window in their home that is Energy Star qualified (Exhibit 4.41). This proportion is surprisingly high. It is possible that some respondents generalized that their energy efficient windows were, by default, Energy Star. The high proportion of respondents that indicated they were uncertain as to whether any of their windows were Energy Star qualified (anywhere from 35% to 49%, depending upon the region) also suggests that there is considerable uncertainty embedded in the Energy Star qualified window estimates. As a result, they should be interpreted with caution.

Exhibit 4.41: Energy Star Qualified Windows by Region (%)

Percentage	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	559	706	551	204	133	2153
0%	47.6	43.8	37.1	37.7	42.9	45.5
1% - 25%	1.4	3.9	3.5	1.0	4.4	2.3
26% - 50%	1.7	3.6	2.4	1.5	2.2	2.3
51% - 75%	3.0	2.9	2.7	1.0	0.7	3.0
76% - 100%	10.9	9.3	10.6	9.8	8.9	10.4
DK/NR	35.4	36.5	43.7	49.0	40.8	36.6
Some or all Energy Star Windows	**17.0**	**19.7**	**19.2**	**13.3**	**16.2**	**18.0**

Columns do not sum to 100% because of multiple responses

4.7 Doors

Exhibit 4.42 summarizes the relative penetration of outside doors by door type and material, by the five TG regions. Thirty-four percent (34%) of all outside doors are insulated steel or fibreglass. The next most common are standard wood doors (27%). Regionally, INT and FN customers were significantly more likely to have insulated steel or fibreglass doors than other regions.

Exhibit 4.42: Outside Doors by Region (% of all Doors)

Outside Door Type	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	535	671	534	203	131	2074
Standard wood doors	32.1	16.0	25.0	29.1	11.1	27.2
Standard wood doors with aluminium storm doors	7.2	8.7	8.2	2.6	13.1	7.7
Insulated steel or fibreglass doors	29.5	44.0	34.4	12.0	54.0	33.8
Glass doors with wooden frames	7.4	10.8	8.9	27.3	7.0	8.5
Glass doors with aluminium frames	19.3	10.8	15.1	23.4	8.6	16.7
Glass doors with vinyl frames	4.5	9.7	8.3	5.7	6.1	6.2
Total	100.0	100.0	100.0	100.0	100.0	100.0

Exhibit 4.43 summarizes the distribution of door types by dwelling type.

Exhibit 4.43: Outside Doors by Dwelling Type (% of all Doors)

Outside Door Type	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other	Total
Unweighted base [1]	1140	209	429	232	48	14	2074
Standard wood doors	28.2	26.9	20.6	40.6	21.3	2.9	27.2
Standard wood doors with aluminium storm doors	7.9	4.1	6.9	2.7	17.0	1.9	7.7
Insulated steel or fibreglass doors	33.9	32.7	27.1	11.9	43.7	55.3	33.8
Glass doors with wooden frames	8.5	13.5	6.4	7.4	4.4	6.1	8.5
Glass doors with aluminium frames	15.3	14.5	32.2	30.8	10.7	33.8	16.7
Glass doors with vinyl frames	6.3	8.3	6.8	6.6	2.9	0.0	6.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Exhibit 4.44 presents the data on outside doors in terms of the average number of outside doors per residence, by door material. Regional differences are apparent, with LM and TGW dwellings having a larger number of wood doors per dwelling compared to the other regions. These data are influenced both by regional differences in the mix of dwelling types, construction characteristics, and the average age of the housing stock. The average number of outside doors per dwelling varies from a low of 2.7 in FN to 3.9 in TGW. The overall TG average was 3.6 outside doors, on average, per dwelling.

Exhibit 4.44: Outside Doors (Average Number per Residence)

Outside Door Type	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	535	671	534	203	131	2074
Standard wood doors	1.2	0.5	0.9	1.3	0.3	1.0
Standard wood doors with aluminium storm doors	0.3	0.3	0.3	0.1	0.4	0.3
Insulated steel or fibreglass doors	1.1	1.5	1.2	0.5	1.5	1.2
Glass doors with wooden frames	0.3	0.4	0.3	1.2	0.2	0.3
Glass doors with aluminium frames	0.7	0.4	0.5	1.0	0.2	0.6
Glass doors with vinyl frames	0.2	0.3	0.3	0.2	0.2	0.2
Average # per residence (all door types)	**3.7**	**3.4**	**3.6**	**3.9**	**2.7**	**3.6**

The relative popularity of outside doors by door type depends, in part, on the age of the residence. For example, older homes are more likely to have at least one standard wood door, either on their own or combined with an aluminium storm door (Exhibit 4.45). Newer homes are more likely to have insulated steel or fibreglass doors. Glass doors with aluminium frames, typically a patio door style, became popular with homes constructed during the 1970s and 1980s but appear to have been supplanted to some degree by styles using either wood or vinyl frames.

Exhibit 4.45: Outside Doors by Dwelling Construction Date (%) – Incidence (at least one)

Outside Door Type	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 – 2005	2006 or later	Age Un-known	2008 TG
Unweighted base	154	366	270	446	661	95	19	2011
Standard wood doors	80.2	61.5	51.8	28.4	22.8	36.9	56.2	47.4
Standard wood doors with aluminium storm doors	20.4	23.1	19.4	13.4	7.2	4.1	25.0	16.9
Insulated steel or fibreglass doors	41.7	49.3	56.4	68.2	71.5	52.7	18.8	57.7
Glass doors with wooden frames	15.6	12.9	10.8	23.6	17.4	36.4	0.9	15.9
Glass doors with aluminium frames	6.8	34.2	44.2	39.4	31.4	22.1	39.8	33.5
Glass doors with vinyl frames	5.9	13.3	17.8	15.3	22.0	19.6	12.9	15.4
Average # per residence (all door types)	**3.4**	**3.6**	**3.6**	**3.7**	**3.7**	**3.5**	**2.7**	**3.6**

Columns do not sum to 100% because of multiple responses

4.8 Renovations

Respondents were provided a list of specific renovations related to energy use and asked to indicate whether they had been undertaken at the residence in the last five years. For each renovation, with a couple of exceptions, respondents were asked to indicate whether they undertook the renovation themselves, used a contractor, or a combination of themselves and a contractor.

Data on renovation activity during the last five years are summarized in Exhibit 4.46. The top three activities, ranked by frequency of mention, include purchasing energy efficient appliances (37% of all respondents), installing weather stripping or caulking (21%), and installing a low flow showerhead (19%). Of note, 18% of respondents installed a programmable thermostat. As expected, renovations that were not overly complex (e.g., installing a low flow showerhead or installing weather stripping) were generally performed by the individual rather than a contractor.

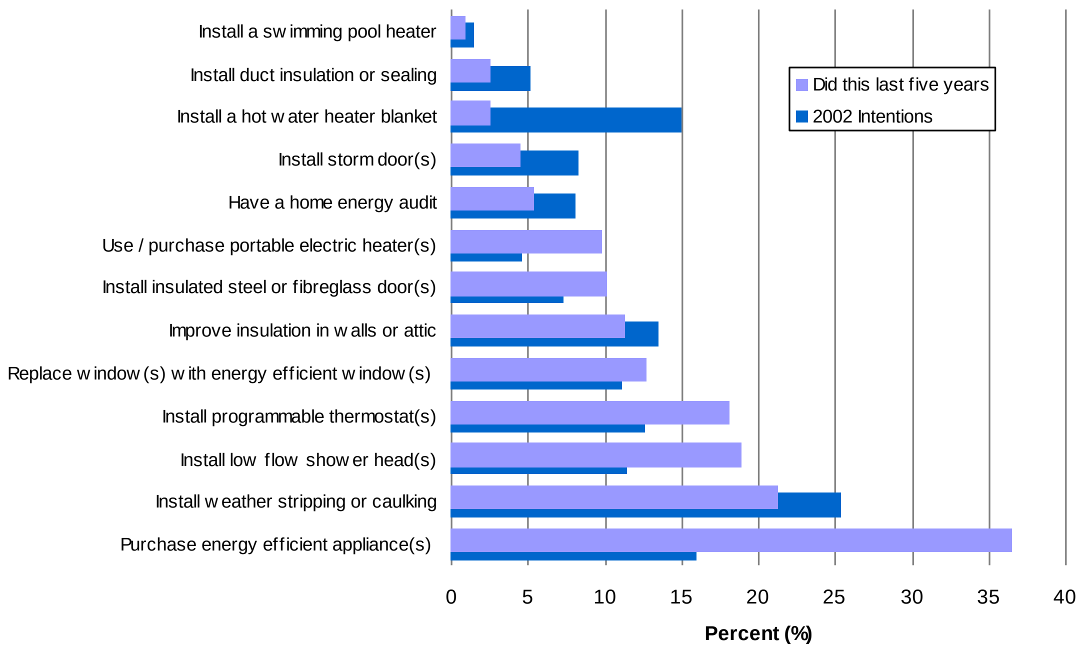
Exhibit 4.46: Renovations in Last Five Years (%)

		Who did the work?			
Type of Renovation	Did this	Did it myself	Used a contractor	Myself & used a contractor	Non-Response
Purchased energy efficient appliance(s)	36.5	--	--	--	--
Installed weather stripping or caulking	21.3	16.3	2.1	0.7	2.2
Installed low flow shower head(s)	18.9	13.9	2.3	0.3	2.4
Installed programmable thermostat(s)	18.2	11.7	5.1	0.1	1.3
Replaced windows (any kind)	15.8	4.4	9.2	0.8	1.4
Replaced window(s) with energy efficient window(s)	12.8	3.3	7.9	0.9	0.7
Improved insulation in walls or attic	11.3	6.0	3.7	0.8	0.8
Installed insulated steel or fibreglass door(s)	10.2	4.9	4.4	0.3	0.6
Started using, or increased usage of, portable electric heater(s)	9.8	--	--	--	--
Had a home energy audit	5.4	--	4.5	--	0.9
Installed storm door(s)	4.5	2.3	1.6	0.2	0.4
Installed a hot water heater blanket	2.6	1.8	0.4	0.1	0.3
Installed duct insulation or sealing	2.6	1.5	0.9	0.1	0.1
Installed a hot tub heater	2.1	0.6	1.4	--	0.1
Installed a swimming pool heater	1.0	--	0.9	--	0.1
None of the above	29.1	--	--	--	--

Unweighted base = 2038

Figure 4.2 compares the renovations undertaken during the past five or so years from the 2008 REUS and compares them to renovations planned by respondents to the 2002 REUS. The two surveys represent different residential customer samples, and different time horizons (last five years for those undertaken by 2008 REUS participants, and two years for those planned by 2002 REUS participants). However, with some notable exceptions, the frequencies of various renovation actions – planned and undertaken – tend to predict what people will do.

Figure 4.2: Renovations Undertaken (2008) Versus Planned (2002)



The age of the home influences how many have undertaken renovations in the past five years, and also the type of renovation. These data are summarized in Exhibit 4.47.

Exhibit 4.47: Renovations in Last Five Years by Age of Residence (%)

Insulation Rating	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	2008 TG
Purchased energy efficient appliance(s)	34.5	40.9	37.6	37.8	32.2	12.0	36.5
Started using, or increased usage of, portable electric heater(s)	10.8	12.2	8.4	11.5	3.5	11.3	9.8
Improved insulation in walls or attic	17.5	19.4	10.9	7.0	1.5	7.0	11.3
Installed weather stripping or caulking	24.0	27.4	27.9	15.4	10.9	3.7	21.3
Replaced windows (any kind)	25.6	23.4	23.6	6.3	2.3	--	15.8
Replaced window(s) with energy efficient window(s)	21.0	19.9	16.7	5.6	2.4	--	12.8
Installed storm door(s)	4.3	7.1	3.9	4.1	2.7	0.3	4.5
Installed insulated steel or fibreglass door(s)	15.0	16.6	15.0	1.8	2.9	7.4	10.2
Installed low flow shower head(s)	15.8	23.3	18.1	23.4	13.0	0.6	18.9
Installed programmable thermostat(s)	14.7	21.3	22.1	20.1	11.9	11.0	18.2
Had a home energy audit	2.2	6.9	10.6	5.4	1.1	--	5.4
Installed duct insulation or sealing	5.1	1.8	4.0	0.8	2.0	--	2.6
Installed a hot water heater blanket	1.5	3.2	1.1	3.0	4.2	--	2.6
Installed a swimming pool heater	--	2.6	0.6	--	0.8	--	1.0
Installed a hot tub heater	1.3	3.2	2.0	1.5	1.3	0.1	2.1
None of the above	24.4	18.4	26.0	28.1	48.0	68.8	29.1

Unweighted base = 2036

Renovations planned in the next two years, ranked by the frequency of response, are summarized in Exhibit 4.48.

Exhibit 4.48: Renovations Planned in Next Two Years (%)

		Who will do the work?			
Type of Renovation	**Plan to do this**	**Do it myself**	**Use a contractor**	**Myself & use a contractor**	**Non-Response**
Purchase energy efficient appliance(s)	16.7	--	--	--	--
Replace window(s) with energy efficient window(s)	12.3	3.8	5.2	1.6	1.7
Install weather stripping or caulking	12.0	8.7	0.4	0.4	2.5
Replace windows (any kind)	8.7	2.4	4.8	0.4	1.1
Improve insulation in walls or attic	6.9	2.8	2.0	0.8	1.3
Install high efficiency gas furnace	6.6	0.6	4.6	0.5	0.9
Install low flow shower head(s)	6.4	4.5	0.3	0.1	1.5
Install programmable thermostat(s)	6.2	3.1	1.3	0.5	1.3
Install a hot water heater blanket	5.5	3.9	0.1	0.1	1.4
Have a home energy audit	5.0	0.4	3.2	0.3	1.1
Install insulated steel or fibreglass door(s)	4.5	2.1	1.4	0.3	0.7
Purchase portable electric heater(s)	3.4	--	--	--	--
Install storm door(s)	3.2	1.8	0.5	0.1	0.8
Install mid-efficiency gas furnace	3.2	0.1	2.5	0.4	0.2
Install duct insulation or sealing	2.2	1.5	0.0*	0.1	0.6
Install swimming pool heater	0.3	0.0*	0.1	0.1	0.1
Install hot tub heater	0.2	0.1	0.1	0.1	--
None of the above	50.4	--	--	--	--

* value less than 0.1%

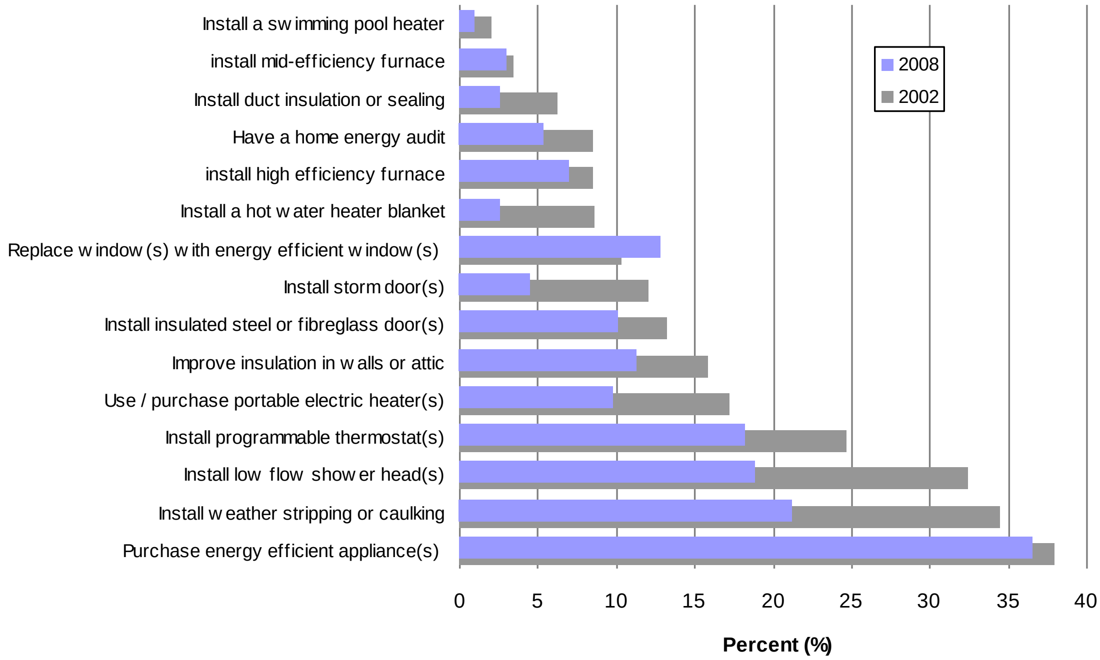
Purchasing energy efficient appliances ranked number one in terms of planned actions mentioned by 17% of all survey respondents, followed by installing energy efficient windows (12%), and installing weather stripping or caulking (12%). While the numbers of respondents that plan to install a mid- or high efficiency furnace are relatively modest (n=145 or 10%), respondents are approximately twice as likely to install a high efficiency unit (6.6%) than a mid-efficiency unit (3.2%).

Figure 4.3 compares renovation plans for the next two years based on the 2008 REUS with renovation plans of customers who participated in the 2002 REUS. The findings are ranked by the percentage of respondents indicating they intended to undertake the activity in the upcoming two years.

In general terms, the relative popularity of many of the planned renovations remains unchanged from 2002. Exceptions including the installation of hot water heater blankets, installation of doors (storm and insulated steel or fibreglass), and the use / purchase of portable electric heaters.

The percentage of 2008 REUS respondents indicating they are planning a particular renovation is less than that indicated in the 2002 survey for most renovations. Exceptions are replacing windows with energy efficient windows (more than 2002), and purchasing energy efficient appliances (effectively equal to 2002). The modest pullback in renovation plans may be a function of the amount of work done to date, or possibly the economic uncertainty associated with the global financial crisis that was occurring during the 2008 survey. The natural reaction during uncertain economic times is to restrain discretionary spending, and this may be reflected in respondents' stated intentions.

Figure 4.3: Renovations Planned in Next Two Years – 2008 REUS Versus 2002 REUS



4.8.1 Renovations Involving Fireplaces and Heating Stoves

Eleven percent (11%) of respondents indicated they had undertaken renovations or changes to their fireplaces or heating stoves during the last five years (Exhibit 4.49).

Exhibit 4.49: Renovations / Changes to Fireplaces or Heating Stoves Last Five Years (%)

	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	562	706	553	205	133	2159
Yes	11.2	9.9	12.1	12.8	5.9	11.2
No	88.8	90.1	87.9	87.2	94.1	88.8
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Of the possible changes listed in Exhibit 4.50, respondents making changes during the last five years were most likely to have installed a gas heater type fireplace insert in an existing wood fireplace (4% of all respondents). The numbers for the other changes are small and caution is advised in their interpretation.

Exhibit 4.50: Renovations / Changes to Fireplaces and Heating Stoves in Last Five Years (%)

		Who did the work			
Type of Renovation	Did this	Did it myself	Used a contractor	Myself & used a contractor	Non-Response
Installed free standing gas fireplace or heating stove	1.5	0.1	1.3	0.1	--
Installed decorative gas fireplace	1.4	0.2	1.2	--	--
Installed electric fireplace	1.0	0.9	0.1	--	--
Installed wood stove	0.6	0.3	0.3	0.1	--
Installed gas heater type fireplace insert in existing wood fireplace	3.8	0.4	3.2	0.3	--
Installed energy efficient wood burning fireplace insert in existing wood fireplace	0.6	0.0*	0.5	--	--
Removed or disconnected gas fireplace	1.0	0.4	0.5	0.1	--
Removed wood fireplace or wood stove	1.1	0.7	0.3	--	0.1
Installed glass fireplace doors	0.4	0.1	0.3	--	--
Replaced decorative gas fireplace with heater type insert	1.4	0.2	0.9	0.1	0.2

* value less than 0.1%

Approximately 8% of Terasen customers plan to undertake renovations involving fireplaces or heating stoves in the next two years (Exhibit 4.51). There are no statistically significant differences between regions.

Exhibit 4.51: Renovations to Fireplaces or Heating Stoves in Next Two Years (%)

	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	565	712	551	204	133	2165
Yes	8.9	6.6	7.6	9.2	8.1	8.2
No	91.1	93.4	92.4	90.8	91.9	91.8
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Renovations involving fireplaces or heating stoves, by type of renovation, are summarized in Exhibit 4.52. Installing a gas heater type fireplace insert in an existing wood fireplace was the most frequently mentioned renovation (2.8%), followed by installing a free standing gas fireplace or heater stove (1.4%), and installing an electric fireplace (1.1).

Exhibit 4.52: Renovations to Fireplaces and Heating Stoves Planned in Next Two Years (%)

		Who will do the work			
Type of Renovation	Plan to do this	Do it myself	Use a contractor	Myself & use a contractor	Non-Response
Install gas heater type fireplace insert in existing wood fireplace	2.8	0.4	2.1	0.1	0.2
Install free standing gas fireplace or heating stove	1.4	0.0*	0.8	0.6	--
Install electric fireplace	1.1	0.9	0.2	--	--
Install energy efficient wood burning fireplace insert in existing wood fireplace	1.0	0.1	0.6	0.3	--
Install decorative gas fireplace	0.9	0.1	0.4	0.4	--
Remove wood fireplace or wood stove	0.8	0.3	0.3	--	--
Install wood stove	0.6	0.2	0.2	0.2	--
Install glass fireplace doors	0.4	0.3	0.0*	--	--
Replace decorative type gas fireplace with heater type insert	0.4	--	0.4	0.1	--
Remove or disconnect gas fireplace	0.3	0.0*	0.2	--	--

Totals may not sum due to rounding.
* value less than 0.1%

The two most commonly provided reasons for undertaking or planning to undertake renovations, as indicated in Exhibit 4.53, were to reduce energy costs (38% of respondents) and to increase the comfort of the home (35%). Twenty-four percent (24%) of respondents indicated the renovations were / will be part of a general home renovation. These three reasons were also the most frequently mentioned in 2002.

Exhibit 4.53: Reasons for Undertaking or Planning Renovations (%) Multiple Responses Allowed

Reason	2008 TG	2002 TGI
Reduce energy costs	37.7	47.6
Increase comfort of home	35.3	43.0
Part of general home renovation	23.8	27.8
Increase resale value of home	17.6	24.4
Response to increases in the price of energy	16.9	31.1 [1]
Expect energy prices to rise in the future	12.2	n/a
Part of regular home maintenance / repairs	0.9	n/a
Reduce consumption to benefit environment	0.4	n/a
Other	1.8	n/a

Columns do not sum to 100% because of multiple responses
[1] 2002 REUS worded this category as “Response to natural gas price increases”

5 SPACE HEATING

This section summarizes key data gathered on space heating fuels and methods, furnace and boiler efficiencies, pilot light usage, fuel switching and heating equipment replacement behaviours.

5.1 Main Space Heating Fuel

Natural gas is the main (primary) space heating fuel for 91% of TG customers (Exhibit 5.1). Electricity (7%) is the next most common primary fuel used to heat the home. Individually, none of the other fuels are used by more than 1% of TG customers. Five percent (5%) of TGI customers use electricity as their main space heating fuel, compared to 4% in 2002 and 3% in 1993. Differences between the three survey years are not statistically significant at the 95% confidence level. The proportion of TGI homes with natural gas as the main fuel is statistically unchanged from previous years. Regionally, electricity use as a main space heating fuel is significantly more prevalent for TGVI (26%) and TGW (30%) than the other regions. Slightly more than half (52%) of TGW customers identified piped propane as their primary space heating fuel. Of interest, 15% of TGW respondents appear to have confused their propane service with natural gas, a service not available at the time of the survey.

Exhibit 5.1: Main Space Heating Fuel by Region (%)

Main Space Heating Fuel	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI [2]	1993 TGI
Unweighted base	575	727	561	209	137	2209	1439	1610	4814
Electricity	5.5	2.9	26.3	29.5	2.9	6.9	4.7	3.5	3.1
Natural gas	93.9	93.0	70.5	15.2	94.2	91.1	93.6	92.9	93.1
Piped propane	0.3	0.0	0.8	52.4	--	0.4	0.2	0.6	0.1
Bottled propane	--	0.2	--	--	--	0.1	0.1	--	--
Oil	--	--	1.6	--	--	0.2	0.0	0.1	0.1
Wood	--	3.1	0.5	2.0	0.7	0.9	0.9	1.4	1.0
Other	--	0.5	0.3	--	--	0.2	0.2	0.3	0.3
DK[1]	0.3	0.2	0.0	0.9	2.2	0.3	0.3	1.8	2.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	--	--

Totals may not sum due to rounding.
[1] Data for 2002 and 1993 may include non-responses (missing values).
[2] Data for 2002 included multiple responses on the main space heating fuel.

Exhibit 5.2 summarizes the mix of main space heating fuels for the three building types. Natural gas is the primary space heating fuel for all building types, but VSDs are significantly more likely to use electricity as their primary fuel (36%) compared to MFDs (13%) or SFDs (6%).

Exhibit 5.2: Main Space Heating Fuel by Building Type (%)

Main Space Heating Fuel	SFD	VSD	MFD	2008 TG
Unweighted base	1362	241	606	2209
Electricity	6.3	35.6	12.9	6.9
Natural gas	91.6	63.4	85.9	91.1
Piped propane	0.4	--	0.7	0.4
Bottled propane	0.1	--	--	0.1
Oil	0.2	--	--	0.2
Wood	1.0	--	0.1	0.9
Other	0.2	0.9	0.2	0.2
DK	0.3	0.1	0.1	0.3
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

5.2 Supplementary Space Heating Fuel

Fifty-six percent (56%) of TG customers use a supplementary fuel to heat their residences (Exhibit 5.3). Regionally, the use of supplementary heating fuel(s) is lowest in FN (44%) and highest in TGW (81%). The proportion of TGI customers that used one or more supplementary heating fuels in 2008, compared with 2002 is not significantly different at the 95% confidence level.

Exhibit 5.3: Incidence of Supplementary Space Heating Fuel by Region (%)

	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI [1]
Unweighted base	578	730	566	209	138	2221	1439	1610	n/a
Use supplementary fuel(s)	54.3	55.3	64.8	80.8	43.5	55.6	54.6	52.8	n/a

[1] Not queried in the 1993 REUS

The incidence of supplementary heating fuels is higher for MFDs (65%) versus SFDs (54%) and VSDs (55%) (Exhibit 5.4).

Exhibit 5.4: Incidence of Supplementary Space Heating Fuel by Building Type (%)

	SFD	VSD	MFD	2008 TG
Unweighted base	1369	242	610	2221
Use supplementary fuel(s)	54.3	55.3	64.8	55.6

Electricity is the most common supplementary heating fuel, representing 71% of those with a supplementary fuel (Exhibit 5.5). The next most common supplementary fuels are wood (18%) and natural gas (12%).

The use of electricity as a supplementary fuel for TGI customers has increased significantly since 2002, rising from 58% to 73%. Use of natural gas as a supplementary fuel has decreased commensurately from 27% to 9%. Supplementary fuels used for space heating were not queried in the 1993 REUS.

Exhibit 5.5: Supplementary Space Heating Fuel(s) by Region (%)
Multiple Responses Allowed

Supplementary Space Heating Fuels	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	337	367	385	169	61	1319	765	850
Electricity	75.2	68.0	54.4	59.1	68.2	70.8	73.0	57.9
Natural gas	8.9	9.2	34.8	6.8	4.5	11.9	9.0	27.0
Piped propane	--	--	0.1	20.5	--	0.1	0.0	0.5
Bottled propane	0.6	--	--	--	--	0.3	0.4	0.3
Oil	0.6	0.8	0.4	--	--	0.6	0.7	0.3
Wood	14.0	28.8	14.8	31.8	22.7	18.2	18.5	23.5
Other	0.6	1.2	0.8	--	--	0.8	0.8	1.4 [1]
DK	7.2	5.7	1.7	4.5	4.5	6.1	6.7	4.5

Columns do not sum to 100% because of multiple responses.
[1] Includes kerosene, which was reported separately in 1993.

Recognizing that some homes will use more than one supplementary fuel for space heating, 2008 REUS respondents were asked to indicate which supplementary fuel is the one used the most. The results are summarized in Exhibit 5.6. Electricity was mentioned by 67% of TG customers, followed by wood (14%), and natural gas (11%). Regionally, differences of note include the significantly higher use of natural gas in the TGVI region (34%) compared to other regions, and the significantly higher incidence of wood in the INT, TGW and FN regions compared to LM and TGVI. Piped propane as a supplementary fuel is particular to TGW (19% of homes using supplementary space heating fuels).

Exhibit 5.6: Most Used Supplementary Space Heating Fuel by Region (%)

Most Used Supplementary Space Heating Fuel	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	333	359	382	158	61	1293
Electricity	72.4	61.2	52.9	53.9	65.6	67.1
Natural gas	7.9	8.6	34.1	6.2	3.3	11.1
Piped propane	--	--	0.0*	18.9	--	0.1
Bottled propane	0.6	--	--	--	--	0.4
Oil	0.6	0.4	0.4	0.6	1.6	0.5
Wood	11.3	22.7	10.0	16.5	23.0	14.2
Other	--	1.2	0.8	--	--	0.4
DK	7.3	5.9	1.7	3.8	6.6	6.3
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
* Value less than 0.1%

Of those customers who use natural gas as a supplementary fuel for spacing heating, 82% of them use electricity as the main fuel to heat their home (Exhibit 5.7). Eleven percent (11%) use wood.

Exhibit 5.7: Main Heating Fuel – Households with Natural Gas as Secondary Fuel

Supplementary Fuel	2008 TG
Unweighted base	269
Electricity	81.8
Piped propane	3.0
Bottled propane	0.9
Oil	1.6
Wood	10.6
Other	1.1
DK	0.9

Columns do not sum to 100% because of multiple responses.

Exhibit 5.8 summarizes the supplementary space heating fuels for the three building types. Of note, VSDs are more likely to list natural gas as a supplementary fuel compared to SFDs and MFDs. Also, 19% of respondents in SFDs indicated wood was a supplementary fuel, significantly more than the other two building types.

Exhibit 5.8: Supplementary Space Heating Fuel(s) by Building Type (%) Multiple Responses Allowed

Supplementary Fuel	SFD	VSD	MFD	2008 TG
Unweighted base	808	148	363	1319
Electricity	70.9	47.4	71.4	70.8
Natural gas	11.4	39.0	17.9	11.9
Piped propane	0.0*	--	0.5	0.1
Bottled propane	0.4	--	--	0.4
Oil	0.7	1.0	0.2	0.6
Wood	19.2	0.7	3.7	18.2
Other	0.8	0.2	0.1	0.8
DK	6.0	12.3	8.4	6.1

Columns do not sum to 100% because of multiple responses.
* Value less than 0.1%

Of the supplementary space heating fuels identified previously, Exhibit 5.9 summarizes the most used supplementary space heating fuel for each of the three building types. Consistent with the previous exhibit, VSDs are significantly more likely than SFDs and MFDs to use natural gas as their supplementary fuel (39% versus 11% and 18% respectively), and SFDs are significantly more likely than VSDs and MFDs to use wood as their most used supplementary fuel (15% versus 0.3% and 2%).

Exhibit 5.9: Most Used Supplementary Space Heating Fuel by Building Type (%)

Supplementary Fuel	SFD	VSD	MFD	2008 TG
Unweighted base	788	148	357	1293
Electricity	67.0	47.4	70.5	67.1
Natural gas	10.5	38.8	17.9	11.1
Piped propane	--	--	0.5	0.1
Bottled propane	0.4	--	--	0.4
Oil	0.6	1.0	--	0.5
Wood	15.1	0.3	2.4	14.2
Other	0.5	0.2	--	0.4
DK	6.1	12.3	8.6	6.3
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Exhibit 5.10 summarizes the relative popularity of space heating fuels regardless of whether they are used as a primary or secondary fuel. In total, 96% of TG customers use natural gas for space heating, either in a primary or supplementary capacity. This percentage is unchanged from 2002 (i.e., within the margins of error for the two estimates). TGVI customers are significantly less likely to have natural gas as a space heating fuel (90%) compared to all other regions. Fewer than 4% of customers do not use natural gas for space heating. In these cases, natural gas is used for non-space heating end uses (e.g., hot water heating, cooking, etc.).

Exhibit 5.10: Net Space Heating Fuel by Region (%)

Main or Supplementary Heating Fuel	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	578	730	566	209	138	2221	1446	1610
Electricity	41.6	39.4	42.1	47.3	30.0	41.1	40.9	36.1
Natural gas	97.2	96.5	89.6	96.4	98.0	96.3	97.0	96.0
Piped propane	--	--	0.0*	16.4	--	0.0*	0.0*	0.8
Bottled propane	0.3	--	--	--	--	0.2	0.2	--
Oil	0.3	0.5	0.3	--	--	0.4	0.4	0.0*
Wood	7.6	15.9	9.6	25.5	10.0	10.1	10.1	13.5
Other	0.3	0.7	0.5	--	--	0.4	0.4	0.7
DK	3.9	3.2	1.1	3.6	2.0	3.4	3.7	3.8

Columns do not sum to 100% because of multiple responses.
* Value less than 0.1%.

5.3 Change in Space Heating Fuel

On average, 3% of TG customers changed their main space heating fuel in the last five years. On a regional basis, 11% of TGVI customers changed their fuel, significantly more than all other regions. The proportion of TGI customers that changed fuels in the past five years was somewhat lower in 2008 compared to 2002 and 1993 (1.9% versus 4.1% and 3.4%).

Exhibit 5.11: Change in Main Space Heating Fuel – Last Five Years (%)

Changed Fuel?	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI [1]
Unweighted base	566	715	557	206	135	2179	1416	1610	4814
Yes	1.2	3.4	11.2	1.9	0.7	2.8	1.9	4.1	3.4
No	98.8	96.6	88.8	98.1	99.3	97.2	98.1	93.2	95.7
DK/NR	--	--	--	--	--	--	--	2.7	1.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] The 1993 study queried changes in space heating fuel over two years.

Of those who switched their main or supplementary heating fuel in the last five years, there has been a net shift away from natural gas to electricity. Exhibit 5.12 shows that 57% switched from natural gas as their space heating fuel, compared to 17% who switched from electricity. Another 19% switched from heating oil. Proportionately, three times as many people switched to their current fuel from natural gas than from electricity. Although the sample sizes are very small, the net shift away from natural gas appears most evident in the LM, INT and TGVI regions. The 2008 REUS marks the first time this has occurred, as the 2002 and 1993 surveys showed a positive gain for natural gas over electricity (42% to 29% in 2002 and 24% to 5% in 1993).

Exhibit 5.12: Previous Space Heating Fuel by Region (%)

Primary or Supplementary Heating Fuel	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI [2]	1993 TGI
Unweighted base [1]	9	19	49	4	1	82	29	74	152
Electricity	34.5	7.0	12.4	26.0	--	16.8	19.7	41.6	24.0
Natural gas	65.5	79.0	32.3	--	--	56.5	72.7	28.5	4.6
Piped propane	--	--	--	48.1	--	0.1	--	2.0	2.3
Bottled propane	--	--	2.4	--	--	1.0	--	0.8	3.4
Oil	--	--	48.1	26.0	--	19.2	--	13.9	36.5
Wood	--	14.0	4.8	--	100.0	6.5	7.6	20.2	11.4
DK	--	--	--	--	--	--	--	1.2	17.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	--	100.0

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Multiple responses recorded so total does not sum to 100%.

For those who switched fuels in the last five years, Exhibit 5.13 summarizes the fuel they currently use against the fuel they previously used. Of those who switched to electricity, 98% had previously used natural gas to heat their house, and a small percentage (2%) had used heating oil. Of those who switched to natural gas, 43% had used heating oil, 40% had used electricity, and 15% had used wood prior to the switch.

Exhibit 5.13: Current and Previous Space Heating Fuels – Shares Across (%)

Previous Fuel ▸ / ▼ Current Fuel	Electricity	Natural gas	Piped propane	Bottled Propane	Oil	Wood	Total
Electricity	--	97.9	--	--	2.1	--	100.0
Natural gas	39.5	--	0.2	2.2	42.8	15.2	100.0
Piped propane	24.1	51.8	--	--	24.1	--	100.0
Wood	--	100.0	--	--	--	--	100.0
Other	--	100.0	--	--	--	--	100.0

Totals may not sum due to rounding.
Unweighted base = 82

Exhibit 5.14 presents the same data, but from the perspective of the previous space heating fuel. The data show that of the customers who switched from natural gas to another fuel, 78% switched to electricity, 16% to wood, 0.2% to piped propane, and 6% to other fuels. Of those who switched from oil, 95% switched to natural gas. All households who previously used bottled or piped propane, switched to natural gas.

Exhibit 5.14: Current and Previous Space Heating Fuels – Shares Down (%)

Previous Fuel ▸ / ▼ Current Fuel	Electricity	Natural gas	Piped propane	Bottled Propane	Oil	Wood
Electricity	--	77.7	--	--	5.0	--
Natural gas	99.7	--	100.0	100.0	94.8	100.0
Piped propane	0.3	0.2	--	--	0.2	--
Wood	--	15.9	--	--	--	--
Other	--	6.2	--	--	--	--
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
Unweighted base = 82

5.4 Main Space Heating Method

Respondents were queried about the methods used to heat their home. Methods differ from fuels in that they refer to an appliance or technology (e.g., portable electric heaters, air source heat pumps, etc.) regardless of the fuel used. Respondents were asked to indicate their main method to heat their residence, the second most used method, and then all other methods. The primary objective of this section of REUS was to understand the relative roles of primary and supplementary heating methods.

Main space heating methods are summarized in Exhibit 5.15. Comparisons with the 1993 and 2002 data are provided. The data from 2002 were rebased to 100% as the latter included multiple responses by some respondents. As a result, caution is advised in comparing the 2002 results with the 2008 data.

Central forced air furnaces are the main heating method for 73% of all TG customers, and 76% of TGI customers. Use of forced air furnaces as the main heating method was highest in FN (93%) and lowest in TGW (39%). The use of forced air furnaces by TGI customers is significantly below that of 1993 when 85% reported this method as their main heating method.

After forced air furnaces, the next most common main heating method for TG customers is hot water radiant floor heat (8%). Of note, 10% of LM customers and 14% of TGW customers reported using hot water radiant floor heat as their main heating method, significantly higher than other regions. Overall, the use of radiant floor heat (electric and hot water) among TGI customers has become increasingly popular since 1993, when it accounted for only 3%.[23]

The use of air source heat pumps is highest among TGVI customers (9%), and represents 3% of all TG customers. TGVI and TGW customers stand out from customers in other regions in their use of a gas fireplace as their main heating method (11% versus 3%).

[23] Electric radiant heat includes radiant ceilings, walls, and floors.

Exhibit 5.15: Main Heating Method by Region (%)

Main Heating Method	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	568	716	552	207	132	2175	1043	1610	4814
Central forced air furnace	72.2	84.6	50.7	38.8	92.5	73.4	76.0	76.2	85.1
Wired-in electric heater	2.0	1.0	10.4	16.4	1.5	2.6	1.7	1.6 [1]	1.8
Wired-in electric wall heater	0.5	0.2	3.5	5.8	--	0.7	0.4	n/a	n/a
Hot water baseboards	6.8	0.9	4.8	3.4	0.7	5.0	5.0	4.8	5.9
Hot water radiant floor heat	10.3	1.1	3.1	13.7	2.2	7.1	7.5	6.1	2.6
Electric radiant heat	1.4	--	2.1	4.4	--	1.1	1.0	0.3	0.3
Gas wall heater	0.7	0.2	0.3	1.4	--	0.5	0.6	2.1	n/a
Portable electric heaters	--	0.7	--	--	--	0.2	0.2	0.8	n/a
Wood stove	--	2.5	0.5	1.5	--	0.7	0.7	1.5	0.9
Gas heater stove	--	1.1	3.2	1.0	0.7	0.6	0.3	n/a	n/a
Heat pump - air source	2.0	3.4	8.6	1.0	--	3.0	2.4	0.6 [2]	0.2 [2]
Heat pump - ground source	0.3	--	0.3	--	--	0.2	0.2		
Wood burning fireplace	--	0.7	0.3	0.5	0.7	0.2	0.2	5.6 [3]	0.7 [3]
Electric fireplace	--	0.2	0.5	--	--	0.1	0.1		
Gas fireplace	3.3	2.7	10.9	11.3	--	3.9	3.1		
Other	0.6	0.5	0.8	0.9	1.5	0.6	0.6	0.4	2.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Adjusted for multiple reporting (Habart 2003)
[2] Not differentiated in 2002 or 1993 studies. Includes both air source and ground source heat pumps.
[3] Not differentiated in 2002 or 1993 studies. Includes wood, electric, and gas fireplaces.

The 2008 data for main heating method by building type is summarized in Exhibit 5.16. VSDs stand out as using a significantly different mix of heating methods compared to SFDs and MFDs. Natural gas fireplaces are the most common method of heating VSDs (28%), followed by forced air furnaces (21%) and wired-in electric heaters (20%). The main heating methods for MFDs more closely resemble SFDs, with forced furnaces as their main method (69% versus 74% in SFD's). However, compared to SFDs, MFDs have a greater percentage of households using gas fireplaces (9% versus 3%) and either electric or hot water radiant heat (11% versus 8%) .

The penetration of forced air furnaces in VSDs is highest in the LM and INT regions (data not shown). These furnaces include self-contained through-the-wall heating and cooling units which require no ducting.[24]

[24] Two examples of self-contained through-the-wall furnace/AC units include Magic-Pak® manufactured by Lennox International and Skypak® manufactured by Johnson Controls. Both units include an 80% AFUE power vented furnace, combined with an air conditioning unit. The self-contained units are built into the outside wall cavity and require no internal ducting.

Exhibit 5.16: Main Heating Method by Building Type (%)

Main Heating Method	SFD	VSD	MFD	2008 TG
Unweighted base	1340	234	601	2175
Central forced air furnace	73.9	21.2	69.3	73.4
Wired-in electric heater	2.3	20.2	5.2	2.6
Wired-in electric wall heater	0.6	8.1	1.4	0.7
Hot water baseboards	5.2	0.9	1.5	5.0
Hot water radiant floor heat	6.9	9.5	10.3	7.1
Electric radiant heat	1.1	4.0	1.1	1.1
Gas wall heater	0.5	1.0	0.6	0.5
Portable electric heaters	0.2	--	0.5	0.2
Wood stove	0.8	--	0.1	0.7
Gas heater stove	0.7	1.5	--	0.6
Heat pump - air source	3.1	2.6	0.9	3.0
Heat pump - ground source	0.2	0.9	0.1	0.2
Wood burning fireplace	0.2	--	0.1	0.2
Electric fireplace	0.1	--	--	0.1
Gas fireplace	3.4	28.2	8.7	3.9
Other	0.6	2.0	0.2	0.6
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

5.5 Secondary Heating Methods

Seventy-three percent of households use more than one method to heat their home. These “secondary” methods have been queried in the previous two REUS surveys without qualification as to which are used relatively more than the others. To address this issue, the 2008 REUS asked respondents to identify their most used secondary heating method, and then all remaining methods.

Exhibit 5.17 summarizes the second most used method to heat the residence. Gas fireplaces are used by 29% of all TG customers, making it the most commonly used secondary method for space heating. Regionally, the use of gas fireplaces was highest among TGVI customers (35%) and lowest among FN customers (12%). Wired-in and portable electric heaters are the next most commonly reported secondary heating methods, used by 11% and 10% of TG customers respectively. Of note, 19% of FN customers reported using portable electric heaters, significantly higher than any other region. Twenty-seven percent (27%) of TG customers reported only one method of heating (i.e., no secondary method). Regionally, the proportion ranged from a low of 18% for TGVI customers to a high of 42% for FN customers.

Exhibit 5.17: Second Most Used Heating Method by Region (%)

Second Most Used Heating Method	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	568	716	552	207	132	2175
Central forced air furnace	1.9	5.2	4.7	1.5	1.5	3.1
Wired-in electric heater	12.6	5.1	14.6	18.4	1.5	10.7
Wired-in electric wall heater	4.9	2.2	5.5	7.2	2.2	4.2
Hot water baseboards	1.4	--	--	1.0	1.5	0.9
Hot water radiant floor heat	0.3	0.2	0.6	2.4	1.5	0.3
Electric radiant heat	1.2	2.5	1.4	11.7	0.8	1.6
Gas wall heater	0.0	0.2	0.8	--	--	0.2
Portable electric heaters	9.9	11.3	6.8	1.4	19.4	10.0
Wood stove	0.7	5.4	1.8	1.5	6.7	2.1
Gas heater stove	0.4	2.5	2.1	0.5	2.2	1.1
Heat pump - air source	0.3	2.3	0.0*	0.5	0.8	0.8
Heat pump - ground source	--	0.2	0.0*	--	--	0.1
Wood burning fireplace	6.1	6.1	4.5	12.7	3.7	5.9
Electric fireplace	1.7	3.1	2.6	0.9	4.5	2.2
Gas fireplace	30.4	23.4	35.3	23.1	11.9	28.9
Other	0.6	1.4	0.8	1.5	--	0.9
No Secondary Heating	**27.5**	**29.0**	**18.3**	**15.7**	**41.8**	**27.0**
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
* Value less than 0.1%.
[1] All customers answering QB12 (primary space heating method).

Data on the most common secondary heating method, summarized by the three building types, are summarized in Exhibit 5.18. Gas fireplaces, wired-in electric heat, and portable electric heaters are the top three most commonly mentioned secondary heat sources.

Exhibit 5.18: Most Used Secondary Heating Method by Building Type (%)

Second Most Used Heating Method	SFD	VSD	MFD	2008 TG
Unweighted base [1]	1340	234	601	2175
Central forced air furnace	3.3	1.7	1.0	3.1
Wired-in electric heater	10.6	19.8	12.4	10.7
Wired-in electric wall heater	4.1	5.9	5.6	4.2
Hot water baseboards	0.9	--	1.4	0.9
Hot water radiant floor heat	0.3	0.7	0.2	0.3
Electric radiant heat	1.5	5.7	2.2	1.6
Gas wall heater	0.1	1.0	0.2	0.2
Portable electric heaters	9.8	4.7	12.4	10.0
Wood stove	2.2	--	0.5	2.1
Gas heater stove	1.2	1.5	0.5	1.1
Heat pump - air source	0.9	0.3	0.1	0.8
Heat pump - ground source	0.1	--	0.0*	0.1
Wood burning fireplace	6.3	--	1.2	5.9
Electric fireplace	2.0	1.0	5.1	2.2
Gas fireplace	29.1	38.6	26.2	28.9
Other	0.9	0.7	0.2	0.9
No secondary heating	**26.8**	**18.3**	**31.1**	**27.0**
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
* Value less than 0.1%.
[1] All customers answering QB12 (primary space heating method).

All secondary space heating methods are summarized in Exhibit 5.19 with data from 1993 and 2002 provided for comparison. Caution is advised in the interpretation of the 2002 data, as the previous study found that households over-reported their forced air furnaces as either primary or secondary heat sources (Habart 2003).

Exhibit 5.19: All Secondary Heating Methods by Region (%)

Second Most Used Heating Method	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base [1]	568	716	552	207	132	2175	1043	1610	4814
Central forced air furnace	2.0	5.4	5.5	1.5	1.5	3.2	3.0	19.7	2.5
Wired-in electric heater	14.2	7.6	17.6	24.6	2.3	12.8	12.2	16.6	14.2
Wired-in electric wall heater	6.3	2.7	7.9	12.1	3.0	5.5	5.2	n/a	n/a
Hot water baseboards	1.4	0.4	0.3	1.0	1.5	1.0	1.1	2.5	1.0
Hot water radiant floor heat	0.3	0.5	0.6	3.9	2.3	0.4	0.4	2.9	0.9
Electric radiant heat	2.5	3.9	2.5	18.6	0.8	2.9	2.9	1.1	0.2
Gas wall heater	0.4	0.9	0.8	0.5	--	0.6	0.5	3.6	3.4
Portable electric heaters	17.0	18.0	12.6	4.8	20.9	16.8	17.3	16.8	15.8
Wood stove	1.0	6.5	2.9	4.9	8.9	2.7	2.7	5.0	7.5
Gas heater stove	0.4	3.1	2.4	0.5	2.2	1.3	1.2	n/a	n/a
Heat pump - air source	0.3	2.5	0.0*	1.0	0.8	0.9	1.0	0.6 [2]	0.2 [2]
Heat pump - ground source	--	0.2	0.0*	--	--	0.1	0.1		
Wood burning fireplace	9.0	12.1	10.4	23.5	4.5	10.0	9.9	37.1 [3]	39.2 [3]
Electric fireplace	2.7	5.2	4.1	1.9	6.7	3.5	3.4		
Gas fireplace	40.9	32.8	46.9	40.2	16.4	39.2	38.4		
Other	1.6	2.1	2.5	1.5	0.8	1.8	1.7	2.3	5.4
No Secondary Heating	**27.5**	**29.0**	**18.3**	**15.7**	**41.8**	**27.0**	**28.0**	**23.7**	**n/a**

Columns do not sum to 100% because of multiple responses.
[*] Value less than 0.1%.
[1] All customers answering QB12 (primary space heat).
[2] Not differentiated in 2002 or 1993 studies. Includes both air source and ground source heat pumps.
[3] Not differentiated in 2002 or 1993 studies. Includes wood, electric, and gas fireplaces.

Gas fireplaces stand out as the most common secondary heating method, mentioned by 39% of TG customers overall. Regionally, usage is highest among TGVI customers (47%), and lowest among FN customers (16%). The data on forced air furnaces as a supplementary heating method from the 2008 REUS more closely resembles that of 1993.

5.5.1 Main and Secondary Heating Combinations

Exhibit 5.20 summarizes the most common combinations of main and secondary (most used) heating methods by the five TG regions, ranked by most frequent pairings using the TG averages. The most common pairing is a central forced air furnace as the main space heating method and a gas fireplace as the second most used method, representing for 23% of all TG customers. Forced air furnaces with no secondary heating is the next most common at 19%.

Exhibit 5.20: Most Common Main and Secondary Heating Combinations by Region (%)

Main Heating Method & Second Most Used Method	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	568	716	552	207	132	2175
Central forced air furnace & gas fireplace	23.4	22.2	18.7	4.4	11.2	22.5
Central forced air furnace only	18.0	24.2	10.7	4.8	39.6	19.0
Central forced air furnace & electric baseboard heat	10.6	4.3	6.3	7.8	1.5	8.5
Central forced air furnace & portable electric heater	7.6	10.1	4.6	1.0	19.4	8.0
Central forced air furnace & wood burning fireplace	4.8	5.6	3.7	8.2	3.7	4.9
Central forced air furnace & electric wall heater	4.4	1.9	1.8	3.9	--	3.5
Hot water radiant floor heat only	4.1	0.2	0.3	2.4	0.7	2.7
Hot water radiant floor heat & gas fireplace	3.6	0.2	0.9	3.4	--	2.4
Hot water baseboard heat only	2.9	--	1.4	0.5	--	2.0
Central forced air furnace & wood stove	0.4	5.4	1.1	--	6.0	1.8
Electric baseboard heat & gas fireplace	1.0	0.5	7.6	9.1	0.7	1.5
Gas fireplace & electric baseboard heat	0.9	0.2	4.4	6.2	--	1.2
All other combinations	18.3	25.2	38.5	48.3	17.2	22.0
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

While the data does not address what proportion of the heating load is borne by the space heating end uses in each pairing, the data clearly shows differences in the relative popularity of space heating end use pairings between the regions. Of note, INT customers differ from LM customers by their tendency to use furnaces on their own, or to combine with a portable electric heater or a wood stove. TGVI and TGW customers are similar in that they tend to use electric baseboard heat paired with a gas fireplace more than other regions. FN customers tend to either use forced air furnaces soley, or in combination with portable electric heaters.

5.6 Gas Furnaces and Boilers

On average, 12% of TG customers have a gas (natural gas or piped propane) boiler, and 80% have a gas furnace. Eight percent (8%) of respondents did not have either a gas boiler or furnace (Exhibit 5.21). The presence of gas furnaces is highest in the INT region (93%), and lowest in TGW (43%). Gas boilers are most common among TGW and LM customers (20% and 16% respectively).

Twenty-two percent (22%) of respondents reported installing a gas furnace or boiler during the past five years, up from 19% in 2002. Replacement incidence was highest in the LM and FN regions (23% and 24% respectively) and lowest in TGVI (16%).

Exhibit 5.21: Gas Furnaces and Boilers by Region (%)
Natural Gas or Piped Propane

	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	569	716	553	207	137	2182	1422	1610
Gas boiler	16.3	2.6	9.2	20.0	7.3	11.9	12.2	27.7 [1]
Gas furnace	77.6	92.8	57.8	42.7	90.6	79.7	82.2	85.7
No boiler or furnace	6.1	4.6	33.0	37.4	2.2	8.4	5.6	--
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Installed a furnace or boiler in past five years	**23.1**	**20.1**	**16.3**	**21.9**	**23.7**	**21.7**	**22.2**	**18.8**

Totals may not sum due to rounding.
[1] Overstated as some respondents confused boilers with hot water tanks (Habart 2003).

Respondents with boilers were asked to indicate their boiler's efficiency based on the following descriptions of standard and high efficiency boilers:

- standard efficiency (80% to 85% efficiency)
- high efficiency (90% efficiency or higher)

Exhibit 5.22 summarizes the data on boiler efficiency by region. Of note, a large percentage of respondents with boilers did not know its efficiency (43%). Comparisons to 2002 are not provided because it is not possible to identify the proportion of respondents who did not know their boiler's efficiency in 2002.

Exhibit 5.22: Boiler Efficiency by Region Including DKs (%)
Natural Gas or Piped Propane

Boiler Efficiency	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	102	41	44	41	8	236
Standard efficiency (80% to 85%)	39.3	27.8	38.6	41.6	29.7	38.6
High efficiency (90% or higher)	17.5	26.3	23.1	21.9	9.9	18.5
DK	43.2	45.9	38.3	36.5	60.4	42.9
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Data for 2002 not available.

To allow comparisons of boiler efficiency between regions using a common base, and to facilitate comparison with 2002 data, Exhibit 5.23 removes respondents who were unsure of their boiler's efficiency and rebases the results. Sixty-eight percent (68%) of TG customers with a gas boiler indicated it was a standard efficiency unit, and 32% said it was a high efficiency unit. The relative split between high and standard efficiency for TGI customers in 2008 is not statistically different than that of 2002.

Exhibit 5.23: Boiler Efficiency by Region Excluding DKs (%)
Natural Gas or Piped Propane

Boiler Efficiency	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base [1]	51	23	27	26	4	131	78	158
Standard efficiency (80% to 85%)	69.2	51.4	62.5	65.4	74.8	67.6	68.1	69.6
High efficiency (90% or higher)	30.8	48.6	37.5	34.5	25.2	32.4	31.9	30.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Data for 2002 not available

Exhibit 5.24 summarizes the median and mean age of gas boilers. Comparable data for 2002 were unavailable. The average age of gas boilers ranged from 7.2 years in TGVI to 11.7 years in INT.

Exhibit 5.24: Age of Gas Boiler
Natural Gas or Piped Propane

Age of Gas Boiler (years)	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	92	37	34	40	6	209
Median	5.0	5.0	6.0	8.5	7.5	6.0
Mean	9.8	11.7	7.2	9.4	8.7	9.7
Standard deviation	13.7	8.6	3.2	0.9	0.9	9.9

Data for 2002 not available
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Respondents with gas furnaces were asked to indicate the efficiency of their furnace based on the following descriptions:

- **Standard efficiency** - at least 13 years old; uses a pilot light; metal flue that vents through the roof; efficiency less than 78%.
- **Mid-efficiency** - no pilot light; uses an igniter instead; metal flue that vents through the roof; 78% to 85% efficiency.
- **High efficiency** - no pilot light; plastic flue; flue vents either through the roof or the side of the house; 90% efficiency or higher; Energy Star® qualified.

Exhibit 5.25 summarizes the breakdown of furnace efficiency by region, including the percentage of respondents that were unsure of their furnace's efficiency. The proportion of respondents unsure of their furnace's efficiency varied depending upon the region and survey year, making comparisons difficult. As a result, the data were restated to exclude the DK responses to establish a common base. These results are summarized in Exhibit 5.26.

Exhibit 5.25: Furnace Efficiency by Region including DK Responses (%)
Natural Gas or Piped Propane

Gas Furnace Efficiency	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI [1]
Unweighted base	360	587	277	87	123	1434	1070	1279
Standard efficiency (less than 78% AFUE)	49.3	39.7	22.7	30.8	35.0	44.3	46.0	40.1
Mid-efficiency (78% to 85% AFUE)	24.0	35.1	41.4	21.8	37.4	28.8	27.8	21.3
High efficiency (90% AFUE or higher)	11.9	16.1	20.8	30.2	19.5	13.9	13.3	12.2
DK	14.9	9.1	15.1	17.2	8.1	13.1	12.9	26.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Recalculated from 2002 tables to exclude boilers. DK proportioned according to the relative numbers of furnaces.

A preliminary review of the furnace efficiency data raised two issues. The first involved the varying proportion of respondents unsure of their furnace's efficiency by region and by survey year. These proportions were sizable, making regional comparisons of the 2008 data, and comparisons with 2002 data, difficult. The second issue was the movement, or lack thereof, of shares from standard to mid- or high efficiency furnaces since the 2002 REUS, a period which saw Terasen provide approximately 8,600 customers with incentives for the installation of a high efficiency furnace.

To address the issue of varying proportions of respondents unsure of their furnace efficiency level, the data were restated to exclude the DK responses. The second issue was explored by comparing the data on furnace efficiency with furnace age. This investigation found approximately 10% of respondents had indicated they have a standard efficiency furnace but that furnace was younger than 13 years of age. Legislation banning the sale of standard efficiency furnaces took effect in February 1995, meaning these furnaces would have to be, at the minimum, mid-efficiency furnaces. Erring on the conservative side, any standard efficiency furnaces younger than 13 years were recoded as mid-efficiency units and the relative shares recalculated.

Revised furnace efficiency shares, following the two adjustments to the data, are summarized in Exhibit 5.26. Standard efficiency furnaces account for the largest proportion (45%) of gas furnaces still in use by TG customers, followed by mid-efficiency furnaces (39%), and high efficiency furnaces (16%). The proportion of high efficiency furnaces for 2008 is still considered too low. The most likely explanation is that some respondents to the 2008 REUS mistakenly identified their high efficiency furnace as a mid- efficiency furnace, and/or respondents to the 2002 REUS mistook a mid-efficiency furnace as a high efficiency furnace.[25] As there are no further data or information from the REUS surveys that would allow an investigation into the extent of this potential categorization error, the data is left as is with the adjustments and cautions noted.

Exhibit 5.26: Furnace Efficiency by Region – Revised Data (%)
Natural Gas or Piped Propane

Furnace Efficiency	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base [1]	297	513	231	72	113	1226	923	942
Standard efficiency (less than 78% AFUE)	52.1	38.0	19.0	20.7	29.2	45.0	47.0	54.5
Mid-efficiency (78% to 85% AFUE)	34.0	44.2	56.5	42.8	49.5	39.0	37.7	28.9
High efficiency (90% AFUE or higher)	13.9	17.7	24.5	36.5	21.2	16.0	15.3	16.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Exhibit 5.27 summarizes furnace efficiency by dwelling age. Consistent with the introduction of minimum efficiency standards for new furnaces in 1995, homes built since 1995 should have either a mid- or high efficiency furnace. Indeed, all except 3% of TG customers living in homes built between 1996 and 2005 reported having either a mid- or high efficiency furnace. In comparison, only 28% and 17% of respondents in homes built during the 1986 to 1995 period have a mid- or high efficiency furnace.

Exhibit 5.27: Furnace Efficiency by Dwelling Construction Date (%)

Furnace Efficiency	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Year Un-known	2008 TG
Unweighted base [1]	102	291	195	273	282	33	12	1188
Standard efficiency (less than 78% AFUE)	58.5	45.4	57.4	54.7	3.0	--	96.2	45.1
Mid-efficiency (78% to 85% AFUE)	27.0	43.2	28.8	27.9	68.5	38.4	3.8	38.8
High efficiency (90% AFUE or higher)	14.6	11.4	13.8	17.4	28.4	61.6	--	16.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Average furnace age varied from 10.1 years to 15.4 years depending upon the region (Exhibit 5.28). The average age of furnaces owned by TG customers is 14 years.

Exhibit 5.28: Age of Furnace by Region
Natural Gas or Piped Propane

Age of Gas Furnace (years)	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	350	590	274	87	121	1422	1061	1500
Median	12.0	10.0	10.0	10.0	7.0	10.0	10.0	n/a
Mean	15.4	12.5	10.5	10.2	10.1	14.0	14.3	13.4
Standard deviation	21.0	8.7	3.8	0.9	1.6	12.0	13.8	n/a

Totals may not sum due to rounding.

[25] Natural Resources Canada end use models place the national shares of mid-efficiency and high efficiency furnaces in 2006 at 34% and 20% respectively, which suggests that high efficiency shares in British Columbia in 2008 should be at this level or higher. Source: Energy Use Data Handbook 1990-2006 (oee.nrcan.gc.ca/corporate/statistics).

Average furnace age cross tabulated with dwelling age is provided in Exhibit 5.29.

Exhibit 5.29: Age of Furnace by Dwelling Construction Date
Natural Gas or Piped Propane

Age of Gas Furnace (years)	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 – 2005	2006 or later	2008 TG
Unweighted base	118	307	215	304	364	45	1353
Median	12.0	10.0	11.0	15.0	8.0	2.0	10.0
Mean	17.0	15.6	16.8	13.5	7.8	2.9	14.3
Standard deviation	15.8	17.9	14.0	7.0	3.1	0.2	13.8

Data for 2002 not available.

5.6.1 Furnace & Boiler Replacement Behaviours

On average, 22% of TG customers replaced their furnace or boiler in the last five years (Exhibit 5.30).

Exhibit 5.30: Installed Gas Furnace or Boiler in Last Five Years by Region (%)

Installed Furnace or Boiler?	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base [1]	463	629	316	124	133	1665	1225	1550
Yes	23.1	20.1	16.3	21.9	23.7	21.7	22.1	19.5
No	74.8	78.8	83.7	77.4	74.8	76.5	76.0	77.4
DK	2.2	1.0	0.1	0.8	1.5	1.7	1.8	3.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Asked only of those with a gas furnace or boiler.

The reasons for replacing a furnace are listed in Exhibit 5.31. Three reasons dominate: wanting a more efficient furnace or boiler (mentioned by 44% of TG customers replacing a furnace or boiler in last five years), failure of the existing furnace or boiler (22%), and anticipation that the furnace or boiler would fail (18%). The desire to switch to natural gas was mentioned by 22% of TGVI residents who replaced a furnace.

Exhibit 5.31: Reason for Installing Gas Furnace or Boiler (%)
Natural Gas or Piped Propane

Reasons	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base [1]	91	114	47	26	32	310	237	312
New home	7.8	10.1	12.3	19.5	9.4	8.6	8.4	15.3
Wanted to change to gas	--	--	22.1	3.9	--	1.2	--	5.9
Wanted more efficient furnace or boiler	42.5	52.3	30.0	15.6	34.4	44.3	45.2	25.7
Existing furnace or boiler had failed	24.6	15.1	17.7	34.6	34.4	21.8	22.0	35.6
Anticipated furnace or boiler failure	18.7	17.5	15.2	11.2	12.5	18.2	18.4	20.8
House was too cold	1.5	0.1	--	7.6	--	1.1	1.1	3.1
Heated floor area increased	--	2.4	--	7.6	--	0.6	0.7	1.4
Wanted an environmentally friendly fuel	3.2	0.1	--	--	--	2.2	2.3	1.9
Wanted a lower cost fuel	0.2	2.4	--	--	3.1	0.8	0.8	6.5
Other	1.5	--	2.7	--	6.3	1.2	1.1	1.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Exhibit 5.32 presents the efficiency level of furnaces replaced during the past five years. Fifty-one percent (51%) TG customers who installed a furnace in the last five years installed a mid-efficiency furnace, while 40% installed a high efficiency unit. A very small percentage (<1%) indicated their furnace was a standard efficiency unit, which is likely incorrect as current legislation prevents the sale of furnaces with efficiencies of less than 80%. Regional results are provided, but sample sizes are small and caution is advised in interpreting differences between the regions. Efficiency levels for boilers installed in the last five years are not reported due to small sample sizes.

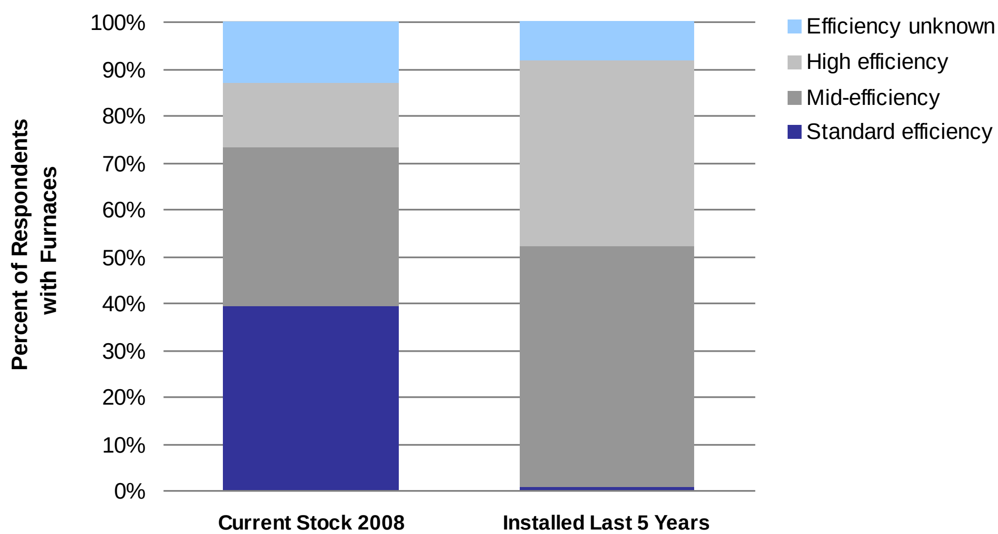
Exhibit 5.32: Efficiency of Gas Furnace Installed in Last Five Years (%)

Efficiency of New Furnace	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	72	111	33	16	32	264
Standard efficiency (<78% AFUE)	0.4	2.1	0.2	4.3	--	0.8
Mid-efficiency (80% to 85% AFUE)	54.0	45.4	47.3	50.0	61.6	51.3
High efficiency (90% AFUE or higher)	35.9	46.1	47.7	45.7	38.4	39.5
Efficiency unknown	9.7	6.4	4.8	--	--	8.4
Total furnaces	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Figure 5.1 compares the furnace efficiency mix for the stock of furnaces with that of those that have been installed in the last five years. The graphic clearly illustrates the influence of legislation limiting the sale of furnaces to either mid- or high efficiency units.

Figure 5.1: Furnace Efficiencies – Current Stock Versus Installed Last 5 Years



5.6.2 Furnace Pilot Light Behaviours

Pilot lights are used on standard efficiency furnaces, and consume energy throughout the non-heating season if not turned off. The 2008 REUS asked those TG customers with natural gas furnaces equipped with a pilot light to indicate the number of months in the year, if any, they turned off their pilot lights. A review of the responses clearly indicated that some respondents with mid or high efficiency furnaces responded to the question. As this would skew the means for this question, Exhibit 5.33 summarizes the data for only respondents who indicated they had a standard efficiency furnace.

Exhibit 5.33: Pilot Light Behaviours – Standard Efficiency Furnaces (%)
Natural Gas or Piped Propane Furnaces

Pilot light usage (turned off)	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	141	177	42	15	33	408
Never turned off	76.7	64.3	84.5	72.5	73.4	73.3
Turned off:						
1 month	--	--	--	6.9	--	0.0*
2 months	2.1	1.5	--	--	--	1.8
3 months	4.5	4.5	6.1	6.9	10.0	4.5
4 months	5.3	6.6	3.0	6.9	10.0	5.7
5 months	1.2	7.6	0.3	--	3.4	3.0
6 months	0.3	3.2	--	--	--	1.1
7 months	1.0	1.5	--	--	--	1.1
8 months	1.0	0.7	3.0	--	--	1.0
12 months	4.3	5.4	3.0	--	--	4.6
Turn off, not sure how long	1.3	2.3	--	6.9	--	1.6
DK	2.2	2.4	--	--	3.4	2.2
Total	100.0	100.0	100.0	100.0	100.0	100.0
Turn off, one or more months (%)	**21.1**	**33.3**	**15.5**	**27.5**	**23.3**	**24.5**
Mean # of months turned off	**5.8**	**5.8**	**6.0**	**2.7**	**3.7**	**5.6**

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
* Value less than 0.1%.

The data show that that 25% of TG customers with standard efficiency furnaces turn off their furnace's pilot light at least one month of the year and another 2% indicated they turned off their light but did not know for how many months. Seventy-three percent (73%) indicated their pilot light is never turned off. If turned off, pilot lights remain off for an average of six months of the year.

5.6.3 Furnace Maintenance Behaviours

The frequency in which four furnace maintenance behaviours were performed (always, usually, occasionally, or never) was queried, including:

- regularly changing the furnace filter;
- having the heating system serviced annually – by a contractor versus the homeowner; and
- duct cleaning.

The data, summarized in Exhibit 5.34, indicate that 51% of respondents always change their furnace filter on a regular basis. Considerably fewer respondents reported always having their heating system serviced annually by a contractor (23%), and fewer still indicated they conduct the servicing themselves (13%). Finally, only 9% of respondents indicated they always have their ducts cleaned.

Exhibit 5.34: Frequency of Actions to Conserve Energy – Heating System

Heating System Maintenance	Always	Usually	Occasionally	Never	DK	N/A
Change furnace filter regularly	50.5	25.2	8.8	1.9	1.2	12.3
Service heating system annually by contractor	22.5	19.9	29.5	22.4	1.8	3.8
Service heating system annually myself	13.3	13.2	15.2	46.5	0.9	10.9
Duct cleaning	8.6	12.2	36.3	27.4	2.6	12.9

6 FIREPLACES & HEATING STOVES

Compared to the two previous surveys, the 2008 REUS significantly revised the range of fireplace types queried, and expanded the fireplace section to include stand-alone heating stoves. This allowed respondents to categorize their fireplace(s) / heating stove (s) by both design and purpose. For example, gas fireplaces were either decorative (built-in), heating (built-in or inserts), or free standing. For each type, respondents were asked to indicate whether it was used for providing heat, ambience or a combination of the two. These revisions and additions provide a more comprehensive picture of this particular space heating end use.

6.1 Fireplace and Heating Stove Types

The following descriptions were provided to assist survey respondents in correctly categorizing their fireplace or heating stove:

- **Decorative fireplaces** – Provide ambience but have little or no heating ability. The firebox is typically steel or masonry, and the hearth is typically open to the room (no fixed glass front).

- **Heater type fireplaces (built-ins and inserts)** – These fireplaces are efficient heaters with glass fronts and may have features such as fans and thermostatic control. They may be built-in at the time of construction, or inserted into an existing masonry or other fireplace as an upgrade.

- **Free standing fireplaces and heating stoves** – These are stand-alone units that can be used for both ambience and heating. Gas heating stoves resemble wood stoves in appearance but use gas instead of wood.

6.2 Penetration and Saturation Rates

Exhibit 6.1 shows the penetration of fireplaces and heating stoves, regardless of the fuel used, is on an upward trend with 85% of TG and TGI households having at least one fireplace or heating stove in 2008, compared to 81% and 77% in 2002 and 1993 respectively. Saturation among TGI customers has increased from 1.2 fireplaces per household in 1993 to 1.5 in 2008.

Exhibit 6.1: Fireplaces and Heating Stoves by Region
All Fuel Types

	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	570	707	552	205	133	2167	1960	1610	4814
Penetration (%)	87.3	77.0	90.0	97.5	47.4	84.8	84.5	81.0	76.7
Saturation	1.55	1.37	1.74	1.52	0.65	1.52	1.50	1.31	1.21

To be consistent with past REUS studies, saturation and penetration rates for the different fireplace types and heating stoves are calculated using a base of fireplace and heater stove users, not the total population of those with and without. Some caution in interpreting these numbers is advised as the definitions and comprehensiveness of the fireplace section within the three REUS surveys has expanded in each survey round.

TG customers with a fireplace or heating stove are most likely to have a gas (heater type) fireplace (50% of users) (Exhibit 6.2). The next most common types include wood burning fireplaces (28%), and gas (decorative) fireplaces (22%). Electric fireplaces are present in 7% of homes, compared to 1% of houses with fireplaces in 2002. This increase is consistent with the increase in electric fireplaces available through home improvement / hardware stores during the past few years.

Regionally, customers in the INT and FN regions with fireplaces and heating stoves were more likely to have a wood stove (13% and 22% respectively) than other regions. Gas (heating type) fireplaces were most prevalent in TGVI (64%) and the least prevalent in FN (33%).

Exhibit 6.2: Fireplace and Heating Stove Details by Region

Fireplace / Heating Stove Type	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base[1]	502	543	497	200	64	1806
Gas (decorative)						
Penetration (%)	22.9	21.5	14.2	23.6	9.4	21.6
Saturation	0.38	0.30	0.38	0.34	0.05	0.35
Gas (heater type)						
Penetration (%)	49.3	46.3	64.3	48.8	32.8	50.1
Saturation	0.65	0.48	0.77	0.56	0.18	0.61
Gas (free standing)						
Penetration (%)	5.8	8.6	11.3	4.0	17.2	7.1
Saturation	0.05	0.12	0.14	0.05	0.10	0.08
Electric						
Penetration (%)	6.6	6.8	6.4	2.5	12.5	6.6
Saturation	0.08	0.08	0.11	0.03	0.06	0.08
Wood burning fireplace						
Penetration (%)	29.8	28.4	19.3	34.9	26.6	28.4
Saturation	0.37	0.26	0.27	0.41	0.16	0.33
Wood burning stove						
Penetration (%)	2.9	13.0	4.7	9.1	21.9	5.6
Saturation	0.03	0.12	0.07	0.10	0.10	0.06
Other						
Penetration (%)	0.8	0.3	0.6	1.5	--	0.7
Saturation	0.01	0.00 *	0.01	0.01	--	0.01

[1] All fireplace and heater stove users
* Value less than 0.01

Penetration of fireplaces and heating stoves was highest in VSDs (94%) and lowest in MFDs (82%) (Exhibit 6.3)

Exhibit 6.3: Fireplaces and Heating Stoves by Building Type (%)
All Fuel Types

	SFD	VSD	MFD	2008 TG
Unweighted base	1336	232	599	2167
Penetration (%)	84.9	94.3	82.2	84.8
Saturation	1.56	1.38	1.22	1.52

Among those with fireplaces and/or heating stoves, VSDs were much more likely to have a gas (heater type) fireplace (78%), while wood burning fireplaces were significantly more common among SFDs (30%) than other building types (Exhibit 6.4).

Exhibit 6.4: Fireplaces and Heating Stove Details by Building Type (%)

Fireplace / Heating Stove Type	SFD	VSD	MFD	2008 TG
Unweighted base	1096	217	493	1806
Gas (decorative)				
Penetration (%)	20.6	14.4	37.6	21.6
Saturation	0.26	0.17	0.42	0.35
Gas (heating type)				
Penetration (%)	50.0	78.3	49.9	50.1
Saturation	0.69	0.80	0.57	0.61
Gas (free standing)				
Penetration (%)	7.3	10.5	4.1	7.1
Saturation	0.08	0.12	0.04	0.08
Electric				
Penetration (%)	6.7	7.9	5.5	6.6
Saturation	0.09	0.14	0.06	0.08
Wood burning fireplace				
Penetration (%)	29.8	3.6	9.6	28.4
Saturation	0.38	0.05	0.11	0.33
Wood burning stove				
Penetration (%)	6.0	2.3	0.2	5.6
Saturation	0.06	0.04	0.00 *	0.06
Other				
Penetration (%)	0.6	1.5	0.7	0.7
Saturation	0.01	0.06	0.01	0.01

* Value less than 0.01

6.3 Usage Behaviours

6.3.1 Primary Purpose

Exhibit 6.5 summarizes how the different fireplace and heating stove types are used. To aid interpretation, the data was expressed graphically in Figure 6.1.

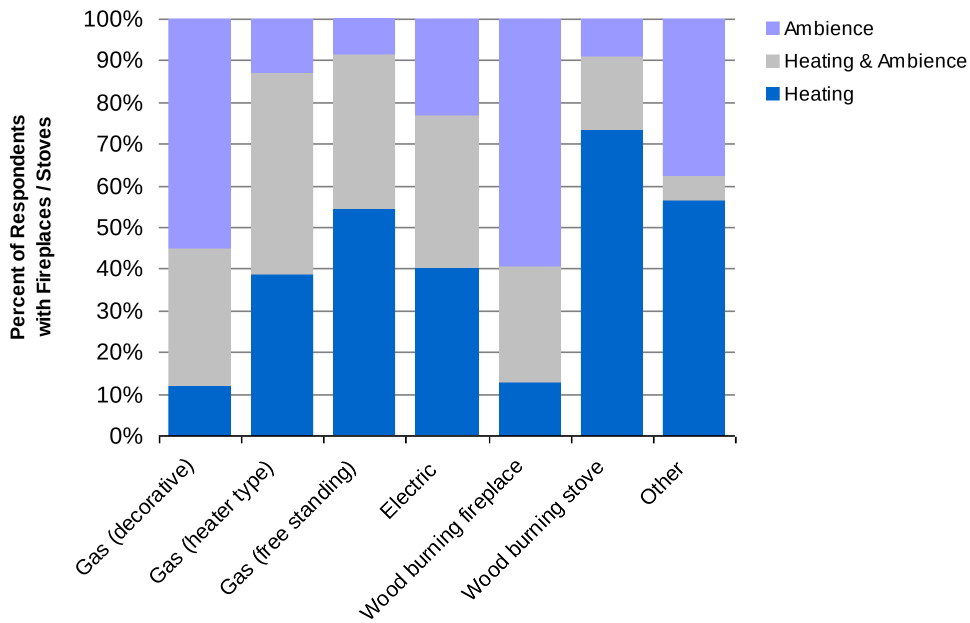
Exhibit 6.5: Use of Fireplaces and Heating Stoves (%)

Fireplace / Heating Stove Type	Heating	Ambience	Heating & Ambience	Total
Gas (decorative)	11.8	55.1	33.0	100.0
Gas (heater type)	38.5	12.9	48.6	100.0
Gas (free standing)	54.4	8.6	37.0	100.0
Electric	40.0	23.4	36.6	100.0
Wood burning fireplace	12.5	59.4	28.1	100.0
Wood burning stove	73.4	9.1	17.5	100.0
Other	56.4	37.6	6.0	100.0

Bases vary with each fireplace type.

The style of fireplace or heating stove appears consistent with their primary purpose (heating, ambience or some combination of the two). For example, 73% of customers with wood burning stoves used them primarily for heating. Conversely, the majority (55%) of customers with gas (decorative) fireplaces used them for ambience.

Figure 6.1: Primary Purpose of Fireplaces and Heating Stoves – 2008 REUS



6.3.2 Hours-of-Use

Average weekly hours of use for fireplaces and heating stoves by season and TG region are summarized in Exhibit 6.6. Not surprisingly, use of fireplaces / heating stoves was highest in the winter. Winter usage averaged 20 hours for TG and TGI customer groups. The difference in the winter use estimate between the 2002 and 2008 surveys is not statistically significant at the 95% confidence level. Average wintertime usage by region correlates with the regional climate and the penetration of fireplaces / heating stoves. For example, FN customers used their fireplaces and stoves the most (34 hours per week or 4.9 hours per day) and LM customers used theirs the least (17 hours per week or 2.5 hours per day). Similar regional relationships exist with the shoulder seasons (spring and fall). Based on seasonal averages, total fireplace and heating stove usage is highest in the FN region (766 hours per year), followed by TGVI (702 hours). Usage is lowest in the LM (393 hours).

Exhibit 6.6: Weekly Hours of Fireplace / Heater Stove Operation by Region

Season	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	570	707	552	205	133	2167	1960	1259
Summer	0.1	0.6	0.4	0.2	0.0	0.3	0.3	0.6
Fall	6.2	8.6	13.6	7.6	13.5	7.6	7.3	10.1
Winter	17.3	23.6	28.3	22.0	33.6	20.1	20.1	20.8
Spring	6.6	7.5	11.7	6.5	11.8	7.4	7.0	9.3
Annual Average Hours [1]	393	524	702	472	766	460	451	530

[1] Assumes each season is three months long.

Average annual use of fireplaces and heating stoves is significantly higher for VSDs (697 hours per year) than SFDs (459 hours) and MFDs (387 hours) (Exhibit 6.7). This is consistent with tendency for respondents in VSDs with gas fireplaces to use the fireplace as either the primary or secondary heating method (Exhibit 5.16,Exhibit 5.18).

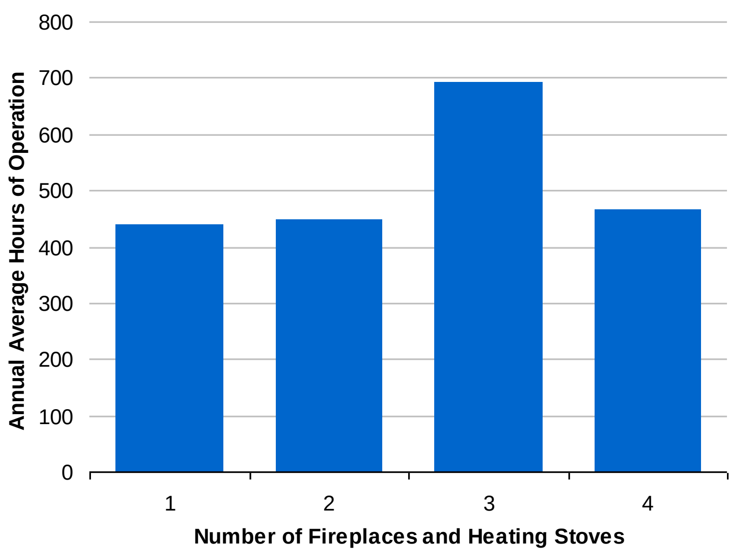
Exhibit 6.7: Weekly Hours of Fireplace / Heater Stove Operation by Building Type

Season	SFD	VSD	MFD	2008 TG
Unweighted base	1336	232	599	2167
Summer	0.3	0.4	0.1	0.3
Fall	7.5	13.5	6.1	7.6
Winter	20.2	28.1	17.2	20.1
Spring	7.3	11.6	6.4	7.4
Annual Average Hours [1]	459	697	387	460

[1] Assumes each season is three months long.

Figure 6.2 summarizes total annual household fireplace and heating stove operating hours by the number of fireplaces and heating stoves present in the residence. The data suggest that the presence of more than one fireplace and/or heating stove does not necessarily result in a proportionately equal increase in operating hours. It is likely that households with more than one fireplace and/or heating stove are using some units more frequently than others. The increase in total operating hours for homes with three fireplaces or heating stoves may be because they are using two out of their three fireplaces or stoves but using them individually less than households with only one fireplace or stove. The number of households with four fireplaces or heating stoves was small, so caution is recommended in the interpretation of the operating hour decrease for this group of respondents.

Figure 6.2: Annual Operating Hours by the Number of Fireplaces and Heating Stoves



Due to survey length limitations, respondents to the 2008 REUS were not asked to itemize hours-of-use for individual fireplaces and/or heating stoves. The next three exhibits explore differences in average weekly hours-of-use between the three gas fireplace types – decorative versus heater type versus free-standing – using data from respondents with only one gas fireplace (any type) and no other fireplace type (i.e., no wood or electric).[26]

[26] Homes with two or more different gas fireplace types, or homes with gas and electric fireplaces, or gas and wood fireplaces were excluded from this analysis because it was not possible to attribute hours of operation to individual fireplace types in multi-fireplace households.

The data show that decorative gas fireplaces are used the least (average of 293 hours per year) and free standing gas fireplaces / heating stoves are used the most (602 hours). Use of heater type gas fireplaces averaged 520 hours per year. Regional details are provided; however, caution is advised as some samples are small. Of note, usage hours for INT customers with either a decorative or heater type gas fireplace is lower than customers in the LM, but operating hours for all fireplace and heater stove types in the INT, as presented in Exhibit 6.6, is significantly higher than the LM. The explanation for this incongruous finding may be linked to INT region's significantly higher penetration of wood burning fireplaces and heating stoves (Exhibit 6.2, p. 6-2). The lower operating hours for gas fireplaces in INT may be because customers in this region tend to use their wood fireplaces to supplement their space heating relatively more than INT customers with natural gas fireplaces.

Exhibit 6.8: Average Weekly Hours by Region – Decorative Gas Fireplaces

Season	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	77	82	40	24	3	226
Summer	0.0*	0.0*	0.1	0.1	--	0.0*
Fall	7.3	0.7	11.5	4.4	--	5.6
Winter	15.0	4.5	19.4	16.1	9.8	12.2
Spring	6.0	0.5	10.4	2.7	--	4.7
Annual Average Hours [2]	368	74	538	303	127	293

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Assumes each season is three months long.
* Value less than 0.1 hour.

Exhibit 6.9: Average Weekly Hours by Region – Heater Type Gas Fireplaces

Season	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	169	210	235	62	15	691
Summer	0.5	0.0*	0.2	0.2	0.0	0.3
Fall	9.7	5.6	10.0	8.8	2.3	8.7
Winter	27.4	14.7	22.9	24.4	28.7	23.3
Spring	8.7	4.8	9.0	7.4	1.9	7.7
Annual Average Hours [2]	602	326	547	530	428	520

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Assumes each season is three months long.
* Value less than 0.1 hour.

Exhibit 6.10: Average Weekly Hours by Region – Free Standing Gas Fireplaces / Heating Stoves

Season	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	18	15	21	4	5	63
Summer	0.0	0.0	0.2	0.0	0.0	0.0*
Fall	3.8	22.5	15.6	3.9	18.9	11.5
Winter	7.6	44.9	47.2	23.1	57.7	26.2
Spring	1.5	17.5	14.1	3.9	18.9	8.6
Annual Average Hours [2]	168	1104	1002	402	1242	602

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Assumes each season is three months long.
* Value less than 0.1 hour.

6.3.3 Pilot Light Usage

Turning off the pilot light of a gas fireplace during the non-heating season can significantly reduce the amount of gas used by the fireplace. A study conducted in the 1990s for the Canadian Gas Association found that, if left on all year, the pilot light accounted for nearly half (48%) of the total annual gas consumption of a fireplace.[27]

Sixty-one percent (61%) of respondents with a gas fireplace (any type) using a pilot light indicated they turn off the pilot light at least one month per year (Exhibit 6.11). Another 2% said they turn off their gas fireplace pilot light but were unsure for how long. Pilot lights were off, on average, for 5 months per year. Of note, 28% of gas fireplace users reported never turning off their fireplace pilot light and 8% indicated they never light the pilot light.

Exhibit 6.11: Gas Fireplace Pilot Light Usage
Gas Fireplaces with a Pilot Light

Gas Fireplace Pilot Light Usage	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	374	375	401	134	30	1314
Never turned off	31.3	17.5	31.4	53.0	23.3	28.2
Turned off:						
1 month	--	0.5	0.8	--	--	0.2
2 months	2.2	1.4	0.9	0.8	3.3	1.9
3 months	3.6	4.4	5.6	0.0	6.7	4.0
4 months	9.4	6.4	9.7	4.5	10.0	8.7
5 months	7.8	6.4	11.0	7.4	--	7.9
6 months	9.5	19.2	11.9	12.0	16.7	12.0
7 months	1.4	8.7	4.4	5.1	10.0	3.5
8 months	5.2	8.4	5.0	4.5	3.3	5.9
9 months	2.6	2.0	3.2	3.1	6.7	2.5
10 months	4.6	4.5	3.5	0.8	--	4.4
11 months	1.2	2.4	0.8	--	--	1.4
12 months	8.4	8.5	6.9	4.5	10.0	8.2
Turn off, not sure how long	1.5	1.6	0.8	1.7	1.4	1.5
DK	4.2	1.9	--	0.8	3.3	3.2
Total	100.0	100.0	100.0	100.0	100.0	100.0
Turn off, one or more months (%)	**55.8**	**72.7**	**63.6**	**42.5**	**66.6**	**60.7**
Mean # of months turned off	**4.4**	**5.6**	**4.3**	**3.0**	**4.9**	**4.7**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Regionally, TGW customers are the most likely to leave their fireplace pilot light turn on all year (53%) compared to INT customers, who are the least likely to leave their pilot on all year (18%). Customers in the LM and TGVI regions are tied with 31% in each region leaving their pilot lights on 12 months of the year.

Based on these data, it is estimated that 89% of gas fireplaces in the TG regions use pilot lights.[28]

[27] Pilot lights left on for 12 months of the year were found to consume 8 GJ of gas. Source: Research conducted for the Canadian Gas Association by Advanced Combustion Technologies of CANMET, Ottawa, Ontario, as reported in the January / February 1997 issue of *Home Energy Magazine Online*.

[28] Calculated as the number of respondents with a gas fireplace using a pilot light (QC4), divided by number of respondents indicating the presence of at least one gas fireplace (QC2).

7 DOMESTIC HOT WATER

TG customers were asked a series of questions regarding their hot water heating, including appliance type, fuel, equipment vintage, replacement frequency, and reasons for replacement.

7.1 Penetration and Saturation Rates

The 2008 survey identified that 3.5% of respondents did not have a water heater in their residence. These include residences such as apartments, townhouses, or row houses where the hot water is centrally provided to the unit (i.e., from outside the unit). Saturation rates for hot water heaters exclude these respondents. The 2002 study treated these customers as non-responses.

The penetration and saturation rates for hot water heaters by TG region are summarized in Exhibit 7.1. Ninety-seven (97%) of TG customers have at least one hot water heater. There are no statistically significant variations in penetration by region. Overall saturation was 1.03 water heaters per household, and reflects the small percentage (3%) of households that have more than one water heater. Of note, 23% of TGW customers reported more than one hot water heater. This is attributed to the high proportion of homes in the community that have a secondary suite.[29] Saturation rates are unchanged from 2002 and 1993. Thirty-eight percent (38%) of TG customers installed a hot water heater in the last five years. This is equivalent to a replacement rate of 8% per year, and an average life of over 13 years.

Exhibit 7.1: Hot Water Heaters by Region

	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	567	721	555	208	135	2186	1423	1610	4814
Penetration (%)	95.9	97.1	98.7	96.3	98.0	96.5	95.9	94.6	92.1
Saturation [1]	1.02	1.04	1.04	1.25	1.02	1.03	1.03	1.03	1.03
Households with >1 water heater (%) [1]	2.5	4.1	3.7	23.1	2.1	3.1	3.0	2.7	n/a
Installed new water in past five years (%) [1]	40.2	31.7	44.6	40.0	39.8	38.3	37.6	37.2	n/a
No hot water heater in residence (%)	4.1	2.9	1.3	3.7	2.0	3.5	3.7	5.4 [2]	5.4 [2]

[1] Excludes respondents living in apartments, row houses and townhouses where hot water is centrally provided.
[2] Includes non-responses. Including non-responses , the percentage of TGI customers with no water heater increases 4.9%, closer to the 2002 and 1993 estimates.

Comparable water heating penetration and saturation data by building type are provided in Exhibit 7.2. Of note, VSDs are significantly more likely than SFDs and MFDs to have their domestic hot water provided centrally (47% versus 3% and 4% respectively).

SFDs and MFDs are statistically identical in their frequency of water heater installation in the past five years (38% for both). Significantly fewer respondents living in VSDs replaced their hot water tank in the same period (19%). This is consistent with the tendency for VSD buildings to be considerably newer, on average, than the other two building types, meaning that the age of hot water tanks is younger as well.

[29] Suggested by a plumbing and heating contractor based in Whistler.

Exhibit 7.2: Hot Water Heaters by Building Type

	SFD	VSD	MFD	2008 TG
Unweighted base	1349	234	603	2186
Penetration (%)	96.8	53.9	95.7	96.5
Saturation [1]	1.03	1.10	1.03	1.03
Households with >1 water heater (%) [2]	3.1	8.3	2.8	3.1
Installed new water in past five years (%) [1]	38.4	19.2	37.8	38.3
No hot water heater in residence (%)	3.2	47.2	4.3	3.5

[1] Excludes respondents living in apartments, row houses and townhouses where hot water is centrally provided.

7.2 Average Age of Hot Water Heaters

The average age of hot water heaters across the five TG regions is 7.1 years (Exhibit 7.3). The average age of hot water heaters for TGI customers is effectively unchanged from the previous survey in 2002. Consistent with the significantly lower replacement rate in the INT region (Exhibit 7.1), the average age of their hot water heater (9.1 years) is significantly higher than the other regions. Due to the small number of households (3%) with more than one water heater, caution is advised in the interpretation of age estimates for the second water heater unit.

Exhibit 7.3: Average Age of Hot Water Heaters by Region

	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	385	537	452	178	104	1656	1026	1528	4814
Age of first water heater	6.5	9.1	5.7	6.8	5.8	7.1	7.3	7.5	6.4
Age of second water heater	5.2	7.0	9.8	7.8	-- [1]	6.7	6.2	8.5	7.4

[1] No Fort Nelson respondents indicated they had a second water heater

7.3 Water Heater Fuels

The fuels used for water heating were queried. As some residences have more than one water heater, fuel use was queried for up to three different water heaters. These data should be viewed with some caution as a comparison of water heater data by fuel versus equipment type revealed that some respondents had difficulty either correctly identifying the fuel used for water heating or the water heater type (e.g., conventional electric storage versus conventional gas storage). Additional discussion of this issue is provided on page 7-5.

The fuels used for the first water heater are summarized in Exhibit 7.4. Natural gas is the predominant fuel, accounting for 89% of first hot water heaters in the TG region. The use of natural gas for water heating by TGI customers increased from 85% in 2002 to 90% in 2008.

Consistent with the survey results for space heating fuel, a portion (12%) of TGW respondents indicated they have access to natural gas, a service not available at the time of the survey. This mistake is relevant for Terasen as it is evident that a significant percentage of their TGW customers mistakenly believe they are currently receiving natural gas service.

Exhibit 7.4: Hot Water Heater Fuel by Region – First Unit (%)

Fuel for First Water Heater	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	481	679	536	199	131	2026	1291	1528	3557
Electricity	8.9	11.4	20.0	43.5	12.8	10.8	9.7	14.3	14.3
Natural gas	90.8	88.6	79.5	12.1	87.2	88.8	90.1	84.7	84.3
Piped propane	--	0.0*	0.3	44.0	--	0.1	0.0*	0.2	0.2
Other	0.3	--	0.3	0.5	--	0.2	0.2	--	0.2
NR	--	--	--	--	--	--	--	0.9	1.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
* Value smaller than 0.1%

Fuel use for the second water heater is summarized in Exhibit 7.5. As the samples are small, only the results for TG and TGI are presented.

Exhibit 7.5: Hot Water Heater Fuel – Second Unit (%)

Fuel for Second Water Heater	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base [1]	109	43	44	83
Electricity	26.9	24.4	14.3	33.8
Natural gas	72.6	75.6	78.4	64.6
Piped Propane	0.5	--	--	--
Other	--	--	3.6	1.6
NR	--	--	3.6	--
Total	100.0	100.0	100.0	100.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Natural gas is the dominant fuel choice for water heating for the three building types, although VSDs are significantly more likely than SFDs and MFDs to use electric hot water heaters (Exhibit 7.6). Data for second units are not reported due to very small sample sizes.

Exhibit 7.6: Hot Water Heater Fuel by Building Type - First Unit (%)

Fuel for First Water Heater	SFD	VSD	MFD	2008 TG
Unweighted base	1304	152	570	2026
Electricity	10.7	27.2	11.1	10.8
Natural gas	88.9	72.8	88.3	88.8
Piped Propane	0.1	--	0.6	0.1
Other	0.3	--	--	0.2
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

A very small percentage (0.8%) of Terasen Gas customers use solar energy to pre-warm or supplement their water heating process (Exhibit 7.7). Differences between the regions are not significant at the 95% confidence level.

Exhibit 7.7: Solar Assist for Pre-Warming Hot Water Heater by Region - First Unit (%)

	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	460	639	511	196	122	1928
Use solar assist	0.8	1.0	0.6	0.5	2.4	0.8
No assist	99.2	99.0	99.4	99.5	97.6	99.2
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

7.3.1 Fuel Switching

A very small percentage of TG customers (1%) changed their hot water heating fuel during the last five years (Exhibit 7.8). Of note, 6% of TGVI customers and 3% of TGW customers changed fuels. Comparing results for TGI customers with the 2002 and 1993 suggests that the incidence of fuel switching for hot water heating purposes has decreased.

Exhibit 7.8: Changed Hot Water Heater Fuel Last Five Years

Changed water heater fuel last five years?	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	475	673	527	199	130	2004	1278	1516	4814
Yes	--	1.6	6.4	2.5	--	1.1	0.5	5.7	2.9 [1]
No	100.0	98.4	93.6	97.5	100.0	98.9	99.5	94.3	97.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] 1993 survey asked for fuel changes in the last two years

Although the samples are very small, Exhibit 7.9 summarizes the before and after fuel choices for customers that switched their hot water heater fuels during the last five years. Of those who switched to natural gas, 78% previously used electricity and 22% used oil. The majority of those who switched to electricity, used natural gas with their earlier hot water heater. One respondent with a natural gas fired heater and an electric hot water heater, indicated both had been switched from electricity. It was assumed that the natural gas heater had replaced an electric heater.

Exhibit 7.9: Water Heating Fuel Change During Past Five Years (%)

Current fuel \ Previous fuel	Electricity	Natural Gas	Piped Propane	Oil	Total
Unweighted base [1]	22	11	3	7	43
Electricity	--	98.6	1.4	--	100.0
Natural gas	78.1	--	--	21.9	100.0
Piped propane	--	100.0	--	--	100.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

7.3.2 Hot Water Fuel and Space Heating Fuel Combinations

Exhibit 7.10 summarizes the combinations of main space heating fuel and water heating fuel (first water heater). The most common combination is gas for both space heating and water heating (81% of all TG respondents). Five percent (5%) of respondents indicated they have electric heat and a gas hot water heater. Conversely, 8% of respondents with natural gas or propane as their main space heating fuel indicated they had an electric hot water heater. Four percent (4%) of respondents did not have a hot water heater (i.e., hot water is centrally provided).

Exhibit 7.10: Water Heating and Space Heating Fuel Combinations (%)

Hot Water Fuel \ Space Heating Fuel	Electricity	Gas (Natural Gas or Propane)	Oil	Wood	Other	DK	Row Total
Electricity	2.0	7.9	0.1	0.4	0.0*	0.1	10.4
Gas (natural gas or propane)	4.6	80.5	0.1	0.5	0.2	0.0*	85.9
Oil	0.0*	0.2	0.0*	--	--	--	0.2
No hot water heater	0.4	3.2	--	--	0.0*	--	3.6
Column Total	7.1	91.8	0.1	0.9	0.2	0.1	100.0

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
* Less than 0.1 percent

7.4 Water Heater Types

The water heating section of the 2008 REUS was expanded to capture information on the penetration and saturation of water heaters by type of water heater. Five different types of water heaters were queried:

- storage tanks – vent through the roof
- storage tanks – vent through side wall
- storage tanks – no vent
- tankless or instantaneous
- combined space and water heater (boiler)

Exhibit 7.11 summarizes the relative distribution of hot water heaters by type of heater, regardless of the number of water heaters per household. The data show that the traditional storage tank with the vent through the roof is the most common water heater type among TG customers (57% of hot water heaters). Storage tanks with the vent through the sidewall of the home accounted for 11% of all TG customers. Storage style tanks with no vent (i.e., electric hot water heater tanks) are used by 14% of TG customers. Tankless or instantaneous water heaters account for 3% of all heater units. The TGW region is notable for its significantly higher proportion of electric storage tanks (33%) compared to the other four regions. Fourteen percent (14%) of TG customers, on average, were unsure of their water heater style.

Exhibit 7.11: Hot Water Heater Types by Region – Penetration Rates (%)

Hot Water Heater Type	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	463	653	525	195	127	1963
Storage water heater (tank) – vent through roof	55.0	64.5	45.0	21.5	58.9	56.5
Storage water heater (tank) – vent through side wall	11.1	9.0	19.7	28.4	10.8	11.4
Storage water heater (tank) – no vent	13.5	13.2	18.6	33.1	12.4	14.0
Tankless (instantaneous) water heater	3.3	1.5	2.6	1.6	3.1	2.7
Combined space & water heater	0.8	0.7	0.1	2.6	--	0.7
Condensing water heater	0.7	1.4	1.7	0.5	0.8	1.0
Don't know	15.6	9.7	12.4	12.3	14.0	13.6
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Comparing respondents' answers to their hot water heater fuel and water heater type reveals that some respondents had difficulty correctly identifying their hot water heater fuel and/or type. For example, 24% of respondents who said their hot water heater used electricity, indicated their tank had a vent through the roof or sidewall of the house (electric hot water heaters do not require a vent or flue), and another 17% were unsure of their tank design. A very small percentage (0.2%) said their heater was the tankless (instantaneous) design. It may be that some respondents with electric hot water tanks confused the vent /

flue for their furnace with that of their water heater, or that they were mistaken on the fuel used to heat their hot water. It is not possible to determine whether the error lies with mistaking the fuel or the heater type, or some combination of the two.

Saturation rates by type of hot water tank are provided in Exhibit 7.12. Saturation is highest for hot water heater tanks with a vent through the roof (0.64 units per Terasen customer). As this is the first year in which this question was asked, comparisons with the 2002 and 1993 survey years are not possible.

Exhibit 7.12: Hot Water Heater Saturation Rates by Region

Hot Water Heater Type	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	463	653	525	195	127	1963
Storage water heater (tank) - vent through roof	0.63	0.71	0.49	0.26	0.64	0.64
Storage water heater (tank) - vent through side wall	0.13	0.10	0.23	0.39	0.12	0.13
Storage water heater (tank) - no vent	0.15	0.15	0.22	0.48	0.14	0.16
Tankless (instantaneous) water heater	0.04	0.02	0.04	0.02	0.02	0.03
Combined space & water heater	0.01	0.01	--	0.02	--	0.01
Condensing water heater	0.01	0.02	0.02	--	--	0.01

Totals may not sum due to rounding.

7.5 Water Heater Installations

Thirty-eight percent (38%) of TG and TGI customers installed a new water heater in the last five years (Exhibit 7.13). This proportion is not significantly different from the 2002 estimate at the 95% confidence level.

Exhibit 7.13: Installed a New Water Heater in Past Five Years (%)

Installed Water Heater	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	482	670	531	197	131	2011	1283	1525
Yes	40.2	31.7	44.6	40.0	39.8	38.3	37.6	39.3
No	59.8	68.3	55.4	60.0	60.2	61.7	62.4	57.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Data for 1993 unavailable.

Water heater failure persists as the most commonly indicated reason for replacing a water heater, highlighted by 66% of TGI customers in the 2008 survey and 67% of TGI respondents in the 2002 survey (Exhibit 7.14). Another 18% of TGI respondents replaced their heater because of anticipated failure of the appliance. The 2002 data include multiple responses so comparisons with the 2008 data should be made with caution.

Exhibit 7.14: Main Reason for Installing a New Water Heater in Past Five Years (%)

Reason	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI [2]
Unweighted base	181	187	230	79	53	730	421	583
Water heater had failed	68.8	58.3	58.0	59.7	60.4	65.1	66.1	67.3
Anticipated water heater failure	17.5	17.7	16.9	23.7	9.4	17.5	17.5	16.8
Wanted more efficient water heater	8.7	12.5	6.2	5.1	11.3	9.2	9.6	3.7
New home	3.7	5.4	6.3	5.2	7.5	4.4	4.1	6.7
Wanted to change to gas	0.8	--	8.0	--	--	1.5	0.6	2.3
Needed more hot water	0.1	2.3	1.8	1.2	5.7	0.8	0.7	2.9
Wanted quicker hot water recovery	0.1	0.8	0.1	--	1.9	0.3	0.3	1.0
Wanted environmentally friendly fuel [1]	--	--	--	--	--	--	--	0.5
Wanted a cheaper fuel	0.1	--	0.6	--	--	0.2	0.1	0.8
Other	0.1	3.0	2.1	5.1	3.8	1.0	0.9	2.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	--

[1] No respondents to the 2008 survey selected this category
[2] Multiple responses allowed, values sum to more than 100%

7.6 Hot Water Appliances

Exhibit 7.15 summarizes the penetration and saturation of showerheads (any type), low flow showerheads, and water heater blankets. Comparisons between the 2002 and 2008 surveys are provided for TGI customers. Respondents to the 2002 REUS with more than four showerheads, low flow shower heads, and/or water heater blankets could only indicate this by checking a box labelled “4+”. The 2008 survey did not constrain respondents’ answers. As a result, the 2002 REUS saturation estimates for these three end uses may be understated.

Exhibit 7.15: Hot Water Appliances by Region

Hot Water Appliance	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	569	720	558	206	134	2187	1423	1610
Showerheads								
Penetration (%)	99.6	98.8	99.4	100.0	100.0	99.4	99.4	98.6
Saturation	2.23	2.00	1.99	2.66	1.85	2.15	2.16	1.95
Low flow showerheads								
Penetration (%)	42.9	54.6	51.1	48.6	44.1	46.9	46.4	61.6
Saturation	0.77	1.00	0.96	1.10	0.75	0.85	0.84	1.08
Water heater blankets								
Penetration (%)	4.9	9.0	8.7	6.4	4.4	6.4	6.1	15.2
Saturation	0.06	0.11	0.09	0.08	0.05	0.08	0.08	0.16

Penetration and saturation rates for low flow showerheads and hot water heater blankets are lower in 2008 compared to 2002. Low flow showerheads were reported by 46% of TGI customers in 2008 versus 62% in 2002. The difference between the two survey years is statistically significant at the 95% confidence level. The lower saturation rate for low flow showerheads may be attributed to the changing definition of what constitutes a low flow showerhead, with the flow rate for many standard showerheads equivalent to the older low flow units. Penetration of low flow showerheads is highest in the INT and TGVI regions, and lowest in the LM region.

Six percent (6%) of TGI customers reported using a hot water heater blanket, down from 15% in 2002. The lower penetration of water heater blankets is consistent with the gradual replacement of older water heaters with more efficient units (38% of 2008 REUS respondents installed a new water heater in the last five years). Newer water heaters are built with higher insulation levels and, as a result, the addition of a water heater blanket is not as cost-effective as with older units.

Penetration and saturation rates for the three hot water appliances by the three building types are provided in Exhibit 7.16.

Exhibit 7.16: Hot Water Appliances by Building Type

Hot Water Appliance	SFD	VSD	MFD	2008 TG
Unweighted base	1353	235	599	2187
Showerheads				
Penetration (%)	99.4	99.9	98.8	99.4
Saturation	2.14	1.99	2.21	2.15
Low flow showerheads				
Penetration (%)	47.1	40.5	44.3	46.9
Saturation	0.87	0.96	0.77	0.85
Water heater blankets				
Penetration (%)	6.4	0.9	5.7	6.4
Saturation	0.08	0.09	0.06	0.08

8 APPLIANCES

Respondents to the 2008 REUS were provided with a list of cooking, cooling, cleaning, and air conditioning and heating appliances and asked to indicate the number (quantity), and ages for those present in the residence. The saturation and penetration of each appliance was calculated, and the results for TGI customers compared with comparable data from the 2002 and 1993 surveys. The list of of appliances queried in the 2008 REUS is more extensive than in past surveys, so a multi-year analysis of penetration and saturation trends was not possible for all appliances.

8.1 Cooking Appliances

Exhibit 8.1 summarizes the penetration and saturation rates by appliance for the five TG regions, and compares 2008 TGI results with the estimates from 2002 and 1993.

Exhibit 8.1: Cooking Appliances by Region

Cooking Appliance	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	574	728	566	208	137	2213	1439	1610	4814
Electric range									
Penetration (%)	73.8	81.5	70.3	62.1	76.3	75.5	76.1	81.8	77.9
Saturation	0.86	0.88	0.77	0.65	0.82	0.86	0.87	0.92	0.87
Gas range									
Penetration (%)	18.8	12.3	24.0	30.1	18.7	17.6	16.8	15.7	9.1
Saturation	0.21	0.13	0.24	0.33	0.20	0.19	0.19	0.17	0.10
Electric cook top									
Penetration (%)	12.5	13.7	10.4	17.8	22.9	12.7	12.9	16.6	11.8
Saturation	0.14	0.14	0.11	0.19	0.24	0.13	0.14	0.19	0.13
Gas cook top									
Penetration (%)	10.9	6.6	9.4	26.3	9.2	9.6	9.6	7.0	3.1
Saturation	0.12	0.07	0.10	0.27	0.09	0.11	0.11	0.07	0.03
Electric wall oven									
Penetration (%)	14.5	11.7	11.5	26.7	8.6	13.5	13.6	n/a	n/a
Saturation	0.17	0.14	0.13	0.30	0.09	0.16	0.16	n/a	n/a
Gas wall oven									
Penetration (%)	3.6	0.5	1.8	5.0	0.6	2.6	2.7	n/a	n/a
Saturation	0.06	0.01	0.02	0.05	0.01	0.04	0.04	n/a	n/a
Microwave oven									
Penetration (%)	85.2	89.1	86.4	83.8	89.2	86.4	86.4	92.7	79.4
Saturation	1.00	0.95	0.96	0.95	0.96	0.98	0.98	1.01	1.04
Gas barbeque (piped gas) [1]									
Penetration (%)	11.9	20.4	23.6	42.8	12.2	15.5	14.5	9.7	4.5
Saturation	0.12	0.21	0.24	0.43	0.12	0.16	0.15	0.10	0.05
Gas barbeque (bottled gas) [2]									
Penetration (%)	49.8	49.1	42.0	33.6	60.4	48.8	49.6	63.0	51.7
Saturation	0.53	0.51	0.44	0.34	0.63	0.51	0.52	0.65	0.56

[1] This category was described as "NG barbeque" in the 2002 and 1993 REUS questionnaires.
[2] This category was described as "propane barbeque" in the 2002 and 1993 REUS questionnaires.
n/a = appliance not queried

Of note, the penetration of gas ranges for TGI customers has increased from 9% in 1993 to 17% in 2008, and the saturation rate is now 0.19, up from 0.10 in 1993. Gas cook tops also increased their share of the market, present in 10% of TGI residences, up from 3% in 1993.

Regionally, the penetration of gas cook tops and ranges and is highest among TGW customers (26% and 30% respectively) and lowest among INT customers (7% and 12%).

After increasing from 79% to 93% between 1993 and 2002, penetration of microwave ovens declined to 86% in 2008. Saturation also declined modestly.

Gas barbeques using piped gas have increased their penetration, rising from 5% of TGI residences in 1993, to 15% in 2008. The trend towards gas cooking appliances is consistent with the broader trend toward designer / gourmet kitchen designs and renovations, and the use of gas grills as the focal point in outdoor kitchens.[30]

Cooking appliance penetration and saturation rates by building type are summarized in Exhibit 8.2. Compared to SFDs and MFDs, VSDs are significantly more likely to use a gas range or gas cook top (46% and 39% respectively) rather than an electric range (38%).

Exhibit 8.2: Cooking Appliances by Building Type

Cooking Appliance	SFD	VSD	MFD	2008 TG
Unweighted base	1364	240	609	2213
Electric range				
Penetration (%)	75.0	37.8	85.1	75.5
Saturation	0.85	0.39	0.95	0.86
Gas range				
Penetration (%)	17.8	45.9	12.7	17.6
Saturation	0.20	0.46	0.13	0.19
Electric cook top				
Penetration (%)	12.3	11.8	17.6	12.7
Saturation	0.13	0.12	0.21	0.13
Gas cook top				
Penetration (%)	9.6	38.5	7.4	9.6
Saturation	0.11	0.41	0.08	0.11
Electric wall oven				
Penetration (%)	13.7	18.5	10.4	13.5
Saturation	0.16	0.19	0.11	0.16
Gas wall oven				
Penetration (%)	2.4	10.1	4.4	2.6
Saturation	0.04	0.10	0.05	0.04
Microwave oven				
Penetration (%)	86.5	86.5	84.1	86.4
Saturation	0.98	0.89	0.91	0.98
Gas barbeque (piped gas) [1]				
Penetration (%)	15.8	17.0	10.3	15.5
Saturation	0.16	0.19	0.10	0.16
Gas barbeque (bottled gas) [2]				
Penetration (%)	49.2	34.9	45.2	48.8
Saturation	0.52	0.35	0.46	0.51

[1] This category was described as “NG barbeque” in the 2002 and 1993 REUS questionnaires.
[2] This category was described as “propane barbeque” in the 2002 and 1993 REUS questionnaires.

[30] The past several years have seen the growth in the popularity of the outdoor kitchen: an outdoor eating area utilizing high-end gas appliances, including barbeques and cook tops, clean-up stations, and ambient lighting.

Exhibit 8.3 summarizes the average age of cooking appliances (first appliance only).

Exhibit 8.3: Average Age (Years) of Cooking Appliances (First Appliance)

Cooking Appliance	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Electric range	10.2	9.2	9.2	9.5	8.6	9.8	9.9	10.6	10.3
Gas range	8.3	9.5	8.0	8.9	9.1	8.5	8.6	9.2	9.9
Electric cook top	9.1	8.9	10.4	9.2	8.5	9.2	9.0	10.0	6.2
Gas cook top	6.4	8.3	8.8	7.3	7.9	7.0	6.8	8.5	6.1
Electric wall oven	9.8	9.2	10.4	9.9	11.3	9.7	9.7	n/a	n/a
Gas wall oven	5.8	2.9	14.2	8.9	3.0	6.4	5.8	n/a	n/a
Microwave oven	6.8	7.1	6.8	8.0	6.1	6.9	6.9	7.9	6.1
Gas barbeque (piped gas) [1]	7.1	6.2	5.6	6.7	5.3	6.5	6.7	5.6	4.0
Gas barbeque (bottled gas) [2]	5.3	5.7	5.5	6.1	5.4	5.4	5.4	6.7	5.2

[1] This category was described as "NG barbeque" in the 2002 and 1993 REUS questionnaires.
[2] This category was described as "propane barbeque" in the 2002 and 1993 REUS questionnaires.
n/a = appliance not queried

8.2 Cooling Appliances

Penetration and saturation rates for refrigerators and stand-alone freezers are not statistically different from those recorded in the 2002 survey. TGW customers had the lowest penetration rate for freezers (33%) and INT and FN customers had the highest rate (76%).

Exhibit 8.4: Cooling Appliances by Region

Cooling Appliance	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	574	728	566	208	137	2213	1439	1610	4814
Refrigerator									
Penetration (%)	96.4	97.8	94.6	97.1	97.2	96.6	96.8	97.7	n/a
Saturation	1.39	1.29	1.20	1.23	1.21	1.34	1.36	1.32	n/a
Stand-alone freezer									
Penetration (%)	63.6	75.4	63.9	32.9	76.1	66.7	67.1	69.4	n/a
Saturation	0.72	0.90	0.70	0.34	0.89	0.76	0.77	0.76	n/a

n/a = appliance not queried

Penetration and saturation rates for cooling appliances, organized by building type, are presented in Exhibit 8.5. Of note, VSDs are significantly less likely to have a stand-alone freezer than SFDs and MFDs.

Exhibit 8.5: Cooling Appliances by Building Type

Cooling Appliance	SFD	VSD	MFD	2008 TG
Unweighted base	1364	240	609	2213
Refrigerator				
Penetration (%)	96.5	98.7	97.0	96.6
Saturation	1.36	1.03	1.16	1.34
Stand-alone freezer				
Penetration (%)	67.8	27.1	54.1	66.7
Saturation	0.78	0.28	0.57	0.76

The average ages of refrigerators and stand-alone freezers are summarized by region in Exhibit 8.6.

Exhibit 8.6: Average Age (Years) of Cooling Appliances (First Appliance)

Cooling Appliance	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Refrigerator	8.4	8.4	8.2	8.7	8.0	8.4	8.4	8.7	n/a
Stand-alone freezer	12.7	13.5	11.6	10.1	10.3	12.9	13.0	13.7	n/a

n/a = appliance not queried

8.3 Cleaning Appliances

Cleaning appliances include automatic dishwashers, top loading and front loading (horizontal axis) clothes washers, and electric and gas clothes dryers. Penetration and saturation rates for these appliances for the 2008, 2002 and 1993 survey years are summarized in Exhibit 8.7.

Of note, the penetration of front-loading clothes washers has increased significantly in the past six years, rising from 9% of all TGI customers in 2002 to 27% in 2008. Commensurate with this increase, the penetration rate of top loading clothes washers has declined from 95% of TGI households in 1993 to the current 71%. Penetration of gas clothes dryers among TG customers is 6%. The penetration of gas clothes dryers is highest in the TGVI region (13%) and lowest in the LM region (5%).

Exhibit 8.7: Cleaning Appliances by Region

Cleaning Appliance	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	574	728	566	208	137	2213	1439	1610	4814
Dishwasher									
Penetration (%)	81.3	81.5	86.3	94.3	79.7	81.9	81.4	81.2	68.2
Saturation	0.87	0.84	0.91	1.04	0.82	0.87	0.86	0.83	0.69
Top loading clothes washer									
Penetration (%)	71.8	69.2	67.4	68.2	71.9	70.7	71.0	88.3	95.2
Saturation	0.76	0.71	0.68	0.72	0.73	0.74	0.75	0.90	0.96
Front loading clothes washer									
Penetration (%)	25.9	28.7	33.3	32.9	27.9	27.4	26.8	9.4	n/a
Saturation	0.29	0.30	0.34	0.35	0.30	0.30	0.29	0.10	n/a
Electric clothes dryer									
Penetration (%)	87.2	88.7	81.9	86.9	89.2	87.1	87.7	89.6	90.8
Saturation	0.92	0.92	0.84	0.94	0.92	0.91	0.92	0.91	0.92
Gas clothes dryer									
Penetration (%)	5.0	5.5	13.3	6.4	8.6	5.9	5.1	5.3	3.9
Saturation	0.06	0.06	0.14	0.06	0.09	0.07	0.06	0.05	0.04

n/a = appliance not queried

Penetration and saturation rates for cleaning appliances by the three building types are summarized in Exhibit 8.8. Of note, dishwashers have their lowest penetration in SFDs (81%) and the highest in VSDs (95%). Front loading clothes washers also are more prevalent in VSDs (36%) compared to SFDs (27%).[31] The relatively higher penetration of these two appliances in VSDs is consistent with the relative newness of the buildings in this dwelling category.

[31] Difference is statistically significant at the 90% interval.

Exhibit 8.8: Cleaning Appliances by Building Type

Cleaning Appliance	SFD	VSD	MFD	2008 TG
Unweighted base	1364	240	609	2213
Dishwasher				
Penetration (%)	81.4	94.7	88.2	81.9
Saturation	0.86	0.95	0.92	0.87
Top loading clothes washer				
Penetration (%)	70.7	67.1	70.6	70.7
Saturation	0.74	0.67	0.74	0.74
Front loading clothes washer				
Penetration (%)	27.3	35.5	28.2	27.4
Saturation	0.30	0.35	0.28	0.30
Electric clothes dryer				
Penetration (%)	87.0	93.9	87.7	87.1
Saturation	0.92	0.95	0.90	0.91
Gas clothes dryer				
Penetration (%)	6.1	3.4	3.8	5.9
Saturation	0.07	0.03	0.04	0.07

The average ages of cleaning appliances (first unit only) are summarized by appliance and region.

Exhibit 8.9: Average Age (Years) of Cleaning Appliances (First Appliance)

Cleaning Appliance	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Dishwasher	7.8	7.7	7.4	8.3	6.4	7.7	7.8	8.4	7.1
Top loading clothes washer	9.5	9.5	10.7	10.2	7.8	9.6	9.5	8.7	8.1
Front loading clothes washer	5.0	4.4	4.3	6.1	2.9	4.7	4.8	5.0	n/a
Electric clothes dryer	8.8	8.7	9.0	9.2	6.6	8.8	8.7	9.4	9.0
Gas clothes dryer	8.6	10.3	9.4	9.8	10.0	9.2	9.2	8.9	8.6

n/a = appliance not queried

8.4 Air Conditioning and Heating Appliances

Exhibit 8.10 presents the penetration and saturation rates for a range of space heating / cooling appliances. Of interest, air source heat pumps (ASHPs) are present in 4% of TGI households, up from just 1% in 1993. They are most popular among INT and TGVI customers (6% and 8% respectively). As ASHPs do function well during cold weather, they are typically paired with another space heating method. The most common pairings are either (i) forced air furnace as the main method with ASHP as secondary method, or (ii) ASHP as the main space heating method and a forced air furnace, gas fireplace, or electric baseboards as the secondary methods.

Terasen customers in the INT region are, by far, more likely to have central air conditioning (41%) compared to the other four TG regions (between 2% and 7%, depending upon the region). Ten percent (10%) of TG customers have a portable air conditioner, a relatively new entrant to the market for air conditioning. These units are particularly popular in the LM and FN regions (12% and 11% respectively).

Heat recovery ventilators were present in 2% of TG homes. Heat recovery ventilation systems allow homes to maintain high indoor air quality without excessive additional energy costs, as heat from the stale exhaust air is allowed to heat the incoming fresh outdoor air. Penetration is highest in the TGVI (5%) and TGW (7%) regions.

Exhibit 8.10: Air Conditioning and Heating Appliances

Heating / Cooling Appliance	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	574	728	566	208	137	2213	1439	1610	4814
Electric central air conditioner									
Penetration (%)	6.1	41.4	1.9	4.4	7.0	15.2	16.7	15.1	18.4
Saturation	0.06	0.42	0.02	0.04	0.07	0.15	0.17	0.16	0.19
Electric wall air conditioner									
Penetration (%)	11.3	8.7	7.5	15.8	5.6	10.3	10.5	9.1	4.0
Saturation	0.18	0.12	0.13	0.27	0.07	0.16	0.16	0.13	0.05
Portable air conditioner									
Penetration (%)	12.1	8.2	5.7	0.6	10.6	10.4	10.9	n/a	n/a
Saturation	0.15	0.09	0.06	0.01	0.12	0.12	0.13	n/a	n/a
Humidifier									
Penetration (%)	2.2	11.5	2.7	10.3	9.2	4.8	5.0	n/a	n/a
Saturation	0.02	0.12	0.03	0.11	0.09	0.05	0.05	n/a	n/a
Air source heat pump									
Penetration (%)	2.6	6.3	8.4	4.0	0.6	4.2	3.7	1.2	1.0
Saturation	0.03	0.06	0.09	0.06	0.01	0.04	0.04	0.01	0.01
Ground source heat pump									
Penetration (%)	0.2	0.5	0.3	--	--	0.3	0.2	1.1	n/a
Saturation [1]	0.0*	0.0*	0.0*	--	--	0.0*	0.0*	0.01	n/a
Gas outdoor heater (piped gas) [1]									
Penetration (%)	1.3	1.4	1.0	2.9	1.4	1.3	1.3	0.9	n/a
Saturation	0.02	0.01	0.01	0.03	0.01	0.02	0.02	0.01	n/a
Gas outdoor heater (bottled gas) [2]									
Penetration (%)	1.7	1.2	2.1	2.0	2.0	1.6	1.5	1.1	n/a
Saturation	0.02	0.01	0.02	0.03	0.02	0.02	0.02	0.01	n/a
Dehumidifier									
Penetration (%)	5.1	1.9	6.5	5.3	7.0	4.4	4.1	n/a	n/a
Saturation	0.05	0.02	0.07	0.06	0.07	0.05	0.05	n/a	n/a
Heat recovery ventilator									
Penetration (%)	1.9	0.7	4.9	6.8	2.8	1.9	1.6	1.8	n/a
Saturation	0.02	0.01	0.05	0.07	0.03	0.02	0.02	0.02	n/a

* Value smaller than 0.01
[1] Queried as natural gas outdoor heater in the 2002 REUS.
[2] Queried as propane outdoor heater in the 2002 REUS.
n/a = appliance not queried

Exhibit 8.11 provides the penetration and saturation rates for heating and cooling appliances by building type. Nineteen percent (19%) of customers in VSDs had an electric through-the-wall air conditioning unit, significantly more than those living in SFDs (10%) and MFDs (11%).

Exhibit 8.11: Air Conditioning and Heating Appliances by Building Type

Heating / Cooling Appliance	SFD	VSD	MFD	2008 TG
Unweighted base	1364	240	609	2213
Electric central air conditioner				
Penetration (%)	15.6	18.5	10.6	15.2
Saturation	0.16	0.19	0.11	0.15
Electric wall air conditioner				
Penetration (%)	10.2	18.7	10.8	10.3
Saturation	0.16	0.33	0.16	0.16
Portable air conditioner				
Penetration (%)	10.2	10.8	12.1	10.4
Saturation	0.12	0.12	0.16	0.12
Humidifier				
Penetration (%)	4.8	6.0	4.7	4.8
Saturation	0.05	0.08	0.05	0.05
Air source heat pump				
Penetration (%)	4.4	6.0	1.4	4.2
Saturation	0.05	0.07	0.02	0.04
Ground source heat pump				
Penetration (%)	0.2	1.9	1.5	0.3
Saturation	0.00	0.03	0.02	0.00
Gas outdoor heater (piped gas)				
Penetration (%)	1.3	1.0	0.8	1.3
Saturation	0.02	0.01	0.01	0.02
Gas outdoor heater (bottled gas)				
Penetration (%)	1.6	2.3	1.2	1.6
Saturation	0.02	0.03	0.01	0.02
Dehumidifier				
Penetration (%)	4.4	6.3	4.4	4.4
Saturation	0.05	0.07	0.05	0.05
Heat recovery ventilator				
Penetration (%)	2.0	2.5	0.7	1.9
Saturation	0.02	0.03	0.01	0.02

The average ages of heating and cooling appliances (first appliance) are provided in Exhibit 8.12.

Exhibit 8.12: Average Age (Years) of Air Conditioning and Heating Appliances (First Appliance)

Heating / Cooling Appliance	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Electric central air conditioner	8.7	10.8	11.0	7.0	10.3	10.2	10.2	10.1	n/a
Electric wall air conditioner	10.8	6.9	10.3	8.0	9.2	9.9	9.9	9.2	n/a
Portable air conditioner	3.2	5.5	4.1	3.0	2.3	3.7	3.7	n/a	n/a
Humidifier	4.8	7.6	7.7	8.6	3.7	6.8	6.7	8.0	n/a
Air source heat pump	2.6	4.4	6.3	7.6	--	4.4	3.7	8.4	n/a
Ground source heat pump	11.6	16.9	--	--	--	14.2	14.2	8.6	n/a
Gas outdoor heater (piped gas) [1]	6.4	16.3	3.3	7.5	8.0	8.7	9.2	4.4	n/a
Gas outdoor heater (bottled gas) [2]	5.4	1.2	2.7	2.8	3.0	4.0	4.2	2.1	n/a
Dehumidifier	5.4	8.1	5.3	12.2	8.4	5.8	5.9	n/a	n/a
Heat recovery ventilator	8.8	6.1	11.1	8.8	8.7	9.1	8.4	6.5	n/a

[1] Queried as natural gas outdoor heater in the 2002 REUS.
[2] Queried as propane outdoor heater in the 2002 REUS.
n/a = data not available

8.5 Energy Star® Appliances

Households were asked to indicate which of the following appliances they owned were Energy Star® qualified:

- Refrigerator
- Freezer
- Dishwasher
- Clothes washer
- Clothes dryer
- Air conditioner
- Dehumidifier

To address the concern that some respondents may not be aware of the Energy Star brand, the 2008 REUS survey provided a textual description of the Energy Star program, and provided visual examples of the Energy Star logo.

Exhibit 8.13 shows that the proportion of respondents' appliances rated Energy Star qualified varies from a low of 2% for air conditioners to a high of 53% for refrigerators. The relatively high incidence of Energy Star refrigerators and dishwashers was expected, as these appliances have been certified as Energy Star for some time.

Exhibit 8.13: Energy Star® Appliances (%)

Appliance	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	578	730	566	209	138	2221
Refrigerator	52.5	52.9	57.5	49.8	47.1	53.1
Freezer	18.8	27.2	28.9	15.8	27.8	22.1
Dishwasher	37.5	35.6	44.9	45.6	36.4	37.7
Clothes washer	34.8	38.3	43.0	34.4	45.7	36.6
Clothes dryer	7.1	15.6	3.8	2.0	6.4	9.0
Air conditioner	2.0	1.2	2.9	--	5.0	1.8
Dehumidifier	10.0	9.0	6.9	14.2	12.1	9.4

9 Pools & Hot Tubs

This section presents and discusses data collected from the 2008 REUS on swimming pools and hot tubs, including penetration and saturation rates, heating fuels, and operating behaviours. Detailed questions on swimming pools and hot tubs were directed only to customers whose swimming pool and/or hot tub was for their exclusive use only. Respondents who shared the swimming pool and/or hot tub with other residences, as is often the case in condominium complexes, were skipped past this section of the survey. Limiting questions on swimming pool and hot tub heating fuels and operating behaviours is a refinement of the 2002 survey methodology.

9.1 Penetration

Six percent (6%) of TG customers have access (exclusive or non-exclusive) to a swimming pool (Exhibit 9.1). The overall penetration of swimming pools (exclusive and non-exclusive) use for TGI customers, is unchanged from 2002 and 1993. Excluding responses from respondents whose pool was not for their exclusive use reduces the penetration of swimming pools among TG customers in 2008 to 5%. Pools are most common in the LM and INT regions, representing 5% and 6% of respondents respectively.

Exhibit 9.1: Penetration of Pools and Hot Tubs by Region (%)

	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	572	718	558	205	136	2189	1426	1610	4814
Swimming pool	6.9	6.8	2.4	3.4	1.4	6.3	6.8	6.6	5.2
Exclusive use of resident	5.3	6.2	2.1	1.9	1.4	5.2	5.6	n/a	n/a
Hot tub	13.5	17.9	11.5	41.2	8.8	14.5	14.8	10.8	8.2
Exclusive use of resident	12.1	16.9	10.7	37.1	7.8	13.3	13.5	n/a	n/a

n/a =data not available

The popularity of hot tubs has grown steadily since 1993 with 15% of TGI customers now having either an indoor or outdoor hot tub compared to 11% in 2002 and 8% in 1993. Removing hot tubs that are shared with other residences reduces the incidence of hot tubs from 15% to 13% for 2008 TG customers. Hot tubs are most common in the TW and INT regions (37% and 17% respectively).

Exhibit 9.2 summarizes the penetration data for pools and hot tubs by building type. Exclusive use of both pools and hot tubs is significantly lower for VSDs and MFDs compared to SFDs. Ninety-two percent (92%) of respondents in single family dwellings have exclusive use of their pool, versus only 12% and 6% of respondents in vertical subdivisions and multifamily dwellings, respectively. Similarly, hot tubs are significantly more likely to be shared with other residents in VSDs and MFDs.

Exhibit 9.2: Penetration of Pools and Hot Tubs by Building Type (%)

	SFD	VSD	MFD	2008 TG
Unweighted base [1]	63	36	33	132
Swimming pool				
Exclusive use	91.8	11.7	6.1	83.9
Shared with others	8.2	88.3	93.9	16.1
Hot tub				
Unweighted base [1]	230	40	66	336
Exclusive use	97.9	16.7	41.1	95.0
Shared with others	2.1	83.3	58.9	5.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

9.2 Pool Heating

Natural gas is the most common fuel used to heat swimming pools, used by 43% of TG customers with exclusive use pools (Exhibit 9.3). The next most commonly used fuels were solar (15%) and electricity (5%). Thirty six percent (36%) of pools are not heated.

Comparing fuel use data for TGI customers over the three survey years shows that the proportion using natural gas varies somewhat, although the small samples mean these differences are not statistically significant at the 95% confidence level.

Exhibit 9.3: Swimming Pool Fuel (%)

Exclusive use pools	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI [2]	1993 TGI [2]
Unweighted base [1]	19	29	9	4	2	63	50	98	238
Natural gas	47.6	35.7	37.0	49.2	50.0	43.4	43.6	56.0	49.1
Solar	5.8	32.1	25.9	--	--	15.0	14.6	20.7	14.2
Electric	5.8	0.0*	37.0	--	--	5.2	3.9	1.4	3.4
Propane	--	--	--	50.8	--	0.0*	--	--	--
Other	--	--	--	--	--	--	--	--	--
Not heated	40.8	32.1	--	--	50.0	36.4	37.9	24.1	26.8
DK/NR	--	--	--	--	--	--	--	2.6	5.8

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Includes multiple responses.
* Value less than 0.1%

Ten percent (10%) of respondents using either natural gas or electricity to heat their pools, used solar energy as a supplementary heating fuel. As a primary or secondary fuel, solar energy is used by 34% of all TG customers with exclusive use pools. Regional data on the use of solar energy for pool heating are not reported due to small sample sizes.

9.3 Hot Tub Heating

Electricity is the most common fuel used to heat hot tubs, used by 83% of TG customers with exclusive use hot tubs. Natural gas is a distant second, used by 15% of TG customers. Solar power is used by a small proportion of respondents (2%). Relative fuel shares for TGI customers suggest the shift away from natural gas between 1993 and 2002 appears to have reversed somewhat by 2008.

Exhibit 9.4: Hot Tub Fuel by Region (%)

Exclusive use hot tubs	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI [2]	1993 TGI [2]
Unweighted base [1]	45	86	50	77	11	269	142	185	374
Electric	76.3	91.9	97.6	83.1	100.0	83.4	82.2	86.3	74.7
Natural gas	21.1	8.1	2.4	4.0	--	15.0	16.2	13.1	21.8
Solar	2.6	--	--	--	--	1.5	1.6	0.7	0.3
Propane	--	--	--	12.9	--	0.1	--	0.5	0.4
Other	--	--	--	--	--	--	--	--	--
DK/NR	--	--	--	--	--	--	--	0.9	2.8

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Includes multiple responses

On average, exclusive use swimming pools are heated 3.7 months of the year (Exhibit 9.5). A small percentage (7%) of survey respondents heat their pools all year round.

Exhibit 9.5: Swimming Pools – Average Number of Months Heated
Heated Pools Only

Swimming Pools	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	12	20	8	4	1	45
Months heated (mean)	4.1	3.1	4.2	6.1	3.0	3.7
Heated all year (%)	12.2	0.1	0.0	25.7	0.0*	7.1

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
* value less than 0.1%

Hot tubs are heated for 8 months of the year, on average (Exhibit 9.6). Forty-two percent (42%) of TG customers heat their hot tubs year round.

Exhibit 9.6: Hot Tubs – Average Number of Months Heated

Hot Tubs	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base [1]	41	86	47	76	11	261
Months heated (mean)	7.5	9.0	8.8	9.8	7.4	8.2
Heated all year (%)	39.9	42.4	56.1	62.8	39.9	42.4

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Sixty-nine percent (69%) of TG customers with exclusive use heated pools use some form of pool cover when the pool is not in use (Exhibit 9.7). The use of a cover for hot tubs when not in use is almost universal (95%).

Exhibit 9.7: Use of Pool and Hot Tub Covers by Region (%)
Heated Pools and all Hot Tubs

	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base [1]	12	20	8	4	1	45	33	98	238
Cover pool when not in use	50.7	94.7	100.0	76.1	0.0	68.5	66.7	79.7	72.0
Unweighted base [1]	41	86	47	76	11	261	138	185	374
Cover hot tub when not in use	91.4	98.7	100.0	97.4	100.0	94.7	94.3	95.3	86.9

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

10 BEHAVIOURS

The 2008 REUS included a series of questions designed to understand how TG customers manage their household energy use, specifically those actions and behaviours that save energy.

There are many factors that can influence energy use in the home. This section of the report investigates differences in energy use behaviours by:

- TG region (LM, INT, TGVI, TGW, FN);
- building type (SFD, VSD, MFD);
- tenancy status (rent, own); and
- main space heating fuel (natural or piped propane gas, electric).

10.1 Heating Fuel Shares Revisited

To facilitate the investigation of these behaviours, it is useful to summarize the relative shares of the main heating fuels (electricity, natural or piped propane gas, and all others) by TG region (LM, INT, TGVI, TGW, and FN), building type (SFD, VSD, and MFD), and tenancy status (own, rent).

To facilitate the analyses, data on the relative shares of the main heating fuels by region, taken from Section 5, of the report are restated in Exhibit 10.1. Electric heat is the main heating fuel for 7% of TG customers, and ranges from 3% in the INT and FN regions, to highs of 26% in the TGVI region and 30% in the TGW region.

Exhibit 10.1: Main Heating Fuel by TG Region (%)

Main Heating Fuel	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	575	727	561	209	137	2209
Electric	5.5	2.9	26.3	29.5	2.9	6.9
Gas [1]	94.2	93.0	71.3	67.6	94.2	91.6
Other	0.3	4.1	2.4	2.9	2.9	1.5
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Includes piped natural gas and piped propane.

Exhibit 10.2 summarizes the heating fuel shares by building type and tenancy status. Electricity is the primary heating fuel for 7% of TG customers overall, but this proportion ranges from 6% for SFDs to 36% for VSDs. Differences between the proportions of customers with electric heat versus gas heat based on tenancy status are not statistically significant at the 95% confidence interval.

Exhibit 10.2: Main Heating Fuel by Building Type and Tenancy Status (%)

Main Heating Fuel	SFD	VSD	MFD	2008 TG	Tenancy Status	
					Own	Rent
Unweighted base	1362	241	606	2209	2073	127
Electric	6.3	35.6	12.9	6.9	6.9	8.7
Gas [1]	92.0	63.4	86.6	91.6	91.7	86.7
Other	1.6	1.0	0.5	1.5	1.4	4.6
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Includes piped natural gas and piped propane.

As the shares for heating fuels other than electricity and gas are small, they are excluded from subsequent tables in this section of the report.

10.2 Thermostats & Set-Back Behaviours

For most homes with the ability to control indoor temperatures with a thermostat, the ability to consistently reduce the temperature in the home at night or when no one is at home can be made easier by using a programmable thermostat. Exhibit 10.3 shows that 55% of TG customers have and use programmable thermostats. The presence of programmable thermostats is highest in the INT region (58%) and lowest in the FN region (48%).

Exhibit 10.3: Programmable Thermostats by Region (%)

Use one or more programmable thermostats?	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	571	716	556	208	137	2188
Yes	54.2	57.7	48.6	52.5	48.2	54.6
No	44.3	41.3	51.0	47.0	51.1	44.2
DK	1.5	1.0	0.3	0.5	0.7	1.2
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Exhibit 10.4 shows that SFDs are more likely to use programmable thermostats (55%) than VSDs (38%) and MFDs (48%). Programmable thermostats are also more likely to be used in dwellings that are owned, and that use gas as the main space heating fuel. Use of programmable thermostats did not vary by dwelling age (data not shown).

Exhibit 10.4: Programmable Thermostats by Building Type, Tenancy, & Main Heating Fuel (%)

Use one or more programmable thermostats?	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1353	232	603	2188	2054	124	1783	351
Yes	55.2	38.4	47.6	54.6	55.6	37.4	55.6	33.9
No	43.7	58.7	50.2	44.2	43.2	61.0	43.2	65.9
DK	1.1	2.9	2.2	1.2	1.2	1.7	1.3	0.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Natural gas or piped propane

Exhibit 10.5 summarizes the night-time temperature set-back behaviours in the five TG regions. Overall, 83% of TG customers always or usually set-back the temperature at night, with customers in the FN region significantly less likely to do so compared to the other regions. Customers in the INT and TGVI regions are significantly more likely than customers in other regions to consistently (always) reduce the temperature at night.

Exhibit 10.5: Night-time Temperature Set-Back Behaviours by Region (%)

Turn down temperature at night?	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	573	722	557	208	138	2198
Always	68.2	77.9	76.9	61.9	52.1	71.6
Usually	13.7	8.1	8.6	12.4	16.4	11.7
Occasionally	2.8	4.4	4.2	6.3	12.2	3.4
Never	15.3	9.1	9.5	18.9	18.6	13.0
Total	0.1	0.5	0.8	0.5	0.7	0.2
Always or usually	**81.9**	**86.0**	**85.4**	**74.3**	**68.5**	**83.3**

Totals may not sum due to rounding.

Exhibit 10.6 summarizes the set-back behaviours for when no one is in the home during the day. Overall, 70% of TG customers said they always or usually turn down the temperature during the day if none one is at home. Regionally, households in the FN region were significantly less likely to do so when compared to the other regions.

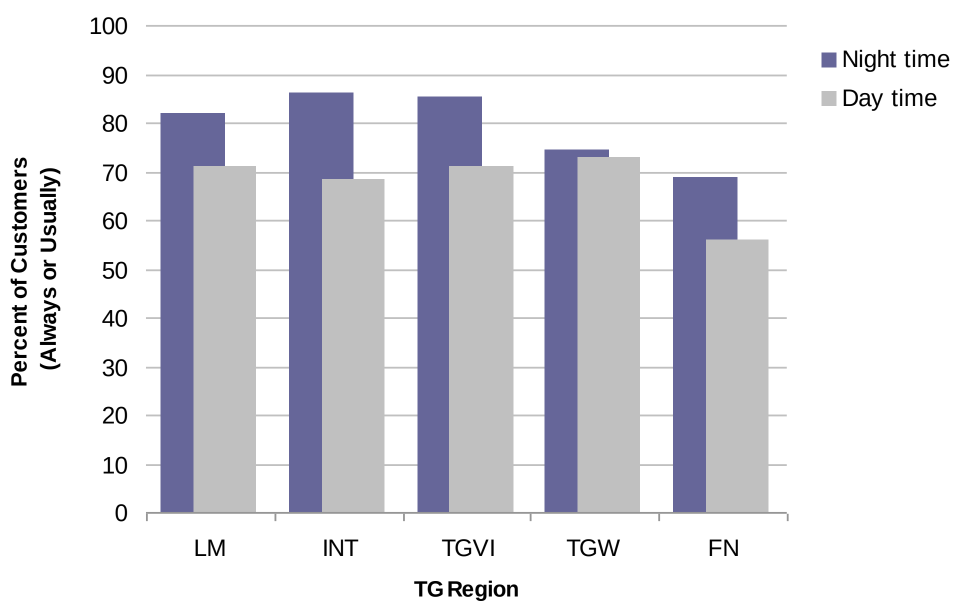
Exhibit 10.6: Day-time Temperature Set-Back Behaviours by Region (%)

Turn down temperature during day when no one at home?	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	572	720	556	207	138	2193
Always	48.2	46.8	49.3	46.2	35.7	47.9
Usually	22.6	21.6	21.8	26.6	20.0	22.3
Occasionally	14.9	16.8	12.7	14.0	19.3	15.2
Never	13.8	14.1	14.3	11.8	22.8	14.0
Total	0.4	0.7	1.9	1.4	2.1	0.6
Always or usually	**70.9**	**68.4**	**71.1**	**72.8**	**55.7**	**70.2**

Totals may not sum due to rounding.

Figure 10.1 graphically summarizes the night-time versus day-time set-back behaviours by the five TG regions. Customers in all regions, except TGW, are less likely to turn down the temperature during the day when no one it is at home compared to at night. Regionally, FN customers are significantly less likely to turn down the temperature during the day when the house is empty.

Figure 10.1: Temperature Set-Back Behaviours by Region



An analysis of setback behaviours for households with a programmable thermostat versus those without, indicates that homes with programmable thermostats are statistically more likely to always or usually turn down the temperature at night than those without (89.5% versus 75.5%) Differences in daytime setback behaviours for those with and without a programmable thermostat were not significantly different at the 95% confidence level (70.9% versus 69.9%).

Exhibit 10.7 summarizes the night-time and day-time set-back behaviours for the three building types, tenancy status, and main heating fuel. Only data for those who said they always or usually turned down their thermostats are reported. Thermostat set-back behaviours by building type show that VSD and MFD occupants have lower levels of both day and night set-back behaviours than SFDs. Set-back behaviours by owners and renters are also comparable, as are behaviours for natural gas heated customers and electric heated customers.

Exhibit 10.7: Set-back Behaviours by Building Type, Tenancy, & Main Heating Fuel (%)

	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1357	238	603	2198	2063	125	1792	350
Night-time (always, usually)	84.0	65.6	75.0	83.3	83.3	83.2	83.5	81.7
Day-time (always, usually)	70.5	65.7	66.5	70.2	71.2	70.0	70.2	71.1

Totals may not sum due to rounding.
[1] Natural gas or piped propane

Exhibit 10.8 summarizes the mean temperature (degrees Celsius) in the residence for when people are at home (occupied), at night, and when the residence is unoccupied during the day. Overall, TG customers keep their homes three degrees cooler during the night when someone is in the home. The mean temperature when no one is at home is effectively equal to the night-time set-back temperature (17 degrees).

To calculate the average temperature for the house, regardless of time of day, it was assumed that night-time set-back averages eight hours per day, and day-time set-back averages five hours per day. These data were then weighted by the share of people who responded that they “always” or “usually” performed the set-back behaviour. On average, the household temperature for TG customers is 19 degrees.

Exhibit 10.8: Thermostat Settings by Region (Degrees Celsius)

Thermostat Setting	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	552	702	538	203	135	2130
Occupied day-time temperature	20.2	20.5	20.2	19.8	20.5	20.3
Night-time temperature	17.3	17.2	16.3	16.5	18.2	17.2
Unoccupied temperature (day or night)	17.1	17.3	16.3	14.4	17.7	17.1
Average temperature	18.9	19.1	18.5	18.2	19.6	18.9

Totals may not sum due to rounding.

Mean temperatures by building type, occupancy status, and the two primary heating fuels are summarized in Exhibit 10.9. Differences are not statistically significant at the 95% confidence level.

Exhibit 10.9: Thermostat Settings by Building Type, Tenancy Status, & Main Heating Fuel (Degrees Celsius)

Thermostat Setting	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1317	231	582	2130	2000	121	1744	336
Occupied day-time temperature	20.3	20.2	20.3	20.3	20.3	19.7	20.3	20.0
Night-time temperature	17.2	17.8	16.9	17.2	17.2	16.3	17.3	16.1
Unoccupied temperature	17.1	16.7	16.9	17.1	17.1	16.7	17.2	15.7
Average Temperature	18.9	19.2	19.0	18.9	19.0	18.3	19.0	18.3

[1] Natural gas or piped propane

In addition to adjusting the temperature of the house, some homeowners can choose to heat only part of the home. This can be done closing off rooms, including closing down registers or turning off zoned electric baseboards. Exhibit 10.10 shows that 80% of TG customers have the ability to heat only part of their dwelling, and 65% always or usually keep these unoccupied areas cooler than other parts of the home. The proportion of customers that keep part of their home cooler (always or usually) is lowest in the FN region (48%) and highest in the TGW region (74%). The numbers for the FN region partially reflect the smaller proportion of customers that felt they could reduce temperatures in unoccupied parts of the home (73%).

The results for the TGW region are likely due to the part-time occupancy of dwellings in the resort community.

Defining the potential to reduce energy by turning off heat to parts of the home as the difference between the ability to reduce temperature and the proportion that said they already do so (either always or usually), the potential for further savings from this low cost / no cost behaviour is highest for FN and INT customers at 25% and 18% respectively, compared to an average of 15% across TG.

Exhibit 10.10: Partial Heating of the Residence, by Region (%)

	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	563	712	556	207	137	2175
Can reduce temperature in unoccupied parts of the home (A)	79.1	80.3	84.0	85.0	73.3	79.9
How often keep unoccupied areas cooler?						
Always	39.5	35.2	47.1	53.1	30.2	39.1
Usually	25.3	27.1	23.7	20.7	18.0	25.6
Occasionally	9.9	11.8	10.1	9.5	15.8	10.4
Never	21.5	23.8	16.9	12.1	33.1	21.7
DK	3.8	2.2	2.2	4.7	2.9	3.2
Always or usually (B)	64.8	62.2	70.8	73.7	48.2	64.7
Remaining potential (A - B) (%)	**14.3**	**18.1**	**13.2**	**11.3**	**25.1**	**15.2**

Totals may not sum due to rounding.

Exhibit 10.11 shows that significantly more electrically-heated than gas-heated residences always or usually keep part of the home cooler (77% versus 64%). The data show that the remaining potential to reduce energy use by encouraging this low cost / no cost behaviour is highest among SFDs and MFDs (15% and 14%, respectively), and homes that use gas as the primary space heating fuel (16%).

Exhibit 10.11: Partial Heating of the Residence, by Building Type, Tenancy, & Main Heating Fuel (%)

	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1339	234	602	2175	2041	124	1771	349
Can reduce temperature in unoccupied parts of the home (A)	80.3	71.4	74.9	79.9	80.2	73.2	79.6	83.9
How often keep unoccupied areas cooler?								
Always	39.0	49.9	39.8	39.1	39.5	31.4	37.6	53.8
Usually	26.0	16.0	21.1	25.6	25.2	28.8	25.9	23.4
Occasionally	10.4	6.7	10.7	10.4	10.6	7.8	11.0	4.9
Never	21.5	22.6	24.7	21.7	21.6	24.4	22.2	15.6
DK	3.2	4.8	3.6	3.2	3.1	7.6	3.3	2.2
Always or usually (B)	64.9	65.9	60.9	64.7	64.7	60.2	63.5	77.2
Remaining potential (A – B) (%)	**15.4**	**5.6**	**14.0**	**15.3**	**15.5**	**13.0**	**16.1**	**6.7**

Totals may not sum due to rounding.
[1] Natural gas or piped propane

Exhibit 10.12 provides additional detail on the potential to save energy by reducing the heat in unused rooms of the home. The exhibit summarizes the average number of rooms per dwelling, and heating practices. Room counts do not include bathrooms, closets or hallways. Overall, 79% of the rooms among TG customer homes are always heated. However, in the colder climates of the INT and FN regions, the shares are higher (84% and 89% respectively). The temperatures in unheated rooms in these regions would likely be colder than for comparable unheated rooms in the LM or TGVI regions. The exception is the

TGW region, where the share of rooms that are always heated is significantly lower than all other regions. This result likely reflects the higher proportion of part-time occupancy in the resort community.

Exhibit 10.12: Room Heating by Region

	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	566	708	552	207	135	2168
Dwelling size (ft^2)	2280	2149	2058	2186	1839	2220
Rooms always heated (#)	6.1	6.8	5.5	4.4	7.1	6.2
Rooms sometimes heated (#)	1.2	0.9	1.3	2.0	0.6	1.1
Rooms rarely / never heated (#)	0.6	0.4	0.7	0.5	0.3	0.6
Total rooms (#)	7.9	8.1	7.5	6.8	8.0	7.9
Share of rooms always heated (%)	77.2	84.0	73.3	64.7	88.8	78.5
Share of rooms sometimes heated (%)	15.2	11.1	17.3	29.4	7.5	13.9
Share rarely / never heated (%)	7.6	4.9	9.3	7.4	3.8	7.6
Total (%)	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Exhibit 10.13 summarizes room heating behaviour data by building type, tenancy status, and main heating fuel. Of note, customers living in VSDs and MFDs have a lower share of their rooms that are always heated than do those living in SFDs. As VSDs have fewer rooms and are smaller in overall square feet, this result is somewhat surprising. It may be attributed to the smaller footprint and open architecture design of VSDs which would allow the heat from the main room (e.g., living room) to maintain a comfortable temperature in other areas of the home. Also noteworthy, residents of electrically-heated dwellings heat significantly less of their house than do owners of natural gas heated houses (65% always heated versus 80%, respectively).

Exhibit 10.13: Room Heating by Building Type, Tenancy, & Heating Fuel

	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1336	234	598	2168	2038	124	1769	348
Dwelling size (ft^2)	2263	1291	1672	2220	2312	1196	2286	1800
Rooms always heated (#)	6.4	2.5	4.4	6.2	6.3	5.1	6.4	4.6
Rooms sometimes heated (#)	1.1	1.2	1.1	1.1	1.1	1.6	1.1	1.3
Rooms rarely / never heated (#)	0.6	0.7	0.6	0.6	0.6	0.4	0.5	1.2
Total rooms (#)	8.1	4.4	6.1	7.9	8.0	7.0	8.0	7.1
Share always heated (%)	79.0	56.8	72.1	78.5	78.8	72.9	80.0	64.8
Share sometimes heated (%)	13.6	27.3	18.0	13.9	13.8	22.9	13.8	18.3
Share rarely / never heated (%)	7.4	15.9	9.8	7.6	7.5	5.7	6.3	16.9
Total (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Natural gas or piped propane

10.3 Draft-Proofing

Routinely checking and refreshing draft-proofing (seals, caulking, etc.) is a relatively low cost way to reduce energy consumption in the home. The 2008 REUS asked a series of questions regarding draft-proofing, including how drafty the respondent's home is at present, how often draft-proofing activities are taken, and satisfaction with the draft-proofing results.

Exhibit 10.14 summarizes the current air tightness of TG customer homes by the five TG regions. Overall, 38% of customers said their home was somewhat drafty, and another 3% said it is always drafty. Regionally, FN customers were significantly more likely to say their homes were drafty compared to other regions (53% either somewhat or always drafty), followed by LM customers (44%). Homes in the TGVI and TGW regions were the least drafty (32% and 27% respectively).

Exhibit 10.14: Draftiness of the Home by Region (%)

Draftiness of the Home	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	562	720	556	206	138	2182
Always drafty	2.8	3.8	2.0	4.8	4.3	3.0
Somewhat drafty	41.2	32.6	29.8	22.8	48.6	37.7
Not at all drafty	46.1	58.0	62.5	67.0	42.1	51.0
DK	9.9	5.6	5.8	5.4	5.0	8.3
Total	100.0	100.0	100.0	100.0	100.0	100.0
Always or somewhat drafty	44.0	36.4	31.8	26.8	52.9	40.7

Totals may not sum due to rounding.

Customers living in VSDs, consistent with the relative newness of their structures, were significantly less likely to say their homes were either somewhat or always drafty (20%) compared to SFDs (41%) and MFDs (36%) (Exhibit 10.15). Renters were significantly more likely to say their home was either somewhat or always drafty (65%) compared to those who owned their homes (40%). Any differences between electrically-heated versus gas-heated homes were not statistically significant at the 95% confidence level.

Exhibit 10.15: Draftiness of the Home by Building Type, Tenancy, & Heating Fuel (%)

Draftiness of the Home	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1344	239	599	2182	2046	126	1777	350
Always drafty	3.0	4.4	2.9	3.0	2.4	15.5	2.9	4.3
Somewhat drafty	38.2	15.1	32.9	37.7	37.3	49.8	38.2	33.6
Not at all drafty	50.6	71.5	55.9	51.0	52.0	26.5	51.0	54.5
DK	8.3	9.0	8.3	8.3	8.3	8.1	7.9	7.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Always or somewhat drafty	41.2	19.5	35.8	40.7	39.7	65.3	42.1	37.9

Totals may not sum due to rounding.
[1] Natural gas or piped propane.

The data in Exhibit 10.16 suggest that TG customers are most likely to fall into one of two camps when it comes to the frequency of undertaking draft-proofing maintenance – those who do it once a year or more often (28%), and those who do it on an "as required" basis (36%). Sixteen percent (16%) said they never undertake draft-proofing.

Exhibit 10.16: Draft-Proofing Frequency by Region

Frequency of Draft-Proofing	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	570	718	560	208	138	2194
Once a year or more often	24.4	35.7	31.8	28.8	45.0	28.2
Once every two years	8.7	9.2	5.8	8.6	6.4	8.5
As required (> 2 years)	35.3	35.5	41.7	33.3	38.6	36.0
Never	19.0	11.1	13.8	20.7	7.9	16.3
DK	12.6	8.5	6.9	8.6	2.1	10.9
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Most likely due to the relative newness of their buildings and the use of third parties for building maintenance, residents of VSDs are significantly more likely to say they never or infrequently (more than every two years) check the draft-proofing of their residence (Exhibit 10.17). Owners are much more likely to do the weather stripping frequently (once a year or more) than are renters (29% versus 18%). There is no statistically significant difference between the frequency of weather stripping between customers with electric versus gas main space heat.

Exhibit 10.17: Draft-Proofing Frequency by Building Type, Tenancy, & Heating Fuel (%)

Frequency of Draft-Proofing	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1359	232	603	2194	2058	126	1790	349
Once a year or more often	28.7	17.2	22.6	28.2	28.6	17.7	28.2	29.3
Once every two years	8.7	7.3	6.2	8.5	8.9	2.2	8.5	7.5
As required (> 2 years)	36.2	20.6	34.0	36.0	36.2	29.7	36.2	37.3
Never	15.6	32.3	26.1	16.3	15.9	27.8	16.5	17.4
DK	10.8	22.6	11.0	10.9	10.4	22.5	10.7	8.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Natural gas or piped propane

When asked about the effectiveness of their draft-proofing, 25% of respondents said their homes were somewhat less drafty after draft-proofing, while another 26% said their efforts yielded no improvement (Exhibit 10.18). Of note, 27% of respondents did not know if the draft-proofing helped or not. By region, FN and INT customers had the best results (26% reporting much less drafty), and TGW customers had the poorest (19%).

Exhibit 10.18: Draft-Proofing Results by Region

Outcome of Draft-Proofing	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	531	670	538	204	135	2078
Much less drafty	20.9	25.7	21.9	18.7	26.3	22.3
Somewhat less drafty	24.6	25.0	22.7	18.0	30.6	24.5
No difference	24.6	28.8	27.8	29.9	30.0	26.1
DK	29.9	20.6	27.6	33.4	13.1	27.1
Total	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Exhibit 10.19 summarizes the outcome of customer's draft-proofing maintenance by building type, tenancy status, and the top two space heating fuels.

Exhibit 10.19: Draft-Proofing Results by Building Type, Tenancy, & Heating Fuel (%)

Outcome of Draft-Proofing	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1309	204	565	2078	1952	118	1688	337
Much less drafty	22.9	12.7	14.5	22.3	22.4	21.5	21.8	23.6
Somewhat less drafty	25.4	8.6	13.0	24.5	24.5	26.6	25.5	15.1
No difference	25.6	36.3	32.6	26.1	25.8	30.3	26.2	27.4
DK	26.2	42.5	39.9	27.1	27.3	21.6	26.5	33.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Natural gas or piped propane

Overall, there appears to be an opportunity for Terasen to provide information and training on effective draft-proofing techniques and materials to improve the results of homeowners' draft-proofing efforts.

10.4 Window Coverings

This section presents and discusses data on the use of storm windows, drapes, and other window coverings to reduce heat loss. Summary data on opening windows during the winter as a means to improve ventilation are also presented and discussed.

Exhibit 10.20 summarizes the percentage of respondents by TG region that install storm windows or plastic sheeting on single pane windows. Regionally, usage ranges from a low of 4% of TGW customers to a high of 33% of FN customers, with the overall TG average being 10%. The two most likely factors influencing the use of storm windows or plastic sheeting are the relative proportion of dwellings with one or more single pane windows, and climate. The incidence of single pane windows is generally greater than the proportion that reported using storm windows or plastic sheeting, with the exception of FN customers. The colder climate may mean that FN customers are using storm windows and/or plastic sheeting on double paned windows as well.

Exhibit 10.20: Storm Windows and Plastic Sheeting by Region (%)

	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	537	658	509	193	134	2031
Using storm windows or plastic sheeting	7.2	15.1	9.5	4.1	33.1	9.6
One or more single pane windows	33.1	17.2	26.3	6.1	15.3	28.0

Exhibit 10.21 presents the data on the incidence of single pane windows and the use of storm windows or plastic sheeting organized by building type, tenancy status, and main space heating fuel. Storm windows and/or plastic sheeting is used the least by customers living in VSDs, and the most by those in SFDs. Renters are significantly more likely than owners to use coverings on their windows (18% versus 9% respectively). Finally, gas-heated homes are more likely to use storm windows or plastic sheeting than electrically-heated homes (10% versus 5%). All data are consistent with the relative proportion of respondents indicating they have one or more single pane windows.

Exhibit 10.21: Storm Windows and Plastic Sheeting by Building Type, Tenancy, & Heating Fuel (%)

	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1249	204	540	1993	1869	120	1624	323
Using storm windows or plastic sheeting	9.9	1.5	5.8	9.6	9.1	17.8	9.9	5.1
One or more single pane windows	28.6	12.0	20.7	28.0	26.8	51.4	28.6	20.3

Totals may not sum due to rounding.
[1] Natural gas or piped propane.

Exhibit 10.22 summarizes the data on the use of window coverings such as drapes, blinds or shutters to reduce heat loss in winter. Sixty-nine percent (69%) of Terasen's customers always or usually cover their windows to reduce heat loss in winter. Use of window coverings is statistically equal for the LM, INT, and TGVI regions (69% to 70%), and significantly lower for TGW and FN regions.

Exhibit 10.22: Use of Window Coverings to Reduce Heat Loss in Winter by Region (%)

	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	571	719	559	207	136	2192
Always	46.2	41.1	39.4	37.1	36.2	44.1
Usually	22.7	28.5	29.4	21.2	27.5	24.9
Occasionally	19.7	15.8	15.2	22.8	17.4	18.2
Never	9.7	13.4	13.3	16.9	16.0	11.1
DK	0.7	0.7	0.8	1.0	0.7	0.7
Total	100.0	100.0	100.0	100.0	100.0	100.0
Always or usually	**68.9**	**69.6**	**68.8**	**58.3**	**63.7**	**69.0**

Totals may not sum due to rounding.

Inadequate air circulation in the home can cause people to open windows to gain access to fresh air, contributing to higher energy use. Data in Exhibit 10.23 show that TGVI and TGW customers are the most likely (always or usually) to open windows in winter to improve ventilation (34% and 31%, respectively). FN customers, with their significantly colder climate, are the least likely to open windows during the winter (3%). On average, 25% of TG customers report always or usually opening windows during the winter.

Exhibit 10.23: Open Windows in Winter to let in Fresh Air by Region (%)

	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	571	719	559	207	136	2192
Always	12.0	9.1	13.5	12.9	--	11.4
Usually	13.0	12.2	20.2	17.9	2.9	13.5
Occasionally	60.3	50.8	46.2	50.9	51.5	56.3
Never	13.7	27.6	19.2	18.3	45.7	18.1
DK	0.9	0.2	0.9	--	--	0.7
Total	100.0	100.0	100.0	100.0	100.0	100.0
Always or usually	**25.0**	**21.3**	**33.7**	**30.8**	**2.9**	**24.9**

Totals may not sum due to rounding.

Exhibit 10.24 summarizes window operations (covering, opening) by the three main building types, tenancy status, and main heating fuel. For brevity, only the proportions that indicate they always or usually exhibited the behaviour are reported. Of the three building types, customers in MFDs are less likely to use window coverings, and customers in VSDs more likely than SFDs to open windows during the winter. The latter effect may be due to more VSDs having centrally provided heating systems, or the multiple story / multiple unit structure of VSDs that lessens the demand on individual suite heating systems.

Exhibit 10.24: Window Operations by Building Type, Tenancy, & Heating Fuel (%)

Outcome of Draft-Proofing	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1352	235	605	2192	2056	126	1787	351
Use window coverings (always/usually)	69.2	68.8	58.3	69.0	68.6	77.9	69.7	63.0
Open windows (always/usually)	23.9	33.7	30.8	24.9	25.1	19.4	25.3	21.9

Totals may not sum due to rounding.
[1] Natural gas or piped propane

Proportionately more renters than owners use window coverings (78% versus 69%), and are less likely to open windows during the winter (19% versus 25%). The proportionately greater use of window coverings by renters is consistent with the relatively higher incidence of single pane windows among rental accommodations.[32]

10.5 Behaviours Affecting Hot Water Use

To understand the energy use and potential energy savings associated with hot water use in the home, respondents to the 2008 REUS were queried on a number of hot water using behaviours, including:

- number of dishwashing loads, laundry loads, baths, and showers per week;
- average length of showers;
- the tendency to limit shower length to save energy;
- share of laundry done in cold water – current and potential;
- check of hot water temperature; and
- hot water tank behaviours during vacation periods.

In cases where comparable questions on hot water use were queried in the 2002 and 2008 REUS surveys, the results for the two are compared and discussed. Unless otherwise noted, information regarding hot water behaviours is fuel neutral.

Respondents to the 2002 and 2008 surveys were asked to estimate how many dishwasher loads, laundry loads, baths, and showers occurred in their home in a typical week. Exhibit 10.25 summarizes the results of these questions by region and survey year. Of note, the average number of baths per week for TGI customers declined from 4.1 to 2.1 over the six year period, while the number of showers remained constant. Shower usage is highest for LM customers (average of 12.2 per week), and lowest for INT customers (9.4).

Exhibit 10.25: Hot Water Use Behaviours per Household by Region

Average per Household per Week	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	569	720	558	206	134	2187	1423	1610
Average # of people per home	3.1	2.4	2.4	3.0	2.7	2.8	2.8	3.0
Dishwasher loads	3.2	3.3	3.3	3.3	3.3	3.2	3.2	3.3
Laundry loads	4.7	4.5	4.2	3.8	5.3	4.6	4.6	5.2
Baths	2.1	2.4	2.5	1.6	2.9	2.2	2.1	4.1
Showers	12.2	9.4	9.8	11.3	10.3	11.2	11.4	11.5

Exhibit 10.26 explores the relationship between dishwasher loads, laundry loads, baths, and showers and the number of people in the home. The results show that much of the region-to-region variation in the average number of showers per week is explained by variations in the average number of people in the home. All other data, including the average number of laundry loads, dishwasher loads, and baths per person show some degree of regional variation. These variations are most likely related to regional differences in the relative proportion of young families versus seniors, and lifestyle differences. These latter characteristics were not explored.

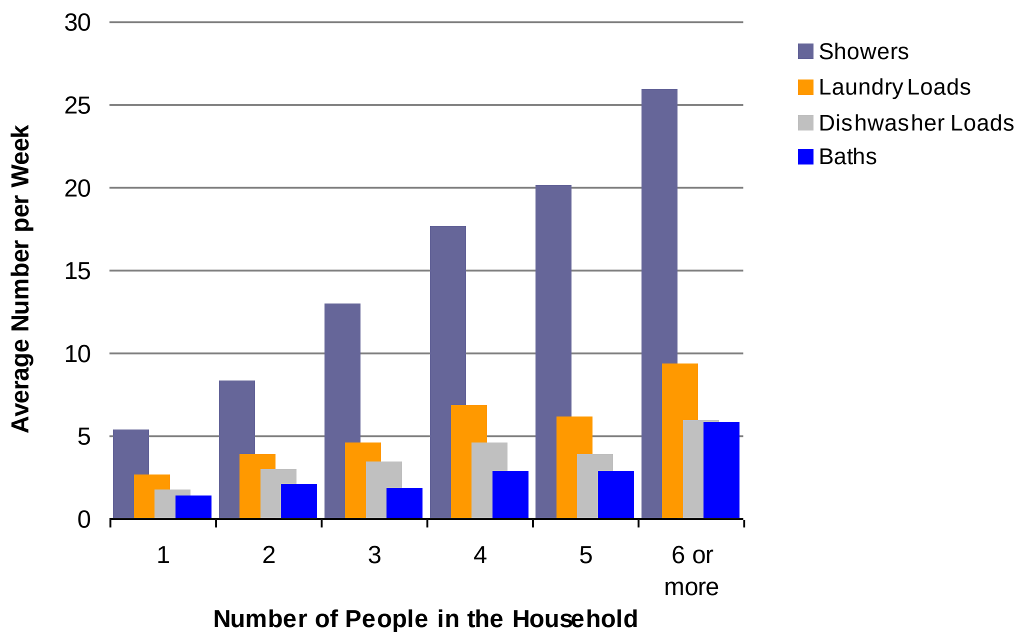
[32] Renters reported that 46% of their windows, on average, were single pane windows, compared to an average of 17% for owners.

Exhibit 10.26: Hot Water Use Behaviours per Person by Region

Average per Person per Week	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	569	720	558	206	134	2187	1423	1610
Average # of people per home	3.1	2.4	2.4	3.0	2.7	2.8	2.8	3.0
Dishwasher loads	1.0	1.4	1.4	1.1	1.2	1.1	1.1	1.1
Laundry loads	1.5	1.9	1.8	1.3	2.0	1.6	1.6	1.7
Baths	0.7	1.0	1.0	0.5	1.1	0.8	0.8	1.4
Showers	3.9	3.9	4.1	3.8	3.8	4.0	4.1	3.8

The relationship between the number of people in the household (household size) and water use for showering, bathing, dishwashing, and laundry is illustrated in Figure 10.2 . As the number of people in the household increases, so does the average number of water-using activities and behaviours per-household. Given these data, a household that decreases in size from four members to two (e.g., the typical situation when grown-up children leave home) will see, on average, a 36% decline in the number of dishwasher loads, a 43% decline in the number of laundry loads, a 30% decline in the number of baths, and a 53% drop in the number of showers. Everything else held constant, this would be expected to significantly reduce the demands for hot water heating.

Figure 10.2 Water Use Behaviours by Household Size



Hot water usage behaviours by building type, tenancy status, and main heating fuel are summarized in Exhibit 10.27. Of note, renters reported fewer weekly laundry loads (4.5) compared to owners (6.2), which may be the result of shared laundry facilities for renters, or the use of Laundromats.

Exhibit 10.27: Hot Water Use Behaviours by Building Type, Tenancy, & Heating Fuel (%)

Average Per Household per Week	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1353	235	599	2187	2054	124	1782	350
Average # of people per home	2.8	2.1	2.4	2.8	2.8	3.1	2.8	2.7
Dishwasher loads	3.2	3.3	3.2	3.2	2.7	3.3	3.3	3.2
Laundry loads	4.6	4.2	4.6	4.6	6.2	4.5	3.8	4.7
Baths	2.2	2.5	2.0	2.2	3.6	2.1	1.7	2.2
Showers	11.1	9.8	12.0	11.2	13.2	11.1	11.1	11.2

Totals may not sum due to rounding.
[1] Natural gas or piped propane

Exhibit 10.28 expresses the data from the previous exhibit on a per person basis. Of note, TG customers living in VSDs tend to run their dishwashers and laundry machines more, and take more baths and showers than those living in SFDs. The higher number of dishwasher and laundry loads may be due to the use of smaller "apartment size" appliances, or possibly the younger demographic that tends to populate VSDs (see Exhibit 12.2, p. 12-1). Also of note, renters tend to take fewer showers and baths, and do less laundry than homeowners. There are no differences between electrically-heated and gas-heated homes.

Exhibit 10.28: Hot Water Use Behaviours per Person by Building Type, Tenancy, & Heating Fuel (%)

Average per Person per Week	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1353	235	599	2187	2054	124	1782	350
Average # of people per home	2.8	2.1	2.4	2.8	2.8	3.1	2.8	2.7
Dishwasher loads	1.1	1.6	1.3	1.1	1.0	1.1	1.2	1.2
Laundry loads	1.6	2.0	1.9	1.6	2.2	1.5	1.4	1.7
Baths	0.8	1.2	0.8	0.8	1.3	0.7	0.6	0.8
Showers	4.0	4.7	5.0	4.0	4.7	3.6	4.0	4.1

Totals may not sum due to rounding.
[1] Natural gas or piped propane.

The length of a shower can greatly affect the amount of hot water used. REUS respondents were queried as to the total number of minutes that showers were in use during a typical weekday. The results are summarized in Exhibit 10.29 on a per household basis, and on a per household member basis. The latter was calculated by taking the total number of minutes of shower time for each household divided by the number of people in the household. Average shower use per household member is significantly higher in the LM, TGVI, and FN regions (between 8.3 and 8.5 minutes per shower), than in TGW (6.4 minutes).

Exhibit 10.29: Average Length of Shower (Minutes per Day) by Region

Shower Length (Minutes)	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	545	685	535	198	130	2093
All household members	23.5	16.4	17.8	17.4	19.3	21.0
Per household member	8.5	7.3	8.3	6.4	8.5	8.2
DK (%)	3.1	4.7	5.8	2.5	3.0	3.8

Exhibit 10.30 explores average per-person shower length (minutes) for residences with children (18 years or younger) to those without. While somewhat counterintuitive to parents with teenagers, the results suggest the average per-person shower length is higher for childless households.

Exhibit 10.30: Average Length of Shower (Minutes per Day) by Family Status

Shower Length per Person (Minutes)	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	545	685	535	198	130	2093
With children 18 years or younger at home	6.7	7.9	7.6	4.7	6.9	7.1
No children at home	9.2	7.1	8.5	7.2	9.7	8.6

The opportunity to save energy by reducing the average length of showers was explored by asking customers to state the degree to which they agree with the statement “members of my household regularly limit the length of their showers to save energy”. The degree of agreement ranged from one which meant “strongly agree” to five which meant “strongly disagree”. Those choosing to disagree are considered the most likely candidates for potential energy savings through a targeted behavioural change program. The findings, summarized in Exhibit 10.31, show that 78% of all TG customers either somewhat or strongly agreed that their family members regularly limit their showers to save energy. Conversely, only 6% either somewhat or strongly disagreed, and 17% were neutral (neither agree or disagree). The results suggest the best opportunity for behavioural based energy savings around shower usage rests with these latter two groups, equivalent to 22% of TG households.

Exhibit 10.31: Household Shower Limiting Behaviours by Region (%)

Members of my household regularly limit shower length to save energy.	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	545	685	535	198	130	2093
Strongly disagree (1)	3.0	1.9	1.2	1.0	1.5	2.5
Somewhat disagree (2)	3.0	4.0	3.2	2.9	3.6	3.3
Neither agree or disagree (3)	17.9	14.6	14.0	21.9	20.5	16.6
Somewhat agree (4)	30.5	36.5	35.0	29.6	35.0	32.6
Strongly agree (5)	45.7	43.0	46.7	44.7	39.4	45.0
Total	100.0	100.0	100.0	100.0	100.0	100.0
Disagree (1 or 2)	**6.0**	**5.9**	**4.4**	**3.9**	**5.1**	**5.8**
Agree (4 or 5)	**76.2**	**79.5**	**81.6**	**74.3**	**74.4**	**77.6**

Totals may not sum due to rounding.

The amount of laundry washed in cold rather than hot water can also significantly affect a home’s energy consumption. Exhibit 10.32 summarizes the share of laundry done in cold water, by region. Calculating an average based on the mid-point of the seven response categories yields an average of 58% of TG customers using cold water in their laundry machines. This average proportion did not vary significantly by region.

Exhibit 10.32: Share of Laundry Done in Cold Water by Region (%)

Share of Laundry Done with Cold Water	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	570	721	557	206	135	2189
0%	7.0	7.0	8.0	4.4	4.4	7.1
<20%	8.8	13.9	13.8	16.1	14.6	10.7
20% - 39%	17.1	11.5	9.2	11.6	11.0	14.8
40% - 59%	17.2	16.0	17.6	16.1	15.3	16.9
60% - 79%	10.0	13.2	12.6	12.5	11.7	11.2
80% - 99%	21.8	19.8	18.0	18.4	23.3	20.9
100%	13.6	15.9	18.9	16.4	19.0	14.8
DK	4.4	2.7	1.9	4.4	0.7	3.7
Total	100.0	100.0	100.0	100.0	100.0	100.0
Mean share (%)	**57.4**	**57.4**	**58.0**	**57.4**	**61.0**	**57.5**

Totals may not sum due to rounding.

The share of laundry done using cold water by building type, tenancy status, and main heating fuel, is summarized in Exhibit 10.33. The mean share (%) of laundry done in cold water does not vary significantly between building type, tenancy, or main heating fuel.

Exhibit 10.33: Share of Laundry Done in Cold Water by Building Type, Tenancy, & Heating Fuel (%)

Share of Laundry Done With Cold Water	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1350	238	601	2209	2055	125	1657	342
0%	7.0	8.0	8.0	7.1	7.0	9.4	7.2	7.4
<20%	10.6	12.7	11.4	10.7	10.5	15.1	10.4	15.0
20% - 39%	15.0	11.1	12.2	14.8	15.3	4.2	14.8	13.1
40% - 59%	16.9	13.3	17.1	16.9	16.8	16.9	16.9	19.0
60% - 79%	11.2	12.1	11.0	11.2	10.5	18.9	11.6	7.4
80% - 99%	21.0	21.6	18.2	20.9	21.4	12.3	20.6	23.4
100%	14.3	18.9	21.7	14.8	14.5	22.9	14.7	14.0
DK	4.0	2.3	0.4	3.7	3.9	0.3	3.8	0.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mean share (%)	**57.3**	**59.4**	**59.4**	**57.5**	**57.4**	**58.6**	**57.5**	**55.6**

Totals may not sum due to rounding.
[1] Natural gas or piped propane.

Exhibit 10.34 summarizes the estimated potential for energy savings from increasing the share of laundry done in cold water. On average, TG customers estimated they could increase their used of cold water in the wash / rinse cycle by an additional 5%. Of note, while 53% said they are doing all they can, 16% of Terasen customers felt they could do 20% or more cold water wash.

Exhibit 10.34: Cold Water Wash Potential by Region

Additional Cold Water Wash Potential	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	552	699	536	199	132	2118
None, already doing all I can	53.2	57.1	60.0	53.1	51.5	53.2
Less than 5%	9.8	10.8	10.2	12.5	13.4	9.8
Between 5% - 9%	8.2	5.8	6.0	5.5	11.9	8.2
Between 10% - 14%	10.4	11.8	6.9	7.1	5.2	10.4
Between 15% - 19%	2.9	2.4	3.3	3.6	1.5	2.9
20% or more	15.6	12.1	13.5	18.1	16.5	15.6
Total	100.0	100.0	100.0	100.0	100.0	100.0
Projected Mean Increase (%)	**5.7**	**4.9**	**4.8**	**5.8**	**5.3**	**5.4**

Totals may not sum due to rounding.

Exhibit 10.35 summarizes the potential for additional cold water wash and rinse by building type, tenancy status, and main heating fuel. Of note, 25% of renters said they could do 20% or more. This may reflect the tendency for renters to use common area washing machines or laundromats, where there is no financial incentive to use cold water in the wash / rinse cycle.

Exhibit 10.35: Cold Water Wash Potential by Building Type, Tenancy, and Heating Fuel (%)

Additional Cold Water Wash Potential	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1308	228	582	2118	1988	121	1608	331
None, already doing all I can	54.3	60.8	62.6	54.9	55.0	51.8	54.6	53.1
Less than 5%	10.3	4.1	7.0	10.1	10.2	8.4	10.3	8.8
Between 5% - 9%	7.3	7.0	7.5	7.3	7.4	7.5	7.1	12.0
Between 10% - 14%	10.7	8.9	6.9	10.4	10.5	6.6	10.8	6.9
Between 15% - 19%	2.8	4.6	3.0	2.8	2.9	0.4	2.6	4.4
20% or more	14.5	14.6	13.0	14.4	14.0	25.3	14.6	14.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Projected Mean Increase (%)	**5.4**	**5.4**	**4.6**	**5.4**	**5.3**	**6.7**	**5.4**	**5.6**

Totals may not sum due to rounding.
[1] Natural gas or piped propane

The potential for increasing the share of laundry done with cold water may be an opportunity for Terasen if a way can be found to address this niche market.

10.6 Hot Water Temperature

In addition to changing behaviours, the energy consumption associated with domestic hot water use can be reduced by turning down the temperature on the hot water tank. Exhibit 10.36 shows that 50% of TG customers have checked the temperature of the hot water in their home. Of those, 46% subsequently decreased the temperature of their hot water, 9% increased the temperature, and 46% left it unchanged. Regionally, the TGVI and INT regions stand out as having the highest percentage of customers that have checked their hot water's temperature (56% and 52% respectively).

Another energy saving behaviour is turning off the tank or using the tank's vacation setting (if present) when going away for more than two or three days. Thirty percent (30%) of TG customers reported turning off the hot water tank or using its vacation setting when away from the house for more than two to three days (Exhibit 10.36). This action is undertaken the least in FN (17%). This low proportion may be due to concerns that pipes may freeze if the tank is turned off during the winter. In contrast, the INT and TGVI regions have the highest participation rate for this behaviour.

Exhibit 10.36: Domestic Hot Water Temperature Behaviours by Region (%)

Hot Water Temperature Behaviours	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	571	722	558	208	138	2197
Checked temperature	47.2	52.3	56.2	45.7	48.5	49.5
Increased temperature	9.4	7.4	9.4	9.6	13.4	8.8
Decreased temperature	43.7	50.5	44.3	38.6	40.3	45.7
Left temperature unchanged	46.9	42.1	46.3	51.7	46.3	45.5
Turn down / off when away (Always or usually do so)	27.7	33.0	33.3	25.1	16.6	29.6

Totals may not sum due to rounding.

Exhibit 10.37 summarizes these data by the three building types, tenancy status, and main hot water heating fuel. VSDs are significantly less likely to check their hot water temperature (27% did so) compared to SFDs and MFDs (50% and 47%, respectively). This result is consistent with the lower penetration (54%) of in-suite hot water tanks in VSDs (Exhibit 7.2, p. 7-2). Temperature checking behaviour is somewhat less pronounced for customers with electrically-heated hot water tanks (45%), perhaps because the temperature is pre-set at the factory. Customers with electric tanks were also significantly more likely to have left the temperature of their hot water unchanged (66% for electric versus 43% for gas tanks).

Exhibit 10.37: Domestic Hot Water Temperature by Building Type, Tenancy, and Heating Fuel (%)

Hot Water Temperature Behaviours	SFD	VSD	MFD	2008 TG	Tenancy Status		Main Hot Water Heating Fuel	
					Own	Rent	Gas [1]	Electric
Unweighted base	1362	241	606	2209	2062	126	1663	346
Checked temperature of DHW	49.7	27.5	47.4	49.5	50.6	29.8	50.5	44.9
Increased temperature	8.5	10.8	13.2	8.8	8.9	4.6	9.7	0.4
Decreased temperature	46.1	40.4	40.5	45.7	46.6	17	47.4	34.0
Left temperature unchanged	45.4	48.8	46.3	45.5	44.5	79	42.9	65.6
Turn down / off DHW when away	29.5	21.2	31.5	29.6	29.9	21.2	31.2	20.2

Totals may not sum due to rounding.
[1] Natural gas or piped propane

11 PROGRAMS & SERVICES

This section summarizes the findings from a series of questions regarding past participation in energy efficiency programs, and interest in a series of programs and services that would help reduce energy use in the home. Additionally, this section summarizes a series of questions regarding attitudes, beliefs and behaviours regarding the environment and saving energy.

11.1 Past Participation in Programs to Reduce Energy Use

Respondents to the 2008 REUS were asked whether they had, in the last five years, participated in either a Terasen Gas, government or other program to reduce energy use in the home. The results, summarized in Exhibit 11.1, show that a relatively small percentage (11%) of TG customers have participated in an energy efficiency program during the past five years. Six percent (6%) indicated they participated in a Terasen program. A small percentage (0.3%) of customers are "super users" of energy efficiency programs, indicating they have participated in programs offered by Terasen, government, and others.

Exhibit 11.1: Participation in Programs to Reduce Energy by Region (%)

Past five years	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	560	691	545	203	133	2132
Terasen program	6.6	6.0	3.0	2.9	1.5	6.1
Government program	6.9	9.1	6.4	3.3	4.8	7.4
Other program	3.2	4.0	5.1	3.1	8.6	3.6
Any of the above	11.1	12.7	9.5	7.2	8.6	11.4
All of the above	0.3	0.2	0.0	0.0	0.7	0.3

Participation in a Terasen program during the past five years was significantly higher for LM and INT customers versus the three other regions.

Exhibit 11.2 summarizes past participation in energy efficiency programs by the three building types. Residents of VSDs are the least likely to have participated in an energy efficiency program during the past five years, regardless of sponsor (6%). This is likely due to the relatively young age of VSDs (e.g., energy using systems are newer and relatively efficient), and the tendency for space heating and/or water heating to be provided via centralized systems shared by all units in a VSD dwelling (i.e., less need and/or ability for individual participation in an energy efficiency program).

Exhibit 11.2: Participation in Programs to Reduce Energy by Building Type (%)

Past five years	SFD	VSD	MFD	2008 TG
Unweighted base	1315	229	588	2132
Terasen program	6.1	3.1	5.6	6.1
Government program	7.4	2.8	8.2	7.4
Other program	3.6	2.2	4.0	3.6
Any of the above	11.4	6.1	11.3	11.4
All of the above	0.3	0.0	0.0*	0.3

* value less than 0.1%

11.2 Interest in Products and Services

Respondents were asked to rate their interest in a series of products and services that would help reduce energy use in their residence. Interest was expressed using a four point scale, where one meant "not at all interested", to four which meant "very interested". The results, ordered by level of interest (i.e., the proportion scoring either a three or four on the four point scale), are summarized in Exhibit 11.3. The top three programs based on interest included furnace tune-up (56% either somewhat or very interested), home energy audit (50%), and do-it-yourself online energy audit (46%). A program to replace an electric clothes dryer with a gas dryer received the least interest (15%).

Exhibit 11.3: Interest in Products and Services (%)

Products and Services	Not at all interested (1)	(2)	(3)	Very interested (4)	Some-what or very interested (3 or 4)
Furnace tune-up to ensure that furnace is working safely and efficiently	28.6	15.4	26.3	29.7	56.0
Home energy audit to determine main energy uses in the home and identify opportunities to save energy	31.0	18.6	24.2	26.2	50.4
Do-it-yourself online energy audit	35.7	18.0	24.6	21.8	46.3
Program to improve draft-proofing	39.8	20.8	18.7	20.7	39.4
Program to replace water heater with high efficiency water heater	46.5	15.4	18.5	19.7	38.1
Program to replace furnace with high efficiency furnace	49.9	15.4	15.0	19.7	34.7
Program to replace clothes washer with high efficiency clothes washer	54.6	16.3	14.1	15.0	29.1
Program to upgrade ceiling and wall insulation	53.4	17.5	14.2	14.8	29.0
Program to replace dishwasher with high efficiency dishwasher	61.5	14.3	12.4	11.9	24.3
Program to replace gas fireplace with high efficiency gas fireplace	67.4	10.9	10.6	11.1	21.7
Program to install high efficiency gas fireplace	69.0	11.4	9.6	10.0	19.6
Program to replace electric range or cook top with gas range or cook top	67.4	13.1	9.0	10.5	19.5
Program to replace electric clothes dryer with gas dryer	70.5	14.3	8.2	7.0	15.2

11.3 Self-Assessed Knowledge of Ways to Save to Energy

Respondents were asked to rate their knowledge of ways to save energy using a four point scale ranging from "not at all knowledgeable" to "very knowledgeable". How respondents answered this question provides useful insight into potential barriers limiting the adoption of energy saving products and/or behaviours.

The data in Exhibit 11.4 show that 85% of TG customers felt they were either very or somewhat knowledgeable about ways to save energy. TGW customers were significantly most likely to say they were either very or somewhat knowledgeable (91%) versus LM and FN customers (84% each). The percentage of customers that felt they were the least knowledgeable (either not too knowledgeable or not at all knowledgeable) was highest in the LM and FN regions (16% each).

Exhibit 11.4: How Knowledgeable About Ways to Save Energy by Region (%)

Knowledge Level	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	569	715	551	206	136	2177
Very knowledgeable	12.8	12.1	15.3	14.4	12.3	12.9
Somewhat knowledgeable	71.1	73.6	75.2	75.4	71.7	72.2
Not too knowledgeable	16.2	14.0	9.2	10.2	16.0	14.9
Not at all knowledgeable	0.0*	0.2	0.3	--	--	0.1
Total	100.0	100.0	100.0	100.0	100.0	100.0
Very or somewhat knowledgeable	**83.9**	**85.7**	**90.5**	**89.8**	**84.0**	**85.1**
Not too or not at all knowledgeable	**16.2**	**14.0**	**9.5**	**10.2**	**16.0**	**15.0**

Totals may not sum due to rounding.
* Value less than 0.1%

Exhibit 11.5 summarizes self-assessed knowledge levels by the age of the survey respondent. No clear pattern or correlation between age and knowledge is apparent from the data. Respondents aged 55 to 64 years of age were the most likely to say they are very or somewhat knowledgeable (89%). Of note, 45 to 54 year olds (the next youngest cohort to 55 to 64 year olds) were the least likely to say they were knowledgeable (81%).

Exhibit 11.5: How Knowledgeable About Ways to Save Energy by Age Group (%)

Knowledge Level	24 yrs and younger	25 – 34 yrs	35 - 44 yrs	45 - 54 yrs	55 – 64 yrs	65 yrs and older	2008 TG
Unweighted base [1]	6	105	271	442	564	783	2171
Very knowledgeable	19.5	11.6	12.1	11.1	14.5	12.9	19.5
Somewhat knowledgeable	64.5	76.0	70.5	69.8	74.7	72.1	64.5
Not too knowledgeable	16.0	12.0	17.2	19.0	10.8	14.9	16.0
Not at all knowledgeable	--	0.4	0.1	0.0*	--	0.1	0.0*
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Very or somewhat knowledgeable	**84.0**	**87.6**	**82.7**	**80.9**	**89.2**	**85.0**	**84.0**
Not too or not at all knowledgeable	**16.0**	**12.4**	**17.3**	**19.0**	**10.8**	**15.0**	**16.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.
* Value less than 0.1%

Exhibit 11.6 summarizes the same self-assessed knowledge data by education level of the survey respondent. Of interest, respondents that were the least knowledgeable were either the least educated (some high school) or the most educated (post graduate). Based on these data, traditional education credentials do not appear to be a good indicator of energy saving knowledge.

Exhibit 11.6: How Knowledgeable About Ways to Save Energy by Education (%)

Knowledge Level	Some high school	Completed high school	Some trade / technical school	Completed trade / technical school	Some university / college	Completed university / college	Post graduate	2008 TG
Unweighted base	128	346	135	271	404	584	263	2131
Very knowledgeable	14.3	8.3	6.2	16.3	11.0	14.6	14.3	19.5
Somewhat knowledgeable	64.3	74.2	81.5	72.1	70.8	73.4	64.3	64.5
Not too knowledgeable	21.4	17.5	12.3	11.6	18.1	11.7	21.4	16.0
Not at all knowledgeable	--	0.1	--	--	0.0*	0.3	--	0.0*
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Very or somewhat knowledgeable	**78.6**	**82.4**	**87.7**	**88.4**	**81.9**	**88.0**	**78.6**	**84.0**
Not too or not at all knowledgeable	**21.4**	**17.6**	**12.3**	**11.6**	**18.1**	**12.0**	**21.4**	**16.0**

Totals may not sum due to rounding.
* Value less than 0.1%

11.4 Green Behaviours

TG customers were queried on frequency in which they undertook seven environmentally friendly (green) activities ranging from recycling to paying more for products that are environmentally friendly. Respondents rated their frequency of undertaking each activity using a four point scale ranging from "always" to "never" performing the activity. The results are summarized in Exhibit 11.7, ordered by the proportion of households that reported they always or usually undertook the behaviour.

The results highlight the relative acceptance of various behaviours. For example, 98% of respondents indicated they always or usually recycle newspaper, metals, plastic, or glass, while only 14% donate time or money to environmental causes. After recycling, the next most frequently undertaken behaviours include reducing energy use in the home (90%), using cloth /reusable grocery bags (67%), and purchasing environmentally friendly products (57%). While the results may be biased by the desire of some respondents to present themselves in a positive or environmentally friendly light, the data highlight that many behaviours have become engrained, at least in consciousness if not outright action.

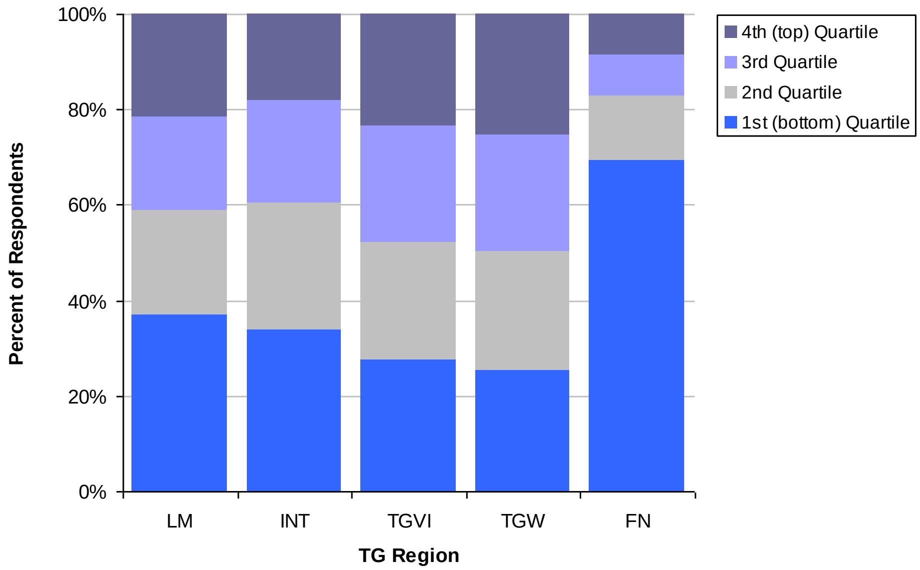
Exhibit 11.7: Frequency of Undertaking Environmentally Friendly Actions (%)

How often do you do the following?	Always	Usually	Occasionally	Never	Total	Always or Usually
Recycle newspaper, metals, plastics, or glass	89.6	8.8	1.2	0.4	100.0	**98.4**
Reduce energy use in the home	36.7	53.1	9.6	0.6	100.0	**89.8**
Use cloth / reusable grocery bags	31.3	35.7	23.4	9.6	100.0	**67.0**
Buy products that are environmentally friendly	13.1	43.9	41.5	1.5	100.0	**57.0**
Pay more for products that are environmentally friendly	7.6	30.2	48.3	13.9	100.0	**37.8**
Walk, ride a bike, carpool, or take public transit to help the environment	10.5	13.1	47.0	29.4	100.0	**23.6**
Donate time or money to environmental causes	4.6	9.2	46.5	39.7	100.0	**13.8**

Totals may not sum due to rounding.

Answers to the seven green behaviour questions were used to develop an overall “greenness” score for each REUS respondent. Those answering “never” to a question were scored a 0, “occasionally” a score of 1, “usually” a score of 2, and “always” scoring a 3. The scores for the seven questions were summed for each respondent. The maximum possible score per respondent was 21. Respondents were then grouped into one of four quartiles based on their overall score. Quartile 1 ranged from 0 to 10, quartile 2 ranged from 11 to 12, quartile 3, ranged from 13 to 14, and quartile 4 ranged from 15 to the maximum of 21. The results of this exercise are summarized by the five TG regions (Figure 11.1).

Figure 11.1: Frequency of Undertaking Environmentally Friendly Behaviours by Region



Of note, FN stands out as the region with the highest proportion of respondents in the bottom quartile. The remaining regions are relatively similar in the distribution by quartile, although TGVI and TGW have somewhat more households in the top two quartiles.

The relationship between the greenness scores and household income was also explored but there was no apparent correlation between income and the frequency of green behaviours (data not shown).

11.5 Attitudes Towards Energy

TG customers were asked to state their degree of agreement or disagreement to four statements regarding the characteristics of electricity and natural gas using a five point scale, where one meant “strongly disagree” and five meant “strongly disagree”. Exhibit 11.8 summarizes the responses to each of the four statements, with those who “agreed” (either a 4 or 5) and those who “disagreed” (either a 1 or 2) summarized in the right hand columns of the exhibit.

Exhibit 11.8: Attitudes Towards Energy (%)

Statement	Strongly Disagree (1)	(2)	Neither Agree or Disagree (3)	(4)	Strongly Agree (5)	Disagree (1 or 2)	Agree (4 or 5)
Natural gas is a clean and efficient energy source	2.5	3.3	16.6	32.6	45.0	5.8	77.6
Natural gas is a safe energy source	2.1	4.4	19.2	35.5	38.8	6.4	74.3
There is an adequate supply of domestically-produced electricity in BC	8.8	15.7	39.6	20.4	15.5	24.5	35.9
I have a good understanding of energy issues in BC	3.4	14.0	42.5	27.6	12.6	17.4	40.2

A total of 78% of TG customers agreed that natural gas is a clean and efficient energy source, within the margin of error of the 79% of TGI customers who agreed to the same statement in the 2002 REUS (not shown in exhibit). Thirty-six percent (36%) of TG customers agreed there is an adequate supply of domestically-produced electricity in British Columbia, while 25% disagreed, and 40% were neutral.

Only 36% of respondents agreed that British Columbia had an “adequate supply of domestically-produced electricity”, while 25% disagreed with the statement.

Forty percent (40%) of respondents felt they have a good understanding of energy issues in British Columbia, compared to 17% who did not.
Finally, 74% of respondents agreed with the statement “natural gas is a safe energy source”, while 6% disagreed.

Exhibit 11.9 provides a detailed regional breakdown of the results. Terasen’s INT customers were most likely to agree with 79% rating their agreement as either a 4 or 5, significantly higher than LM and TGVI customers at the 95% confidence level. Those who disagreed (either a 1 or 2) with the statement ranged from 3% (FN) to 7% (LM, TGVI, and TGW).

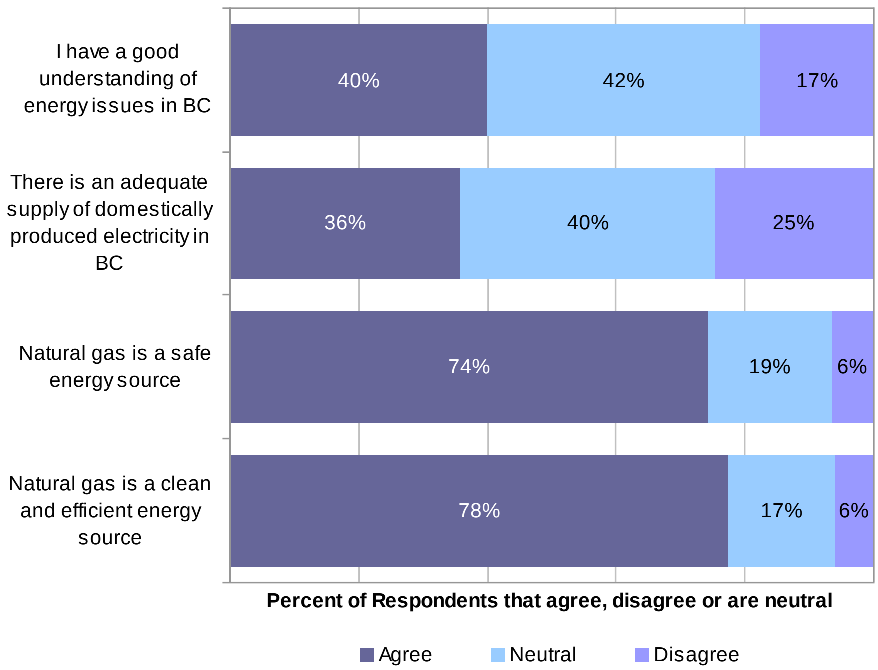
Exhibit 11.9: Attitudes Towards Energy – Natural Gas is a Safe Energy Source (%)

	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	564	698	542	205	135	2144
1 - Strongly Disagree	2.4	1.2	2.2	1.0	0.7	2.1
2	4.2	4.6	4.6	6.3	2.2	4.4
3 - Neither Agree or Disagree	20.9	15.1	19.9	20.5	25.6	19.2
4	34.9	37.3	34.5	36.1	34.3	35.5
5 – Strongly Agree	37.5	41.8	38.9	36.0	37.2	38.8
Total	100.0	100.0	100.0	100.0	100.0	100.0
Agree (4 or 5)	**72.5**	**79.1**	**73.3**	**72.2**	**71.5**	**74.3**
Disagree (1 or 2)	**6.6**	**5.8**	**6.8**	**7.3**	**2.9**	**6.4**

Totals may not sum due to rounding.

To facilitate comparison, these data are graphically illustrated in Figure 11.2.

Figure 11.2: Attitudes Towards Energy



12 Demographics

This section summarizes the key demographic and socio-demographic characteristics of respondents to the 2008 REUS, with comparisons, data permitting, to those who responded to the 2002 and 1993 surveys.

12.1 Age

Exhibit 12.1 summarizes the ages of respondents to the 2008 survey with comparisons to 2002. Respondent age was not queried in the 1993 REUS.

Exhibit 12.1: Age of Survey Respondents by Region (%)

Age Group	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	571	717	555	207	136	2186	1424	1491
18 yrs and younger	--	--	--	--	--	--	--	0.1
19 – 24 yrs	0.7	--	--	--	3.0	0.4	0.5	0.6
25 – 34 yrs	5.1	3.3	1.0	3.8	6.5	4.2	4.5	8.1
35 – 44 yrs	14.5	14.5	5.9	14.9	23.2	13.7	14.5	19.6
45 – 54 yrs	19.9	21.1	20.8	24.7	37.7	20.4	20.3	25.6
55 – 64 yrs	30.7	25.0	28.5	32.3	21.7	28.9	29.0	21.6
65 yrs and older	29.1	36.1	43.8	24.3	8.0	32.4	31.1	24.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Exhibit 12.2 summarizes respondent age by dwelling type. Of note, there is a relatively higher proportion of younger adults (34 years or less) living in VSDs than the other two building types.

Exhibit 12.2: Age of Survey Respondents by Building Type (%)

Age Group	SFD	VSD	MFD	2008 TG
Unweighted base	1348	237	601	2186
18 yrs and younger	--	--	--	--
19 – 24 yrs	0.4	0.7	0.5	0.4
25 – 34 yrs	3.8	15.3	9.1	4.2
35 – 44 yrs	13.5	17.4	16.1	13.7
45 – 54 yrs	20.7	17.1	15.8	20.4
55 – 64 yrs	29.5	19.3	21.1	28.9
65 yrs and older	32.0	30.2	37.3	32.4
Total	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

12.2 Marital Status

The marital status of respondents to the 2008 REUS is summarized in Exhibit 12.3. The proportion of respondents that were married or in a common law relationship is unchanged from 2002 at 80%.

Exhibit 12.3: Marital Status of Survey Respondents by Region (%)

Marital Status	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	566	713	552	207	136	2174	1415	1481
Single	6.4	7.7	5.7	11.5	15.3	6.7	6.8	6.8
Married / common law	80.8	78.0	77.5	78.0	69.5	79.7	79.9	79.9
Divorced / separated	5.6	5.5	7.7	9.1	11.6	5.8	5.6	7.3
Widowed	7.2	8.9	9.0	1.4	3.6	7.8	7.7	6.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
Marital status was not queried in the 1993 REUS.

Exhibit 12.4 shows that respondents living in SFDs are significantly more likely to be married or living common law than respondents living in VSDs and MFDs (81% versus 67% respectively). There is a higher incidence of single respondents in VSDs (17%) and a higher incidence of divorced / separated, or widowed respondents in MFDs (14% and 12% respectively). The proportions of married / common law and singles in Terasen's customer base differs from that of the 2006 Census data for British Columbia, reflecting the tendency for Terasen's customers to be older and to own their home.

Exhibit 12.4: Marital Status of Survey Respondents by Building Type (%)

Marital Status	SFD	VSD	MFD	2008 TG	2006 Census (BC) [1]
Unweighted base	1339	237	598	2174	3,433,880
Single	6.6	16.7	7.8	6.7	32.1
Married / common law	80.6	67.2	67.0	79.7	50.4
Divorced / separated	5.2	8.4	13.5	5.8	11.5
Widowed	7.5	7.7	11.8	7.8	6.0
Total	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Source: BC Stats 2006 Census Profiles. Population 15 years and older.

12.3 Number of People in the Household

Exhibit 12.5 summarizes the average number of persons living in the household by age group, and for the home overall. The average number of persons per household varies from a low of 2.4 persons for INT and TGVI region households to a high of 3.0 persons for TGW households. Examining the data by age group shows that the residents of TGVI and INT households are more likely to be older, and less likely to have children aged 18 years or younger in the home. Conversely, households in TGW and FN regions are younger, more likely to have children aged 18 years and younger at home, and less likely to have adults aged 65 years and older in the home.

Exhibit 12.5: Number of People in the Household by Age Group and Region

Age Group	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI
Unweighted base	571	713	553	208	136	2181	1401	1610	4814
18 yrs and younger	0.48	0.39	0.29	0.56	0.70	0.44	0.45	0.60	0.71
19 – 24 yrs	0.25	0.10	0.12	0.20	0.21	0.20	0.21	0.21	0.17
25 – 34 yrs	0.28	0.14	0.10	0.42	0.23	0.22	0.24	0.26	0.31
35 – 44 yrs	0.36	0.29	0.17	0.40	0.35	0.32	0.34	0.40	0.46
45 – 54 yrs	0.47	0.42	0.41	0.48	0.69	0.45	0.46	0.45	0.42
55 – 64 yrs	0.58	0.47	0.54	0.60	0.39	0.55	0.55	0.36	0.33
65 yrs and older	0.61	0.63	0.76	0.39	0.15	0.62	0.61	0.42	0.44
Household Mean	**3.01**	**2.43**	**2.39**	**3.04**	**2.70**	**2.79**	**2.83**	**2.97**	**2.84**
Household Standard Deviation	2.76	1.01	0.72	0.26	0.23	1.60	1.91	1.50	1.41

Exhibit 12.6 summarizes the average number of persons living in the household by age group, for each of the three building types. On average, VSDs have fewer people per household (2.1) versus MFD (2.4) and SFD (2.8). A review of the average number of individuals by age group shows that VSD households have the fewest individuals from most age groups with the exception of those aged between 25 and 44.

Exhibit 12.6: Number of People in the Household by Building Type

Age Group	SFD	VSD	MFD	2008 TG
Unweighted base	1346	236	599	2181
18 yrs and younger	0.44	0.17	0.45	0.44
19 – 24 yrs	0.21	0.07	0.09	0.20
25 – 34 yrs	0.23	0.28	0.19	0.22
35 – 44 yrs	0.32	0.36	0.34	0.32
45 – 54 yrs	0.46	0.29	0.31	0.45
55 – 64 yrs	0.56	0.33	0.37	0.55
65 yrs and older	0.62	0.56	0.63	0.62
Household Mean	**2.82**	**2.09**	**2.38**	**2.79**
Household Standard Deviation	1.98	0.29	0.63	1.60

Totals may not sum due to rounding.

As noted in Section 3.3.2, the number of occupants in the home can significantly impact energy use. To understand trends among Terasen's customer base, respondents were asked about changes to the number of people living in the household during the last two years. The data, summarized in Exhibit 12.7, show that 32% of TG customers saw a change in the size of their household during the last two years. TGVI customers had the least change (23% experienced a change in household size), whereas FN customers saw the most change (42%).

Eighteen percent (18%) of TG customers indicated there are fewer people living in the home than in the past (household size declining), compared to 7% who said there are now more (household size increasing), and another 7% that indicated the number of people has varied up and down. Taking the ratio of households that had declined in size to those that had increased shows that average household size has decreased for all regions, but less so for TGW and FN customers. For example, for every household in the LM that experienced an increase in the number of individuals living in the home, 2.6 households experienced a decline in household size.

Exhibit 12.7: Change in Number of People in the Household by Region (%)

	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	571	713	553	208	136	2181	1420	1610
Yes – changed in last two years	35.2	28.3	23.1	28.4	42.0	32.2	33.2	32.1
Yes – more people in the past	19.5	16.0	12.0	13.0	22.5	17.8	18.4	19.3
Yes – fewer people in the past	7.6	6.5	4.9	8.2	13.0	7.1	7.3	11.9
Yes – both fewer and more people in the past	7.8	5.7	6.2	7.2	6.5	7.1	7.2	4.6
Ratio of homes with more in the past to homes with fewer in past	2.6	2.5	2.5	1.6	1.7	2.5	2.5	1.6

Totals may not sum due to rounding.
Change in household size not queried in 1993 REUS

12.4 Education

Exhibit 12.8 summarizes the highest level of education achieved by survey respondents. The TGW region stands out for having a significantly higher proportion of customers that have completed university / college or have a post graduate degree. Data for TGI customers is provided for 2002. Education status was not queried in the 1993 REUS.

Exhibit 12.8: Highest Level of Education Completed by Region (%)

Education Level	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	578	730	566	209	138	2221	1446	1610
Some high school	3.3	7.5	5.7	1.4	10.8	4.7	4.6	9.2
Completed high school	17.2	15.5	19.2	6.7	20.0	16.9	16.7	14.4
Some trade / technical school	7.7	7.7	4.6	3.8	11.4	7.4	7.7	15.4
Completed trade / technical school	14.0	16.2	12.4	7.2	15.7	14.4	14.7	14.9
Some university / college	17.9	17.9	19.0	15.1	14.3	18.0	17.9	7.3
Completed university / college	26.9	23.6	24.8	38.8	21.4	25.8	25.9	23.7
Post graduate	10.7	7.2	10.8	26.0	4.3	9.8	9.6	6.1
NR	2.4	4.4	3.5	0.9	2.1	3.1	3.0	9.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.

Education levels for TG customers living in the building types are summarized in Exhibit 12.9. Of note, there is a significantly higher proportion of respondents living in VSDs with either a university / college degree or a post graduate degree versus respondents living in SFDs and MFDs. Data from the 2006 Census is provided for comparison purposes. Caution is advised as some of the education categories in the Census are defined differently in the 2008 REUS.

Exhibit 12.9: Highest Level of Education Completed by Building Type (%)

Education Level	SFD	VSD	MFD	2008 TG	2006 Census (BC) [1]
Unweighted base	1369	242	610	2221	2,856,950
Some high school	4.5	3.3	6.6	4.7	16.6
Completed high school	17.0	7.8	15.8	16.9	25.4
Some trade / technical school	7.5	1.5	6.2	7.4	12.2 [2]
Completed trade / technical school	14.8	10.6	9.9	14.4	
Some university / college	17.8	14.8	21.3	18.0	5.9
Completed university / college	25.8	38.9	25.5	25.8	31.7
Post graduate	9.6	20.7	11.3	9.8	8.2
NR	3.0	2.4	3.3	3.1	--
Total	100.0	100.0	100.0	100.0	100.0

[1] Source: BC Stats 2006 Census Profiles. Population 15 years and older.
[2] Includes those who completed a apprenticeship or trades certificate or diploma.
Totals may not sum due to rounding.

12.5 Household Income

Exhibit 12.10 summarizes annual household income before taxes of TG customers for the calendar year 2007. Consistent with the data on education, there are significantly more TGW customers with household incomes in excess of $125,000 compared to the other four regions. Also noteworthy is that the proportion of TGI customers with annual household incomes of less than $20,000 has declined from 13% in 1992 to 4% in 2008. Some of this decline may be due to general inflation in wages and salaries over the 1993-2008 period.

Exhibit 12.10: Annual Household Income by Region (%)

Annual Household Income	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI	1993 TGI	2006 Census (BC) [1]
Unweighted base	578	730	566	209	138	2221	1446	1610	4814	1,643,150
Less than $20,000	3.4	4.5	2.8	2.8	3.6	3.7	3.8	6.1	13.1	16.1
$20,000 to $39,999	16.2	17.6	17.9	2.8	7.1	16.7	16.6	17.2	21.0	21.4
$40,000 to $59,999	16.9	19.0	18.9	7.7	9.3	17.6	17.5	17.6	22.0	18.8
$60,000 to $79,999	15.1	16.2	12.4	9.1	15.7	15.1	15.5	14.9	13.9	14.8
$80,000 to $99,999	10.4	11.4	12.4	13.8	13.6	10.8	10.7	10.8	7.3	10.4
$100,000 to $124,999	12.5	9.9	8.7	9.1	21.4	11.5	11.8	6.7	6.0 [1]	18.7
Over $125,000	10.8	6.4	9.0	45.7	19.3	9.6	9.5	7.3		
NR	14.6	14.9	17.8	9.1	10.0	14.6	14.7	19.2	16.9	--
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] The maximum household income category used in the 1993 REUS was "over $100,000".
Totals may not sum due to rounding.

Household incomes by the three building types are summarized in Exhibit 12.11, and compared to data on household income (2005) from the 2006 Census. Consistent with the tendency for residents of VSDs to be better educated, there are proportionately more households in VSDs with household incomes of more than $100,000. Data from the 2006 Census shows a considerably higher proportion of households with less than $20,000 in annual household income. These are most likely renters and therefore, unlikely to be Terasen Gas customers.

Exhibit 12.11: Annual Household Income by Building Type (%)

Annual Household Income	SFD	VSD	MFD	2008 TG	2006 Census (BC) [1]
Unweighted base	1369	242	610	2221	1,643,150
Less than $20,000	3.6	3.9	4.5	3.7	16.1
$20,000 to $39,999	16.5	11.9	20.3	16.7	21.4
$40,000 to $59,999	17.7	16.7	15.9	17.6	18.8
$60,000 to $79,999	15.3	11.8	13.2	15.1	14.8
$80,000 to $99,999	10.8	12.7	11.0	10.8	10.4
$100,000 to $124,999	11.5	14.2	10.7	11.5	18.7
Over $125,000	9.6	15.2	9.4	9.6	
NR	15.0	13.7	15.0	3.7	--
Total	100.0	100.0	100.0	100.0	100.0

Totals may not sum due to rounding.
[1] Source: BC Stats 2006 Census Profiles. Income for 2005 tax year

12.6 Language

Exhibit 12.12 summarizes the main language spoken in the home by TG customers, with comparison of the TG totals to the 2006 Census data. English is the main language spoken in 89% of TG households. The proportion is significantly higher for regions outside the LM (between 96% and 98% depending upon the region). Cantonese is the next most commonly spoken language (4% of TG customers), followed by Mandarin (1%). When taken together, the three Chinese languages (Cantonese, Mandarin, and Other) account for 5.4% of TG customers.

Exhibit 12.12: Main Language Spoken in the Home (%)

Language	LM	INT	TGVI	TGW	FN	2008 TG	2006 Census (BC) [1]
Unweighted base	578	730	566	209	138	2221	4,074,385
English	88.8	97.6	96.8	97.6	96.4	88.8	83.6
Mandarin	1.4	0.0*	0.3	--	--	1.4	
Cantonese	3.6	--	0.3	0.5	--	3.6	6.7 [2]
Other Chinese	0.4	--	--	--	--	0.4	
Punjabi	0.4	--	--	--	0.7	0.4	3.0
Korean	0.0*	--	--	--	--	0.0*	1.0
Tagalog	1.0	--	--	--	--	1.0	0.6
Farsi (Persian)	--	--	--	--	--	--	0.5
Vietnamese	--	0.2	--	--	--	0.0*	0.5
Spanish	0.1	--	--	--	0.7	0.1	0.4
French	0.4	0.2	--	--	--	0.4	0.4
German	0.6	0.7	0.3	--	--	0.6	0.3
Hindi	0.3	--	--	--	--	0.3	0.3
Other	1.6	--	0.5	0.9	0.7	1.6	2.8
NR	1.4	1.2	1.9	1.0	1.4	1.4	--
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

* Value less than 0.1%
[1] Source: BC Stats
[2] Not differentiated in the 2006 Census
Totals may not sum due to rounding.

Compared to the 2006 Census data, a somewhat larger proportion of TG customers speak English (89% versus 84%). The distribution of languages, other than English, spoken in the home generally compares favourably with Census data.

Recognizing that more than one language may be spoken in the home, TG customers were asked to identify all other languages spoken. The results are summarized in Exhibit 12.13.

Exhibit 12.13: All Other Languages Spoken in the Home (%)
Multiple Responses Allowed

Language	LM	INT	TGVI	TGW	FN	2008 TG
Unweighted base	578	730	566	209	138	2221
French	4.5	3.4	6.1	11.1	1.4	4.3
English	5.5	0.9	0.3	1.4	--	3.7
German	2.5	2.6	1.4	2.4	--	2.4
Cantonese	2.1	--	0.8	1.4	--	1.4
Spanish	1.7	0.5	0.8	1.9	--	1.3
Mandarin	1.0	--	0.5	1.0	--	0.7
Punjabi	0.9	0.2	0.3	--	0.7	0.7
Tagalog	0.8	0.3	--	1.0	0.7	0.6
Hindi	0.7	0.2	0.3	--	--	0.5
Other Chinese	0.6	--	0.3	0.5	--	0.4
Vietnamese	0.3	0.2	--	--	--	0.3
Japanese	0.3	0.0*	0.3	0.5	--	0.2
Korean	0.0*	0.0*	--	--	--	0.0*
Farsi (Persian)	0.0*	--	0.3	0.5	--	0.0*
Other	3.8	1.5	1.6	1.9	2.1	2.9

* Value less than 0.1%
Totals may exceed 100% as multiple responses were allowed

13 CONDITIONAL DEMAND ANALYSIS

Information on end use energy consumption is used for power system planning, load forecasting, marketing and demand side management. End use consumption refers to the consumption of space heating, water heating, cooking and other specific uses as opposed to total consumption. The Unit Energy Consumption (UEC) for an end use is defined as the quantity of energy consumed by that end use in a given period of time. The purpose of this section is to present the results of a conditional demand analysis (CDA) performed using respondents' survey data from the 2008 REUS matched with weather data and billing consumption data.

The objectives of the conditional demand analysis were to:

- estimate weather-normalized UEC values for residential end uses, including:
  - primary space heating
  - secondary space heating
  - water heating
  - decorative fireplace
  - heater type fireplace
  - gas range, cook top & oven
  - gas dryer
  - swimming pool
  - piped gas barbeque
  - hot tub
- estimate UEC values for each of the five TG regions (LM, INT, TGVI, TGW, FN)
- weighted UEC estimates for TG and TGI
- disaggregate UECs for key end uses for three building types (SFD, VSD, MFD)

A detailed presentation of the methodology, equation specifications, and equation results for the CDA are included in Appendix B.

13.1 CDA Sample

The sample used for the CDA was drawn from the participants in the 2008 REUS survey that had two years of uninterrupted monthly / bimonthly billing history (July 2006 to July 2007). Filtering out respondents with incomplete or irregular billing data reduced the available sample for the CDA from the original 2,221 REUS respondents to 2077 respondents. Exhibit 13.1 summarizes the sample used for the CDA analysis. Billing data and monthly weather data (heating degree days and hours of sunlight) were provided by Terasen.

Exhibit 13.1: Sample used in the Conditional Demand Analysis – 2008 REUS

Dwelling Type	LM	INT	TGVI	TGW	FN	TG
SFD	294	435	370	93	137	1329
VSD	114	62	4	-	-	180
MFD	170	173	190	34	1	568
Total	578	670	564	127	138	2077

13.2 UEC Estimates – TG and TGI Weighted Averages

The conditional demand model was estimated using ordinary least squares (OLS) regression. Overall, the model performed well. Most regression coefficients had the correct sign and were significant at the five percent level or better (see Appendix B). The value of the adjusted R-squared value was 0.864 and the F statistic was 8,236.

The regression coefficients were used to calculate Unit Energy Consumption (UEC) values for major residential end uses. UECs were calculated for each household possessing the end use by substituting household variables into the end use equations. Normal heating degree days and hours of sunlight were substituted to generate weather-normalized UECs for space heating and water heating. Weighted average UECs for the TG and TGI business divisions were then calculated across all households possessing the end use and across the various household subgroups.

13.2.1 TG Weighted Average

The weighted average UEC estimates for TG are shown in Exhibit 13.2. As expected, the largest end uses are primary space heating at 57.8 GJ per year and secondary space heating at 23.2 GJ per year. Other major end uses are water heating (19.8 GJ per year), decorative fireplaces (20.9 GJ per year) and heater type fireplaces (17.4 GJ per year). Pools and hot tubs are also heavy users of natural gas, but they have lower penetration rates than other major end uses.

Exhibit 13.2: Unit Energy Consumption Estimates – TG

End Use	Sample Size (unweighted)	Penetration (% presence)	2008 UEC Estimate (GJ/year)	Average Consump-tion per Household (GJ/year)	Average Consump-tion per Household (%)	2002 UEC Estimate (GJ/year)
Primary Space Heating	1,720	91%	57.8	52.6	61%	67.8
Secondary Space Heating	268	7%	23.2	1.5	2%	n/a
Water Heating	1,624	84%	19.8	16.6	19%	20.8
Decorative Fireplace	354	18%	20.9	3.8	4%	16.8 [1]
Heater Fireplace	932	42%	17.4	7.3	8%	15.8 [2]
Range, Cook Top, Oven	550	23%	5.4	1.3	1%	8.5
Barbeque	402	15%	8.1	1.2	1%	3.1
Dryer	148	6%	3.9	0.2	<1%	4.0
Pool	28	2%	38.5*	0.9*	1%	53.5
Hot Tub	31	2%	19.5	0.4	<1%	17.9
Household Consumption						
Estimated				**85.8**		**96.1**
Actual				**98.9**		**104.9**

* Small sample size (less than 30 households with end use present).
[1] 2002 data represents log fireplaces.
[2] 2002 data represents inserts.

The average gas consumption per household (HEC) is calculated by multiplying each end use UEC by its penetration rate and summing across end uses. The HEC is a measure of the average consumption of a household in Terasen's service territory. The weather-normalized weighted HEC for TG was estimated to be 85.8 GJ per year. In comparison, the actual weighted average consumption for the sample was 98.9 GJ per year. The estimate of weather-normalized consumption is lower than actual consumption, in part because weather conditions during the CDA analysis period were colder than average. There is also a tendency for conditional demand analyses to underestimate total household consumption.[33]

Exhibit 13.2 also provides a comparison with the UEC estimates from the conditional demand analysis conducted in 2002.[34] The most significant change observed is the drop in primary space heating gas consumption. This is partly explained by improvements in heating efficiency over the time period. Some of this decline may also be due to methodological differences between the two CDA studies. Notably, the 2002 CDA did not address regional differences in its model formation. This appears to have led to an over-estimation of the space heating UEC for the INT region. Also, consistent with the 2002 REUS, the

[33] Conditional demand models force the intercept term to zero (i.e., no intercept) to prevent it from capturing part of the effect that should be allocated to individual end uses. This treatment of the intercept, however, can result in an underestimate of total household consumption because non-modelled end uses (e.g. patio heaters) and behaviours (e.g. heating use in the summer) are not captured.

[34] Habart 2003

2002 CDA model did not have TGVI and TGW customers in its sample. TGVI now forms a sizable portion of Terasen's service territory, but has lower space heating consumption than either of the LM or INT regions.

The UECs for many of the other end uses are relatively consistent between the two CDAs, with the exception of some of the lower penetration end uses. Of note, the UEC for barbeques appears to be over-estimated in the current study. This may be due to small sample sizes or a confounding effect with other end uses (e.g., gas ranges). A review of other studies suggests UEC estimates for barbeques should be about 2 to 3 GJ/year.

13.2.2 TGI Weighted Average

Exhibit 13.3 shows the weighted average UEC estimates for TGI. Comparisons with 2002 show similar trends to that found with the TG weighted averages.

Exhibit 13.3: Unit Energy Consumption Estimates – TGI

End Use	Sample Size (unweighted)	Penetration (% presence)	2008 UEC Estimate (GJ/year)	Average Consump-tion per Household (GJ/year)	Average Consump-tion per Household (%)	2002 UEC Estimate (GJ/year)
Primary Space Heating	1,242	93%	59.0	55.1	63%	67.8
Secondary Space Heating	101	5%	24.7	1.2	1%	n/a
Water Heating	1,116	84%	19.9	16.8	19%	20.8
Decorative Fireplace	246	19%	20.9	3.9	4%	16.8 [1]
Heater Fireplace	546	40%	17.7	7.1	8%	15.8 [2]
Range, Cook Top, Oven	321	23%	5.5	1.2	1%	8.5
Barbeque	207	14%	8.1	1.2	1%	3.1
Dryer	71	5%	4.0	0.2	<1%	4.0
Pool	21	2%	38.5*	0.9*	1%	53.5
Hot Tub	19	2%	19.5*	0.4*	<1%	17.9
Household Consumption						
Estimated				**88.8**		**96.1**
Actual				**102.3**		**104.9**

* Small sample size (less than 30 households with end use present).
[1] 2002 data represents log fireplaces.
[2] 2002 data represents fireplace inserts.

13.3 UEC Estimates by Region

Regional terms were incorporated into the CDA model for space heating to develop UEC estimates by the five TG regions.

13.3.1 Lower Mainland

Exhibit 13.4 shows weighted average UECs for the Lower Mainland region. The weather-normalized, weighted average annual energy consumption per household (HEC) was estimated to be 92.1 GJ per year. In comparison, the actual weighted average consumption for the sample was 108.9 GJ per year.

Exhibit 13.4: Unit Energy Consumption Estimates – Lower Mainland

End Use	Sample Size (unweighted)	Penetration (% presence)	2008 UEC Estimate (GJ/year)	Average Consump-tion per Household (GJ/year)	Average Consump-tion per Household (%)	2002 UEC Estimate (GJ/year)
Primary Space Heating	494	94%	62.0	58.0	63%	65.3
Secondary Space Heating	62	5%	18.1	0.9	1%	-
Water Heating	426	84%	20.4	17.2	19%	21.0
Decorative Fireplace	129	20%	21.4	4.2	5%	16.2 [1]
Heater Fireplace	274	42%	18.3	7.8	8%	14.9 [2]
Range, Cook Top, Oven	196	26%	5.6	1.4	2%	8.6
Barbeque	66	12%	8.1	1.0	1%	3.4
Dryer	24	5%	4.2*	0.2*	<1%	4.0
Pool	10	3%	38.5*	1.0*	1%	53.6
Hot Tub	11	3%	19.5*	0.5*	<1%	17.8
Household Consumption						
Estimated				**92.1**		**93.8**
Actual				**108.9**		**109.0**

* Small sample size (less than 30 households with end use present).
[1] 2002 data represents log fireplaces.
[2] 2002 data represents fireplace inserts.

13.3.2 Interior

Exhibit 13.5 shows weighted average UECs for the Interior region. The weather-normalized, weighted average annual energy consumption per household (HEC) was estimated to be 78.5 GJ per year. In comparison, the actual weighted average consumption for the sample was 86.7 GJ per year.

Exhibit 13.5: Unit Energy Consumption Estimates – Interior

End Use	Sample Size (unweighted)	Penetration (% presence)	2008 UEC Estimate (GJ/year)	Average Consump-tion per Household (GJ/year)	Average Consump-tion per Household (%)	2002 UEC Estimate (GJ/year)
Primary Space Heating	617	93%	51.6	48.0	61%	74.1
Secondary Space Heating	37	5%	39.3	2.0	3%	-
Water Heating	574	86%	18.8	16.0	20%	20.3
Decorative Fireplace	111	16%	19.8	3.2	4%	18.6 [1]
Heater Fireplace	251	35%	15.9	5.5	7%	18.3 [2]
Range, Cook Top, Oven	96	16%	5.1	0.8	1%	7.8
Barbeque	124	20%	8.1	1.6	2%	2.8
Dryer	35	6%	3.6	0.2	<1%	4.0
Pool	10	2%	38.5*	0.9*	1%	53.3
Hot Tub	8	1%	19.5*	0.3*	<1%	17.9
Household Consumption						
Estimated				**78.5**		**101.7**
Actual				**86.7**		**96.7**

* Small sample size (less than 30 households with end use present).
[1] 2002 data represents log fireplaces.
[2] 2002 data represents inserts.

Of note, the 2002 CDA overestimated energy consumption per household, with the most likely source of the overestimate being the primary space heating UEC estimate.

13.3.3 Vancouver Island

Exhibit 13.6 shows weighted average UECs for the Vancouver Island region. The weather-normalized weighted average annual energy consumption per household (HEC) was estimated to be 64.8 GJ per year. In comparison, the actual weighted average consumption for the sample was 67.2 GJ per year.

Exhibit 13.6: Unit Energy Consumption Estimates – Vancouver Island

End Use	Sample Size (unweighted)	Penetration (% presence)	2008 UEC Estimate (GJ/year)	Average Consump-tion per Household (GJ/year)	Average Consump-tion per Household (%)
Primary Space Heating	377	71%	43.0	30.4	47%
Secondary Space Heating	149	23%	19.9	4.5	7%
Water Heating	420	76%	18.8	14.4	22%
Decorative Fireplace	72	12%	19.7	2.5	4%
Heater Fireplace	337	56%	16.1	9.1	14%
Range, Cook Top, Oven	162	28%	4.7	1.3	2%
Barbeque	136	24%	8.1	1.9	3%
Dryer	67	13%	3.4	0.5	1%
Pool	3	1%	38.5*	0.3*	<1%
Hot Tub	1	0%	19.5*	0.1*	<1%
Household Consumption					
Estimated				**64.8**	
Actual				**67.2**	

* Small sample size (less than 30 households with end use present).

13.3.4 Whistler

Exhibit 13.7 shows weighted average UECs for the Whistler region. The weather-normalized, weighted average annual energy consumption per household (HEC) was estimated to be 92.6 GJ per year. In comparison, the actual weighted average consumption for the sample was 96.6 GJ per year.

Exhibit 13.7: Unit Energy Consumption Estimates – Whistler

End Use	Sample Size (unweighted)	Penetration (% presence)	2008 UEC Estimate (GJ/year)	Average Consump-tion per Household (GJ/year)	Average Consump-tion per Household (%)
Primary Space Heating	101	80%	66.9	53.2	57%
Secondary Space Heating	18	14%	33.6*	4.7*	5%
Water Heating	88	69%	18.5	12.8	14%
Decorative Fireplace	36	28%	22.2	6.3	7%
Heater Fireplace	49	38%	15.8	6.1	7%
Range, Cook Top, Oven	67	53%	4.8	2.6	3%
Barbeque	59	47%	7.9	3.7	4%
Dryer	10	8%	3.3*	0.3*	<1%
Pool	4	3%	**	**	**
Hot Tub	11	9%	19.5*	1.7*	2%
Household Consumption					
Estimated				**92.6**	
Actual				**96.6**	

* Small sample size (less than 30 households with end use present).
** Insufficient sample size (less than 5 households with end use present)

13.3.5 Fort Nelson

Exhibit 13.8 shows weighted average UECs for the Fort Nelson region. The weather-normalized, weighted average annual energy consumption per household (HEC) was estimated to be 130.2 GJ per year. In comparison, the actual weighted average consumption for the sample was 150.4 GJ per year.

Exhibit 13.8: Unit Energy Consumption Estimates – Fort Nelson

End Use	Sample Size (unweighted)	Penetration (% presence)	2008 UEC Estimate (GJ/year)	Average Consump-tion per Household (GJ/year)	Average Consump-tion per Household (%)
Primary Space Heating	131	94%	113.4	106.0	81%
Secondary Space Heating	2	1%	**	**	**
Water Heating	116	83%	22.7	18.8	14%
Decorative Fireplace	6	4%	19.3*	0.8*	1%
Heater Fireplace	21	15%	14.7*	2.2*	2%
Range, Cook Top, Oven	29	21%	5.3*	1.1*	1%
Barbeque	17	12%	7.9*	1.0*	1%
Dryer	12	9%	3.3*	0.3*	<1%
Pool	1	1%	**	**	**
Hot Tub	-	0%	**	**	**
Household Consumption					
Estimated				**130.2**	
Actual				**150.4**	

* Small sample size (less than 30 households with end use present).
** Insufficient sample size (less than 5 households with end use present).

13.4 UECs by Dwelling Type

Exogenous variables were incorporated into the CDA models for space heating (primary and secondary) and water heating to disaggregate by the following dwelling types: single family dwelling, vertical subdivisions and other multi-family dwellings.

13.4.1 Primary Space Heating

Exhibit 13.9 shows estimated primary gas space heating unit energy consumption by geographic region and housing type. As expected, space heating UECs for VSDs and MFDs were lower than SFDs. This is consistent with the size and characteristics (e.g., fewer outside walls) of VSDs and MFDs.

Exhibit 13.9: Primary Gas Space Heating UECs by Dwelling Type (GJ/year)

Dwelling Type	LM	INT	TGVI	TGW	FN	2008 TG Average
SFD	64.6	52.3	43.9	77.7	113.4	59.5
VSD	5.7	13.9	**	-	-	7.1
MFD	34.4	33.0	21.0	33.4*	-	33.5
Average	**62.0**	**51.6**	**43.0**	**66.9**	**113.4**	**57.8**

* Small sample size (less than 30 households with end use present).
** Insufficient sample size (less than 5 households with end use present).

13.4.2 Secondary Space Heating

Secondary gas space heating unit energy consumption also varies between region and housing type, as shown in Exhibit 13.10.

Exhibit 13.10: Secondary Gas Space Heating UECs by Dwelling Type (GJ/year)

Dwelling Type	LM	INT	TGVI	TGW	FN	2008 TG Average
SFD	20.1*	40.0*	20.7	42.6*	**	26.0
VSD	2.7*	**	-	-	-	2.6
MFD	9.7*	21.3*	10.0	**	-	10.7
Average	**18.1**	**39.3**	**19.9**	**33.6**	**	**23.2**

* Small sample size (less than 30 households with end use present).
** Insufficient sample size (less than 5 households with end use present).

13.4.3 Water Heating

Consistent with their tendency towards smaller household sizes (i.e., number of people per home), UECs for gas water heating for VSDs and MFDs are lower than SFDs (Exhibit 13.11).

Exhibit 13.11: Gas Water Heating UECs by Dwelling Type (GJ/year)

Dwelling Type	LM	INT	TGVI	TGW	FN	2008 TG Average
SFD	20.6	18.9	19.0	19.8	22.7	20.0
VSD	17.4	13.2	**	-	-	16.5
MFD	18.3	16.0	14.7	14.0*	-	17.7
Average	**20.4**	**18.8**	**18.8**	**18.5**	**22.7**	**19.8**

* Small sample size (less than 30 households with end use present).
** Insufficient sample size (less than 5 households with end use present).

13.5 Limitations to the CDA Estimates

The results from the CDA should be interpreted with some caution as they are subject to the following limitations:

- The estimated consumption levels of high-penetration end uses may mask the effects of other end uses and/or partially capture the base consumption load of a household.
- The effects of low-penetration end uses (e.g. gas dryers or barbeques) are difficult to estimate because of small sample sizes.
- Consumption values could not be accurately estimated for some regions and dwelling types due to small sample sizes.
- Some information collected through the self-reported customer surveys may be unreliable.
- The rich model specifications originally developed for some end uses had to be simplified because of unreasonable regression results.

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Appendix A

Questionnaire
Reminder Card

Terasen Gas
2008 Residential Survey

▲

Thank you for completing this survey. Please have the person in your home who is most responsible for home maintenance and repair complete this questionnaire. Also please ensure that the survey responses refer to the residence located at the address shown on the attached label below.

Win a $500 Gift Certificate
By completing this survey, your name will be entered into a draw to win one of two $500 gift certificates to a home improvement / hardware store near you. Contest details are contained in the covering letter.

The information you provide will be used to better understand how residential customers use energy; to assist in forecasting natural gas loads, and help design energy efficiency programs. All individual data will be kept confidential.

Receive an additional chance to win a $500 gift certificate by completing your survey online.

You can choose to complete this survey online by going to www.nrgsurveys.ca/terasengas and entering the random ID code that appears on the label below.

Instructions for Completing the Mail Survey
Some questions require you to place an "X" in the appropriate box, for example: ▲

Do you rent or own this residence? Rent ☒ Own ☐

Some questions require you to fill in a number, for example: " 23 " years

Some questions allow you to check several answers. These questions will have the instruction "check all that apply."

You will notice marks ▲ throughout the survey. These marks are to facilitate reading your survey by scanner.

When you have completed the survey, please put the questionnaire in the enclosed envelope. No postage is needed. Surveys are due by December 5th, 2008.

If you have mislaid the return envelope, please mail the questionnaire to:

NRG Research Group
1380 – 1100 Melville St.
Vancouver, BC V6E 4A6

A. YOUR RESIDENCE

A1. Is this residence a:

Single family dwelling (detached) ☐
Duplex (2 units attached) ☐
Row house or townhouse (3 or more units attached, each with a separate entrance) ☐
Apartment / Condominium ☐
▲ Mobile home ☐
Other ☐

A2. IF ROW HOUSE OR TOWNHOUSE: Is your townhouse or row house an end unit (neighbour on one side only) or a middle unit (neighbours on both sides)?

End unit ☐ Middle unit ☐

A3. IF APARTMENT / CONDOMINIUM: Please select the category that best describes the relative location of your apartment / condominium within the building:

End or corner unit – top floor ☐
End or corner unit – one or more floors below top floor ☐
Middle unit – top floor ☐
Middle unit – one or more floors below top floor ☐

A4. IF APARTMENT / CONDOMINIUM: How many stories does your building have? Include penthouses but exclude levels used only for parking or retail.

_____ stories

A5. When was this residence built?

Before 1950 ☐ 1976-1985 ☐ 1996 -2005 ☐
1950-1975 ☐ 1986-1995 ☐ 2006 or later ☐
Don't know ☐

A6. Is this your principal residence? Yes ☐ No ☐

A7. How many weeks per year is the residence at the address on this survey occupied?

______ weeks Always occupied ☐

A8. How many years have you lived in this residence? ______ years

A9. Do you rent or own this residence? Rent ☐ Own ☐

A10. Do you pay a monthly rent or maintenance fee?

	Yes	No	Don't know
Monthly rent	☐	☐	☐
Maintenance fee	☐	☐	☐

IF YOU DO NOT PAY MONTHLY RENT OR MAINTENANCE FEES OR DON'T KNOW → GO TO QUESTION A12

A11. Which of the following are included in your monthly rent or maintenance fee?

▲

	Yes	No	Don't know	Not applicable
Space heating	☐	☐	☐	☐
Water heating	☐	☐	☐	☐
Fireplace fuel	☐	☐	☐	☐
Fuel for gas cooking	☐	☐	☐	☐
Fuel for gas clothes drying	☐	☐	☐	☐

A12. How many rooms in this residence are heated? (Do NOT count bathrooms, closets or hallways)

Number of rooms that are always heated ______
★ Number of rooms that are sometimes heated ______
Number of rooms that are rarely or never heated ______

A13. What is the height of the ceilings in your residence, excluding the basement? Please indicate the percentage of the residence with each ceiling height. Choose the closest height. Your answers should sum to 100%.

	Percentage
8 feet	______
9 feet	______
10 feet	______
More than 10 feet	______
TOTAL	**100%**

A14. How many stories does your residence have above ground excluding the basement?
If Apartment/Condominium, only answer for your unit. _____stories

A15. What is the total floor area of this residence, including basement and / or unfinished areas but excluding the garage or carport?
_____sq. feet OR _____sq. metres

A16. What type of basement does your residence have? ★

No basement ☐ → **GO TO QUESTION A18**

Partial basement ☐
Full basement ☐
→ Completely under ground ☐ / Completely above ground ☐ / Partially above ground ☐
→ Unfinished ☐ / Partially finished ☐ / Completely finished ☐

Crawl space ☐ → **GO TO QUESTION A17**

A17. During the heating season, is your basement or crawl space usually heated?
Yes ☐ No ☐

A18. Is the insulation level in this residence less than average, average or more than average? Please choose the answer that best describes the insulation level in each of the following areas:

	Ceiling / Attic	Walls	Basement
Less than average (about R6 or 1.75 inches of insulation or less)	☐	☐	☐
Average (about R12 or 3.5 inches of insulation)	☐	☐	☐
More than average (about R18 or 5.25 inches of insulation or more)	☐	☐	☐
Don't know	☐	☐	☐
No Basement →			☐

A19. Please estimate the percentage of windows that are:
Your answers should sum to 100%

	% of Windows	Argon Gas Fill? Yes	No	Don't know
Single pane regular glass	______			
Double pane regular glass	______	☐	☐	☐
Double pane with low emissivity (Low-E) coating	______	☐	☐	☐
Triple pane regular glass	______	☐	☐	☐
Triple pane with low emissivity (Low-E) coating	______	☐	☐	☐
Other – Specify _________________	______	☐	☐	☐
TOTAL	**100%**			

★

A20. What % of the windows in your residence are Energy Star® qualified?

Energy Star® qualified products are some of the most energy efficient products that you can buy today. Energy Star products will display the Energy Star logo on the product or its packaging

0% ☐
1% - 25% ☐
26% - 50% ☐
51% - 75% ☐
76% - 100% ☐
Don't know ☐

A21. Please indicate the number of outside doors this residence has by type of door:

	Number
Standard wood doors	____
★ Standard wood doors with aluminium storm doors	____
Insulated steel or fibreglass doors	____
Glass doors with wooden frames	____
Glass doors with aluminium frames	____
Glass doors with vinyl frames	____

B. SPACE HEATING

B1. What is the main fuel used to heat this residence? The main fuel is the one that provides most of the heat in your house during a typical year. If you have hot water heating please specify the fuel used to heat the hot water. (check one fuel only)

Electricity ☐ Piped propane ☐ Oil ☐ Other ☐
Natural gas ☐ Bottled propane ☐ Wood ☐ Don't know ☐

B2. Have you changed from one main fuel to another to heat this residence within the past five years?

Yes ☐ → **GO TO QUESTION B3**
No ☐ → **GO TO QUESTION B4**

B3. What was the previous main space heating fuel? (check one fuel only)

Electricity ☐ Piped propane ☐ Oil ☐ Other ☐
Natural gas ☐ Bottled propane ☐ Wood ☐ Don't know ☐

B4. Please indicate any additional or supplementary fuel(s) used to heat this residence (check all that apply) and which fuel is used the most (check one only). Note: most heat pumps use a supplementary fuel.

	All additional / supplementary fuels (check all that apply)	Most used supplementary fuel (check one only)
Electricity	☐	☐
Natural gas	☐	☐
Piped propane	☐	☐
Bottled propane	☐	☐
Oil	☐	☐
★ Wood	☐	☐
Other	☐	☐
Don't know	☐	☐

UNLESS OTHERWISE STATED, ANY REFERENCES TO "GAS" FROM THIS POINT FORWARD IN THE SURVEY MEAN EITHER NATURAL GAS OR PIPED PROPANE GAS.

B5. Do you have a gas furnace, a gas boiler, or neither?

Gas boiler ☐ → **GO TO QUESTION B6**
▼ Gas furnace ☐ → **GO TO QUESTION B7**
Neither ☐ → **GO TO QUESTION B12**

Domestic Hot Water Tanks Versus Boilers

A domestic hot water tank supplies hot water for bathing, washing dishes, washing clothes, etc.

A boiler provides hot water to heat your house – typically using radiant in-floor piping or upright / baseboard style radiators. Some space heat boilers also heat water in a separate tank for domestic use.

B6. Boiler efficiency refers to how much useful heat your boiler extracts from the gas. The higher the efficiency of the boiler, the less fuel required to heat your house. Boilers can be categorized as standard efficiency or high efficiency.

What is the efficiency of your boiler? ▼

Standard efficiency gas boiler (80% to 85% efficiency) ☐
High efficiency gas boiler (90% or higher efficiency) ☐ } **GO TO QUESTION B9**
Don't know ☐

B7. If your furnace has a pilot light, about how many months per year is the pilot light turned off? The pilot light is a small flame that is used to ignite or start the furnace when heat is required.

______ months per year
Pilot light is turned off, but not sure for how long ☐
Pilot light is never turned off ☐
Furnace does not have a pilot light ☐
Don't know ☐

B8. Furnace efficiency refers to how much useful heat your furnace extracts from the gas. The higher the efficiency of the furnace, the less fuel required to heat your house. Furnaces are categorized as standard efficiency, mid-efficiency, or high efficiency.

Three types of gas furnaces		
Standard efficiency	**Mid-efficiency**	**High efficiency**
- at least 13 years old - uses a pilot light - metal flue that vents through the - roof - efficiency less than 78%	- no pilot light, uses an igniter instead - metal flue that vents through the roof - 78% - 85% efficiency	- no pilot light - plastic flue - flue vents either through the roof or the side of the house - 90% efficiency or higher - Energy Star® qualified

What is the efficiency of your furnace?

▼

Standard efficiency gas furnace (less than 78% efficiency) ☐
Mid-efficiency gas furnace (78% to 85% efficiency) ☐
High efficiency gas furnace (90% efficiency or higher) ☐
Don't know ☐

B9. How old is your gas furnace or gas boiler?

_____ years Don't know ☐

FOR OFFICE USE ONLY

B10. Have you installed a gas furnace or gas boiler in the past five years?

Yes ☐ → **GO TO QUESTION B11**
No ☐
Don't know ☐ } → **GO TO QUESTION B12**

▼

B11. What was the main reason you installed the gas furnace or gas boiler? (check one reason only)

New home ☐
Wanted to change to gas ☐
Wanted more efficient furnace or boiler ☐
Existing furnace or boiler had failed ☐
Anticipated furnace or boiler failure ☐
House was too cold ☐
Heated floor area increased due to additions or renovations ☐
Wanted an environmentally friendly fuel ☐
Wanted a lower cost fuel ☐
Other (please specify)__________________ ☐

B12. Please check the main method used to heat this residence, then the second most used method, and then all other methods used to heat this residence.

▼	Main method (check one only)	Second most used method (check one only)	All other methods (check all that apply)
Central forced air furnace	☐	☐	☐
Wired-in electric heater (baseboards)	☐	☐	☐
Wired-in electric wall heater (fan forced)	☐	☐	☐
Hot water baseboards	☐	☐	☐
Hot water radiant in-floor / under floor heat	☐	☐	☐
Electric radiant heat (floors, walls, and/or ceilings)	☐	☐	☐
Gas wall heater	☐	☐	☐
Portable electric heaters	☐	☐	☐
Wood stove	☐	☐	☐
Gas heater stove	☐	☐	☐
Heat pump – air source	☐	☐	☐
Heat pump – ground source	☐	☐	☐
Wood burning fireplace	☐	☐	☐
Electric fireplace	☐	☐	☐
Gas fireplace	☐	☐	☐
Other	☐	☐	☐

B13. Please indicate whether you always, usually, occasionally or never specifically take the following actions to conserve energy in your home (check one box per row).

Always Usually -nally

	Never	know	Occasion able		Don't	Not Applic-
Change furnace filter regularly	☐	☐	☐	☐	☐	☐
Service heating system annually by contractor	☐	☐	☐	☐	☐	☐
Service heating system annually myself	☐	☐	☐	☐	☐	☐
▼ Duct cleaning	☐	☐	☐	☐	☐	☐

B14. Do you use one or more programmable thermostats in your residence?

Yes ☐ No ☐ Don't know ☐

B15. Other than opening doors or windows, some homes have another way to bring in fresh air from the outdoors to maintain the quality of indoor air. Please indicate which of the following best describes the ventilation system used in this residence (check one only):

Mechanical ventilation system separate from the heating system that includes air intakes and vents in various rooms. May include a heat recovery ventilator (HRV)	☐
Primary exhaust fan (such as a bathroom fan) that automatically turns on and off for parts of the day	☐
Furnace fan that automatically turns on and off for part of the day even when the furnace is not providing heat	☐
Other (please specify)________________________________	☐
None of the above	☐
Don't know	☐

C. FIREPLACES AND HEATING STOVES

Gas fireplace and stove types

Decorative fireplaces – Provide ambiance but have little or no heating ability. The firebox is typically steel or masonry, and the hearth is typically open to the room (no fixed glass front).

Heater type fireplaces (built-ins and inserts) – These fireplaces are efficient heaters with glass fronts and may have features such as fans and thermostatic control. They may be built-in at the time of construction, or inserted into an existing masonry or other fireplace as an upgrade.

Free standing fireplaces and heating stoves – These are stand alone units that that can be used for both ambiance and heating. Gas heater stoves resemble wood stoves in appearance but use gas instead of wood.

Many homes are equipped with fireplaces or heating stoves. Some provide ambiance but little or no heat, while others can be used to heat one or more rooms.

C1 Do you have a fireplace or heating stove in this residence?

.

Yes ☐ → **GO TO QUESTION C2**
No ☐ → **GO TO SECTION D**

C2. How many of the following types of fireplaces and heating stoves do you have? For each type, please indicate whether they are used primarily for heating, ambiance or both.

	Number (check one)				Used primarily for:		
	1	2	3	4+	Heating	Ambiance	Both
Gas (decorative)	☐	☐	☐	☐	☐	☐	☐
Gas (heater type)	☐	☐	☐	☐	☐	☐	☐
Gas (free standing)	☐	☐	☐	☐	☐	☐	☐
Electric	☐	☐	☐	☐	☐	☐	☐
Wood burning fireplace	☐	☐	☐	☐	☐	☐	☐
Wood burning stove	☐	☐	☐	☐	☐	☐	☐
Other_______________	☐	☐	☐	☐	☐	☐	☐

C3. How many hours in total are the fireplaces and heater stoves in use during a typical week in each of the following seasons? Please sum the hours for all fireplaces and heater stoves for a typical week in each season.

Summer _____ hours per week
Fall _____ hours per week
Winter _____ hours per week
Spring _____ hours per week

C4. GAS FIREPLACES ONLY: If your fireplace has a pilot light, about how many months per year is the pilot light turned off? The pilot light is a small flame that is used to ignite the fireplace when it is turned on.

______ months per year

Pilot light is turned off, but not sure for how long ☐
Pilot light is never turned off ☐
Fireplace does not have a pilot light ☐
Don't know ☐

D. DOMESTIC WATER HEATING

D1. How many water heaters are there in this residence? If you live in an apartment, townhouse, or row house where hot water is centrally provided to all units (from outside your unit), please check "none".

1 ☐
2 ☐
3 ☐
None ☐ → **GO TO QUESTION D10**

D2. What type of fuel does your water heater(s) use? Check one only for each heater that you own or rent.

	Heater 1	Heater 2	Heater 3
Electricity	☐	☐	☐
Natural gas	☐	☐	☐
Piped propane	☐	☐	☐
Bottled propane	☐	☐	☐
Solar	☐	☐	☐
Oil	☐	☐	☐
Geothermal	☐	☐	☐
Other	☐	☐	☐

D3. Please indicate whether the water heater(s) uses solar energy to pre-warm or supplement the water heating process.

	Heater 1	Heater 2	Heater 3
Yes	☐	☐	☐
No	☐	☐	☐

D4. Have you changed the water heating fuel at this residence within the past five years?

Yes ☐ **→GO TO QUESTION D5**
No ☐ **→GO TO QUESTION D6**

D5. What was the previous water heater fuel?

	Heater 1	Heater 2	Heater 3
Electricity	☐	☐	☐
Natural gas	☐	☐	☐
Piped propane	☐	☐	☐
Bottled propane	☐	☐	☐
Solar	☐	☐	☐
Oil	☐	☐	☐
Geothermal	☐	☐	☐
Other	☐	☐	☐

D6. What types of water heater(s) are there in this residence?

Tankless (Instantaneous) Water Heaters:
These compact units provide hot water on demand without the need for a storage tank. They use either gas or electricity to operate.

Condensing Water Heaters:
These high efficiency water heaters use a heat exchanger to extract heat from the flue gases. Can be vented to the outside using plastic pipe.

	Heater 1	Heater 2	Heater 3
Storage water heater (tank) – vent through roof	☐	☐	☐
Storage water heater (tank) – vent through side wall	☐	☐	☐
Storage water heater (tank) – no vent	☐	☐	☐
Tankless (instantaneous) water heater	☐	☐	☐
Combined space and water heater	☐	☐	☐
Condensing water heater	☐	☐	☐
Don't know	☐	☐	☐

D7. How old is (are) your water heater(s)?

Heater 1 _____years Don't know ☐
Heater 2 _____years Don't know ☐
Heater 3 _____years Don't know ☐

D8. Have you installed a water heater within the past five years?

Yes ☐ **→GO TO QUESTION D9**
No ☐ **→GO TO QUESTION D10**

D9. What was the main reason you installed the water heater?

- New home ☐
- Wanted to change to gas ☐
- Wanted more efficient water heater ☐
- Water heater had failed ☐
- Anticipated water heater failure ☐
- Needed more hot water ☐
- Wanted quicker hot water recovery ☐
- Wanted an environmentally friendly fuel ☐
- Wanted a cheaper fuel ☐
- Other ☐

D10. Please indicate the total number of the following for your residence:

- Number of showerheads ______
- Number of low flow showerheads ______
- Number of water heater blankets ______
- Number of dishwasher loads per week ______
- Number of loads of laundry per week ______
- Number of baths per week ______
- Number of showers per week ______

D11. Please estimate the total amount of time the shower(s) is in use on a typical weekday (total for all members of this residence).

_____ minutes per day   No showers – take baths only ☐

E. APPLIANCES

E1. Please indicate the number of each of the following appliances in use in this residence. For each appliance please indicate the approximate age (your best guess is fine).

		Number in Use				Age of Appliance (in years)		
		0	1	2	3+	#1	#2	#3
COOKING	Electric range	☐	☐	☐	☐	_____	_____	_____
	Gas range	☐	☐	☐	☐	_____	_____	_____
	Electric cook top	☐	☐	☐	☐	_____	_____	_____
	Gas cook top	☐	☐	☐	☐	_____	_____	_____
	Electric wall oven	☐	☐	☐	☐	_____	_____	_____
	Gas wall oven	☐	☐	☐	☐	_____	_____	_____
	Microwave oven	☐	☐	☐	☐	_____	_____	_____
	Gas barbeque (piped gas)	☐	☐	☐	☐	_____	_____	_____
	Gas barbeque (bottled gas)	☐	☐	☐	☐	_____	_____	_____
COOLING	Refrigerator	☐	☐	☐	☐	_____	_____	_____
	Stand-alone freezer	☐	☐	☐	☐	_____	_____	_____
CLEANING	Dishwasher	☐	☐	☐	☐	_____	_____	_____
	Top loading clothes washer	☐	☐	☐	☐	_____	_____	_____
	Front loading clothes washer	☐	☐	☐	☐	_____	_____	_____
	Electric clothes dryer	☐	☐	☐	☐	_____	_____	_____
	Gas clothes dryer	☐	☐	☐	☐	_____	_____	_____
AIR CONDITIONING AND HEATING								
	Electric central air conditioner	☐	☐	☐	☐	_____	_____	_____
	Electric wall unit	☐	☐	☐	☐	_____	_____	_____
	Portable air conditioner	☐	☐	☐	☐	_____	_____	_____
	Humidifier	☐	☐	☐	☐	_____	_____	_____
	Air source heat pump	☐	☐	☐	☐	_____	_____	_____
	Ground source heat pump	☐	☐	☐	☐	_____	_____	_____

Gas outdoor heater (piped gas)	☐	☐	☐	☐	_____	_____	_____
Gas outdoor heater (bottled gas)	☐	☐	☐	☐	_____	_____	_____
Dehumidifier	☐	☐	☐	☐	_____	_____	_____
Heat recovery ventilator	☐	☐	☐	☐	_____	_____	_____

E2. Of the following appliances you own, please indicate whether any are Energy Star® qualified:

(check all that apply)

Refrigerator ☐
Freezer ☐
Dishwasher ☐
Clothes washer ☐
Clothes dryer ☐
Air conditioner ☐
Dehumidifier ☐

F. SWIMMING POOLS AND HOT TUBS

F1. Do you have a swimming pool at this residence?
Yes, indoor ☐
Yes, outdoor ☐ } **GO TO QUESTION F2**
No ☐ → **GO TO QUESTION F6**

F2. Is this pool for the exclusive use of this residence (example: backyard pool in a single family dwelling) or shared with other residences (example: pool in an apartment / condominium / or townhouse complex)?
Exclusive use only ☐ → **GO TO QUESTION F3**
Share with others ☐ → **GO TO QUESTION F6**

F3. Please indicate the type of fuel used by the pool heater and whether solar energy is used to supplement the water heating process.

	Fuel type	Solar supplementary heating
Solar	☐	N/A
Natural gas	☐	☐
Electric	☐	☐
Propane	☐	☐
Other	☐	☐
Not heated	☐ → **GO TO QUESTION F6**	

F4. Please indicate how many months per year your pool is heated ______ months per year

F5. Do you cover the pool when not in use? Yes ☐ No ☐

F6. Do you have a hot tub at this residence?
Yes, indoor ☐
Yes, outdoor ☐ } **GO TO QUESTION F7**
No ☐ → **GO TO SECTION G**

F7. Is this hot tub for the exclusive use of this residence (example: hot tub in a single family dwelling) or shared with other residences (example: hot tub in an apartment / condominium / or townhouse complex)?
Exclusive use only ☐ → **GO TO QUESTION F8**
Share with others ☐ → **GO TO SECTION G**

F8. What type of fuel does the hot tub heater use?
Natural gas ☐
Propane ☐
Solar ☐
Electric ☐
Other ☐

F9. How many months per year is your hot tub heated? _____ months

F10. Do you cover the hot tub when not in use? Yes ☐ No ☐

G. ENERGY USE AND RENOVATIONS

G1. Please indicate the renovations or actions you have undertaken at this residence within the last <u>five years</u> <u>AND</u> whether you did it yourself, used a contractor, or both did it yourself and used a contractor. Please also indicate the year the renovation occurred.

	Did this	Did it myself	Used a contractor	Both	Year
Purchased energy efficient appliance(s)	☐	N/A	N/A	N/A	_____
Started using, or increased usage of, portable electric heater(s)	☐	N/A	N/A	N/A	_____
Improved insulation in walls or attic	☐	☐	☐	☐	_____
Installed weather stripping or caulking	☐	☐	☐	☐	_____
Replaced windows (any kind)	☐	☐	☐	☐	_____
Replaced window(s) with energy efficient window(s)	☐	☐	☐	☐	_____
Installed storm door(s)	☐	☐	☐	☐	_____
Installed insulated steel or fibreglass door(s)	☐	☐	☐	☐	_____
Installed low flow shower head(s)	☐	☐	☐	☐	_____
Installed programmable thermostat(s)	☐	☐	☐	☐	_____
Had a home energy audit	☐	☐	☐	☐	_____
Installed duct insulation or sealing	☐	☐	☐	☐	_____
Installed a hot water heater blanket	☐	☐	☐	☐	_____
Installed a swimming pool heater	☐	☐	☐	☐	_____
Installed a hot tub heater	☐	☐	☐	☐	_____
None of the above	☐				

G2. Did you undertake any renovations that involved fireplaces or heating stoves at this residence within the last five years?

Yes ☐ → **GO TO QUESTION G3**
No ☐ → **GO TO QUESTION G4**

G3. Please indicate renovations or other changes to fireplaces or heating stoves you made at this residence within the last <u>five years</u> <u>AND</u> whether you did it yourself, used a contractor, or both did it yourself and used a contractor. Please also indicate the year the renovation or change occurred.

Note: there several types of fireplaces available in the market today. Please read carefully and select the category that best describes your situation.

	Did this	Did it myself	Used a contractor	Both	Year
Installed free standing gas fireplace or heating stove	☐	☐	☐	☐	_____
Installed decorative gas fireplace	☐	☐	☐	☐	_____
Installed electric fireplace	☐	☐	☐	☐	_____
Installed wood stove	☐	☐	☐	☐	_____
Installed gas heater type fireplace <u>insert</u> in existing wood fireplace	☐	☐	☐	☐	_____
Installed energy efficient wood burning fireplace <u>insert</u> in existing wood fireplace	☐	☐	☐	☐	_____
Removed or disconnected gas fireplace	☐	☐	☐	☐	_____
Removed wood fireplace or wood stove	☐	☐	☐	☐	_____
Installed glass fireplace doors	☐	☐	☐	☐	_____
Replaced decorative gas fireplace with heater type insert	☐	☐	☐	☐	_____

G4. Please indicate renovations you plan to undertake at this residence within the next two years and whether you plan to do it yourself, use a contractor or both do it yourself and use a contractor.

	Plan to do this	Do it myself	Use a contractor	Both
Purchase energy efficient appliance(s)	☐	N/A	N/A	N/A
Purchase portable electric heater(s)	☐	N/A	N/A	N/A
Improve insulation in walls or attic	☐	☐	☐	☐
Install weather stripping or caulking	☐	☐	☐	☐
Replace windows (any kind)	☐	☐	☐	☐
Replace window(s) with energy efficient window(s)	☐	☐	☐	☐
Install storm door(s)	☐	☐	☐	☐
Install insulated steel or fibreglass door(s)	☐	☐	☐	☐
Install low flow showerhead(s)	☐	☐	☐	☐
Install programmable thermostat(s)	☐	☐	☐	☐
Have a home energy audit	☐	☐	☐	☐
Install duct insulation or sealing	☐	☐	☐	☐
Install a hot water heater blanket	☐	☐	☐	☐
Install mid-efficiency gas furnace	☐	☐	☐	☐
Install high efficiency gas furnace	☐	☐	☐	☐
Install swimming pool heater	☐	☐	☐	☐
Install hot tub heater	☐	☐	☐	☐
None of the above	☐			

G5. Do you plan to undertake any renovations that involve fireplaces or heater stoves at this residence within the next two years?

Yes ☐ → **GO TO QUESTION G6**
No ☐ → **GO TO QUESTION G7**

G6. Please indicate the renovations that involve fireplaces or heating stoves you plan to undertake at this residence within the next two years and whether you plan to do it yourself, use a contractor or both do it yourself and use a contractor.

Note: there several types of fireplaces available in the market today. Please read carefully and select the category that best describes your renovation plan involving fireplaces.

	Plan to do this	Do it myself	Use a contractor	Both
Install free standing gas fireplace or heating stove	☐	☐	☐	☐
Install decorative gas fireplace	☐	☐	☐	☐
Install electric fireplace	☐	☐	☐	☐
Install wood stove	☐	☐	☐	☐
Install gas heater type fireplace insert in existing wood fireplace	☐	☐	☐	☐
Install energy efficient wood burning fireplace insert in existing wood fireplace	☐	☐	☐	☐
Remove or disconnect gas fireplace	☐	☐	☐	☐
Remove wood fireplace or wood stove	☐	☐	☐	☐
Install glass fireplace doors	☐	☐	☐	☐
Replace decorative gas fireplace with heater type insert	☐	☐	☐	☐

G7. IF YOU UNDERTOOK OR PLAN TO UNDERTAKE ANY OF THE RENOVATIONS FROM G1 THROUGH G6: Why did you undertake or why do you plan to undertake these renovations?
(check all that apply)

Response to increases in the price of energy ☐
Reduce energy costs ☐
Increase resale value of home ☐
Increase comfort of home ☐
Expect energy prices to rise in the future ☐
Part of general home renovation ☐
Other (please specify) ______________________________ ☐
____

H. MANAGING HOUSEHOLD ENERGY USE

This section is intended to help Terasen Gas understand how you use / manage energy in your household.

H1. At what temperature do you usually keep your home when someone is home, when no one is home, and during the night?

	Degrees C		Degrees F
When someone is home	___	OR	___
When no one is home	___	OR	___
During the night	___	OR	___

H2. How often does your household turn down the temperature at night when you go to bed, either manually or using a programmable thermostat?

Always	Usually	Occasionally	Never	Don't know
☐	☐	☐	☐	☐

H3. How often does your household turn down the temperature during the day when no one is at home, either manually or using a programmable thermostat?

Always	Usually	Occasionally	Never	Don't know
☐	☐	☐	☐	☐

H4. How many extra bedrooms are there in your home? (extra means that no one sleeps in the bedroom on a regular basis)

None ☐ 2 ☐ More than 3 ☐
1 ☐ 3 ☐ Don't know ☐

H5. Do you have a way to reduce the temperature in unoccupied parts of the home, such as by closing heating registers and closing doors, or turning down a thermostat if you have zoned heating (such as radiant hot water or electric baseboards with a thermostat in each room)?

Yes ☐ No ☐ Don't know ☐

H6. How often do you try to keep these unoccupied areas cooler than the rest of the home?

Always	Usually	Occasionally	Never	Don't know
☐	☐	☐	☐	☐

H7. Please indicate how effective the draft-proofing in your home is.

Home is always drafty ☐ Home is not at all drafty ☐
Home is somewhat drafty ☐ Don't know ☐

H8. How often does your household check and maintain the weather stripping? (check one only)

More than once a year ☐ Once every two years ☐ Never ☐
Once a year ☐ As required, but longer than two years ☐ Don't know ☐

H9. How effective would you say your household's draft-proofing maintenance has been?

Home is much less drafty due to our efforts ☐ There has been no noticeable difference ☐
Home is somewhat less drafty due to our efforts ☐ Don't know ☐

H10. Do you install storm windows (glass) or plastic sheeting for the single paned windows? These may be installed on either the inside or outside of the home.

Yes ☐ No ☐ Don't know ☐

H11. How often do you use window coverings such as drapes, blinds, or shutters to reduce heat loss in winter?

Always	Usually	Occasionally	Never	No window coverings	Don't know
☐	☐	☐	☐	☐	☐

H12. How often do you open windows to let in fresh air during the winter?

Always	Usually	Occasionally	Never	Don't know
☐	☐	☐	☐	☐

▼

H13. What share of your laundry is done with cold water wash and rinse?

0% ☐	20% - 39% ☐	60% - 79% ☐	100% ☐
Less than 20% ☐	40% - 59% ☐	80% - 99% ☐	Don't know ☐

H14. How much more cold water wash and rinse could you do?

None, already doing all I can ☐	Between 10 – 14% more ☐
Less than 5% more ☐	Between 15 – 19% more ☐
Between 5 – 9% more ☐	20% or more ☐

H15. Have you ever checked the temperature of the hot water in your home?

Yes ☐ →**GO TO QUESTION H16**
No ☐ →**GO TO QUESTION H17**

H16. Did you increase or decrease the temperature of the water, or did you leave it unchanged?

Increase ☐
Decrease ☐
Left it unchanged ☐

H17. When you are away from your home for more than 2-3 days, how often do you turn off the water heater or use the vacation setting? Note: a vacation setting is not available on some water heaters.

▼

Always	Usually	Occasionally	Never	Don't know
☐	☐	☐	☐	☐

I. PRODUCTS AND SERVICES

I1. During the past five years, have you participated in a Terasen Gas, government, or other program to reduce energy use in your home?

▼

	Terasen Gas	Gov't	Other
Yes	☐	☐	☐
No	☐	☐	☐
Don't know	☐	☐	☐

2. On a scale of one to four, where one is not at all interested and four is very interested, how interested would you be in the following products and services?

	Not at all interested 1	2	3	Very interested 4
Home energy audit to determine main energy uses in the home and identify opportunities to save energy	☐	☐	☐	☐
Do-it-yourself online energy audit	☐	☐	☐	☐
Furnace tune-up to ensure that furnace is working safely and efficiently	☐	☐	☐	☐
Program to replace furnace with high efficiency furnace	☐	☐	☐	☐
Program to replace gas fireplace with high efficiency gas fireplace	☐	☐	☐	☐
Program to install high efficiency gas fireplace	☐	☐	☐	☐
Program to replace clothes washer with high efficiency clothes washer	☐	☐	☐	☐
Program to replace dishwasher with high efficiency dishwasher	☐	☐	☐	☐
Program to replace electric range or cook top with gas range or cook top	☐	☐	☐	☐
Program to replace electric clothes dryer with gas dryer	☐	☐	☐	☐
Program to replace water heater with high efficiency water heater	☐	☐	☐	☐
Program to upgrade ceiling and wall insulation	☐	☐	☐	☐
Program to improve draft-proofing	☐	☐	☐	☐

▼

J. ATTITUDES TOWARDS ENERGY USE

★

J1. In order to serve you better, we would like to understand your views on a number of energy related issues. For the following set of statements, please check the answer that most accurately reflects your agreement or disagreement with the statement.

On a scale of one to five, where one means that you strongly disagree and five means that you strongly agree, please indicate whether you agree or disagree with the following statements on energy and natural gas usage.

	Strongly disagree 1	2	Neither agree nor disagree 3	4	Strongly agree 5
★ There are many ways that a person can save energy - when you add them up, they result in substantial savings	☐	☐	☐	☐	☐
By making my home more energy efficient, I am helping to do my part for the environment	☐	☐	☐	☐	☐
I think natural gas is a clean and efficient energy source	☐	☐	☐	☐	☐
Members of my household regularly limit the length of their showers to save energy	☐	☐	☐	☐	☐
I don't want to think about natural gas or electricity, I simply want it to work	☐	☐	☐	☐	☐
I consider natural gas to be a safe energy source	☐	☐	☐	☐	☐
There is an adequate supply of domestically produced electricity in British Columbia	☐	☐	☐	☐	☐

I have a good understanding of energy issues in British Columbia	☐	☐	☐	☐	☐
When something needs to be done around the home, I usually hire someone	☐	☐	☐	☐	☐
I almost always have some home renovation on the go	☐	☐	☐	☐	☐
There is an adequate supply of natural gas in British Columbia	☐	☐	☐	☐	☐

J2. On a scale of one to five, where one means that you strongly disagree and five means that you strongly agree, please indicate whether you agree or disagree with the following statements.

	Strongly disagree 1	2	Neither agree nor disagree 3	4	Strongly agree 5
I am usually the first one to try new products	☐	☐	☐	☐	☐
I am usually willing to pay more for brand name items	☐	☐	☐	☐	☐
I prefer dealing with BC-based companies	☐	☐	☐	☐	☐
When buying any products or services, I always look for the best price	☐	☐	☐	☐	☐
I prefer to use smaller, local companies rather than larger organizations	☐	☐	☐	☐	☐
When I make decisions, I usually take time to research issues thoroughly	☐	☐	☐	☐	☐
I'm the type of person to have good insurance coverage	☐	☐	☐	☐	☐

J3. How often do you do the following:

	Always	Usually	Occasionally	Never
Recycle newspaper, metals, plastics, or glass	☐	☐	☐	☐
Reduce energy use in the home	☐	☐	☐	☐
Use cloth / reusable grocery bags	☐	☐	☐	☐
Walk, ride a bike, carpool, or take public transit to help the environment	☐	☐	☐	☐
Donate time or money to environmental causes	☐	☐	☐	☐
Buy products that are environmentally friendly	☐	☐	☐	☐
Pay more for products that are environmentally friendly	☐	☐	☐	☐

J4. How knowledgeable would you say you are about ways to save energy?

- Very knowledgeable ☐
- Somewhat knowledgeable ☐
- Not too knowledgeable ☐
- Not at all knowledgeable ☐

K. DEMOGRAPHICS

The final questions are for classification purposes only and are completely confidential, as are all your answers.

K1. Into which of the following age categories do you fit?

- 18 years or under ☐
- 19-24 years ☐
- 25-34 years ☐
- 35-44 years ☐
- 45-54 years ☐
- 55-64 years ☐
- 65 years and older ☐

K2. What is your marital status?

- Single ☐
- Married/common law ☐
- Divorced/separated ☐
- Widowed ☐

K3. How many people, including yourself, are currently living in your household? Please include any boarders or renters who do not have a separate natural gas account.

_____ number

K4. Please indicate the number of occupants by age category:

	0	1	2	3	4	5	6+
18 years or under	☐	☐	☐	☐	☐	☐	☐
19-24 years	☐	☐	☐	☐	☐	☐	☐
25-34 years	☐	☐	☐	☐	☐	☐	☐
35-44 years	☐	☐	☐	☐	☐	☐	☐
★ 45-54 years	☐	☐	☐	☐	☐	☐	☐
55-64 years	☐	☐	☐	☐	☐	☐	☐
65 years and older	☐	☐	☐	☐	☐	☐	☐

K5. Has the number of people in your household changed in the last two years?

Yes ☐→ **GO TO QUESTION K6**
No ☐→ **GO TO QUESTION K7**

K6. How has your household size changed over the past two years (please check the best answer)?

- In the past there were more people in the household ☐
- In the past there were fewer people in the household ☐
- In the past there were sometimes more people and sometimes fewer people in the household ☐

K7. What is the highest level of education you have completed?

- Some high school ☐
- Completed high school ☐
- Some trade/technical school ☐
- Completed trade/technical school ☐
- ▲ Some university/college ☐
- Completed university/college ☐
- Post graduate ☐

K8. What was your total annual household income before taxes in 2007?

Less than $20,000	☐	$60,000 to $79,999	☐
$20,000 to $39,999	☐	$80,000 to $99,999	☐
$40,000 to $59,999	☐	$100,000 to $124,999	☐
		Over $125,000	☐

K9. Please indicate the main language spoken in your home (check one only) and all other languages spoken in your home. (check all that apply)

	Main language spoken in home (check one only)		Other languages spoken in home (check all that apply)	
English	☐		☐	
Mandarin	☐		☐	
Cantonese	☐		☐	
Other Chinese	☐		☐	
Punjabi	☐		☐	
Korean	☐		☐	
Tagalog	☐		☐	▲
Farsi (Persian)	☐		☐	
Vietnamese	☐		☐	
Spanish	☐		☐	
French	☐		☐	
German	☐		☐	
Hindi	☐		☐	
Other (please specify)	☐	____________	☐	____________

Terasen Gas and NRG Research would like to thank you for your help and assistance. If you have any questions please contact Scott Webb at (604) 592-7649 at Terasen Gas.

FOR OFFICE USE ONLY

Identification number:

Reminder Card

There's still time left

Complete the Terasen Gas Residential Survey sent to you earlier this month for a chance to win one of two **$500 gift certificates.** Please respond before December 5, 2008. Your input helps Terasen Gas understand how customers use energy in their homes. And that will help us meet the future energy needs of British Columbians.

Already completed your survey? Thank you.

Paper not your thing? **Complete your survey online** and **receive an additional chance to win a $500 gift certificate.** Go to www.nrgsurveys.ca/terasengas and enter the code that appears to the right of your address shown on the other side of this card.

Terasen Gas

terasengas.com

Appendix B

2008 REUS
Conditional Demand Analysis
Detailed Methodology

2008 REUS Conditional Demand Analysis Detailed Methodology

Conditional Demand Analysis (CDA) was used to disaggregate total household consumption into UECs for several residential end uses. CDA is based on the notion that total household consumption is directly related to the stock of end uses present in the dwelling and the energy consumption levels associated with these end uses (UECs). The basic conditional demand model can be represented as:

$$HEC_{ht} = \sum_{all\ a} UEC_{aht} S_{ah}$$

where HEC_{ht} is the total energy consumption by household *h* in month *t*, UEC_{aht} is the energy consumption through end use *a* by household *h* in month *t*, and S_{ah} is the presence or absence of end use *a* in household *h*.

The UECs for these end uses are modelled as functions of appropriate exogenous variables, such as end use features, dwelling characteristics and household utilization patterns. In the remainder of this section, we describe the functional forms for each end use.

B1. Primary Gas Space Heating

The primary gas space heating usage for household *h* in month *t* is based on a balance equation:

$$UEC_{gheat,ht} = \frac{HEATLOSS_{ht} - SECHT_{ht}}{EFFH_h}$$

where $HEATLOSS_{ht}$ is the net heat loss, $SECHT_{ht}$ is the heat loss replaced by non-gas secondary heating systems, and $EFFH_h$ is the system efficiency.

Net Heat Loss

The net heat loss of a structure can be expressed as:

$$HEATLOSS_{ht} = SURFLOSS_{ht} - SOLGAIN_{ht} - INTGAIN_{ht}$$

where $SURFLOSS_{ht}$ is the heat loss through envelope surfaces, $SOLGAIN_{ht}$ is the solar gain through all surfaces during heating periods, and $INTGAIN_{ht}$ is the internal gains during heating periods.

Heat Loss through Envelope

The heat loss through envelope surfaces is given by:

$$SURFLOSS_h = \alpha_1 U_h AREA_h TDIFF_{ht}$$

where U_h is the overall conductivity of the shell, $AREA_h$ is the total surface area, and $TDIFF_{ht}$ is the differential between inside and outside temperature levels.

Shell Conductivity

The conductivity of the shell is assumed to depend on residence type, the percentage of windows and doors that are insulated, and the level of basement insulation[35]:

$$U_h = \alpha_1 + \alpha_2 MFD_h + \alpha_3 VS_h + \alpha_4 WINDBL_h + \alpha_5 WINBEST_h + \alpha_6 DOORS_h + \alpha_7 BASEPRES_h BASEINSUL_h$$

where MFD_h equals one if the household dwelling is a multi-family dwelling, VS_h equals one if the dwelling is a vertical subdivision (apartment), $WINDBL_h$ is the percentage windows with double pane glass, and $WINBEST_h$ is the percentage of windows with more insulation than double pane (double pane low-E or triple pane, regular or low-E), $DOORS_h$ is the proportion of exterior doors that are insulated (aluminium storm doors or insulated exterior doors), $BASEPRES_h$ equals one if a basement is present, and $BASEINSUL_h$ equals one if the basement has average or better insulation (R > 6).

Surface Area

The surface area of the structure is modelled as a function of the total floor area:

$$AREA_h = \alpha_1 SQFT_h^{\beta}$$

where $SQFT_h$ is the square footage of the household and β is the elasticity of surface area with respect to square footage. We assumed that β equals 0.5 (i.e. the square root) because the surface area of the building shell increases less than proportionately with floor area for standard shaped buildings.

Temperature Differential

The differential between inside and outside temperature levels is modelled as a function of heating degree days and household heating behaviour (frequency of turning down the temperature at night or during the day when no one is home, and frequency of using window coverings to reduce heat loss in winter)[36]:

$$TDIFF_{ht} = HDD_{ht}\left(\alpha_1 + \alpha_2 TDNIGHT_h + \alpha_3 TDDAY_h + \alpha_4 WINTER_t WINCVR_h\right)$$

where HDD_{ht} is heating degree days, $TDNIGHT_h$ is the frequency of using a programmable thermostat or manual setback at night, $TDDAY_h$ is the frequency of using a programmable thermostat or manual setback during the day when no one is home, and $WINCVR_{ht}$ is the frequency of using window covers during winter.

Solar Gain

The solar gain through all surfaces during heating periods is modelled as a function of the surface area of the home and minutes of sunlight:

$$SOLGAIN_{ht} = \alpha_1 AREA_h WINTER_t HRSUN_{ht}$$

where $HRSUN_{ht}$ is hours of sunlight and $WINTER_t$ equals one if t is a winter month (December, January or February).

[35] An attempt was made to include variables involving wall and ceiling insulation levels. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.
[36] An attempt was made to include a variable representing the frequency of opening windows during the winter to let in fresh air. This variable was not retained in the final model because it was not statistically significant.

Internal Gain

The internal gain during heating periods is modelled as a function of the surface area of the home:

$$INTGAIN_{ht} = \alpha_1 AREA_h WINTER_t$$

Non-gas Secondary Heating System

The heat loss replaced by a non-gas secondary heating system, given that a primary gas heating system is present, can be expressed as:

$$SECHT_{ht} = \alpha_1 NONGASHEAT_h HDD_{ht} AREA_h$$

where $NONGASHEAT_h$ equals one if non-gas secondary heat is present (e.g. non-gas fireplace, woodstove, electric baseboards, etc.)

System Efficiency

System efficiencies are modelled indirectly in terms of the efficiency level of the boiler or furnace[37]:

$$1/EFFH_h = \alpha_1 + \alpha_2 MIDEFF_h + \alpha_3 HIGHEFF_h$$

where $MIDEFF_h$ equals one if a mid efficiency furnace is in use, and $HIGHEFF_h$ equals one if a high efficiency boiler or furnace is in use.

Overall Primary Gas Space Heating Model

Combining the preceding equations gives the overall model of primary gas space heating usage:

$$UEC_{gheat,ht} = \begin{cases} HDD_{ht} AREA_h (\alpha_1 + \alpha_2 MFD_h + \alpha_3 VS_h + \alpha_4 WINDBL_h + \alpha_5 WINBEST_h \\ + \alpha_6 DOORS_h + \alpha_7 BASEPRES_h BASEIN + \alpha_8 TDNIGHT_h + \alpha_9 TDDAY_h \\ + \alpha_{10} WINTER_t WINCVR_h + \alpha_{11} MIDEFF_h + \alpha_{12} HIGHEFF_h + \alpha_{13} NONGASHEAT_h) \\ + \alpha_{14} AREA_h WINTER_t HRSUN_{ht} + \alpha_{15} AREA_h WINTER_t \end{cases}$$

In the specification above, most of the interaction terms are not shown because they were not statistically significant or produced unreasonable results.

B2. Secondary Gas Space Heating

Secondary gas space heating includes any additional or supplementary use of gas to heat the residence (e.g., furnaces, gas wall heaters, gas heating stoves, etc.) The use of gas fireplaces is modelled separately.

The secondary gas space heating usage is modelled simply as a function of heating degree days, total surface area and dwelling type:

$$UEC_{\sec ght,ht} = HDD_{ht} AREA_h (\alpha_1 + \alpha_2 MFD_h + \alpha_3 VS_h)$$

---

[37] An attempt was made to include a variable for whether or not the furnace pilot light is turned off during the year. This variable was not retained in the final model because it was not statistically significant.

B3. Fireplaces

The energy usage by gas fireplaces (decorative and heater type) is assumed to depend on the number of fireplaces in use[38]:

$$UEC_{decgasfire,ht} = \alpha_1 DECGASFIRE_h$$
$$UEC_{heatgasfire,ht} = \alpha_1 HEATGASFIRE_h$$

where $DECGASFIRE_h$ is the number of declarative fire places and $HEATGASFIRE_h$ is the number of heater type gas fire places.

B4. Water Heating

Gas water heating energy usage can be expressed as:

$$UEC_{gwheat,ht} = \frac{WHLOSS_{ht} + VUSE_{ht}}{EFFWH_h}$$

where $WHLOSS_{ht}$ is the heat losses associated with standby losses from the heating unit, $VUSE_{ht}$ is the heat losses tied to water usage, and $EFFWH_h$ is the efficiency of the unit.

Standby Losses

The heat losses associated with standby losses is assumed to depend on the temperature differential between the tank temperature and the inlet temperature[39]:

$$WHLOSS_{ht} = \alpha_1 WHTDIFF_{ht}$$

where $WHTDIFF_{ht}$ is the differential between the tank temperature and the inlet temperature. The differential between tank temperature and inlet temperature is modelled simply as a function of heating degree days:

$$WHTDIFF_{ht} = \alpha_1 HDD_{ht}$$

Water Usage

The heat losses tied to water usage is assumed to depend on the average number of baths and showers taken, the proportion of low-flow showerheads, and whether or not a front loading clothes washer is present[40]:

$$VUSE_{ht} = \alpha_1 + \alpha_2 BATHS_h + \alpha_3 SHWRS_h + \alpha_4 LOWFLPROP_h + \alpha_5 CWFLD_h$$

[38] An attempt was made to include variables representing if the fireplaces are used primarily for heating, ambiance or both. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.

[39] An attempt was made to include variables involving the dwelling type, number of household members (a proxy for tank size), and the presence or absence of water heater blankets. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.

[40] An attempt was made to include variables involving household size, as well as the average number of dishwasher loads and washing machine loads. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.

where $BATHS_h$ is the number of baths taken per week, $SHWRS_h$ is the number of showers taken per week, $LOWFLPROP_h$ is the proportion of low-flow showerheads, and $CWFLD_h$ equals one if a front loading clothes washer is used.

System Efficiency

An attempt was made to model system efficiencies in terms of the age of the water heater, however, the results were not statistically significant. Therefore, we assumed that $EFFWH_h$ is constant across households.

Overall Water Heating Model

Combining the preceding equations gives the overall model for gas water heating energy usage:

$$UEC_{gwheat,ht} = \alpha_1 HDD_{ht} + \alpha_2 BATHS_h + \alpha_3 SHWRS_h + \alpha_4 LOWFLPROP_h + \alpha_5 CWFLD_h$$

B5. Gas Ranges, Cook Tops and Ovens

Energy consumption of gas ranges, cook tops and ovens is assumed to depend on the number of these appliances in use[41]:

$$UEC_{gasrange,ht} = \alpha_1 GASRANGE_h$$

where $GASRANGE_h$ is the number of gas ranges, cook tops and ovens in use.

B6. Gas BBQs

Energy consumption of gas BBQs is modelled as a function of the number in use[42]:

$$UEC_{BBQ,ht} = \alpha_1 GASBBQ_h$$

where $GASBBQ_h$ is the number of gas barbeques in use.

B7. Gas Dryers

Energy consumption of gas dryers is modelled as a function of the number in use[43]:

$$UEC_{Dryer,ht} = \alpha_1 GASDRYER_h$$

where $GASDRYER_h$ is the number of gas dryers in use.

B8. Swimming Pools

Energy consumption through the operation of swimming pools is assumed to be constant for those households with gas-heated swimming pools[44]:

[41] An attempt was made to include variables involving household size, income and the presence of a microwave. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.

[42] An attempt was made to include a variable involving household size. This variable was not retained in the final model because it was not statistically significant.

[43] An attempt was made to include a variable involving household size and the number of washing machine loads. These variables were not retained in the final model because they were not statistically significant.

$$UEC_{Swimpoolgas,ht} = \alpha_1$$

B9. Hot Tubs

Energy consumption through the operation of hot tubs is assumed to be constant for those households with gas-heated hot tubs[45]:

$$UEC_{hottubgas,ht} = \alpha_1$$

B10. Regional Analysis

Regional variations in the CDA were explored by fitting separate models for each of the five key regions: Lower Mainland, Interior, Vancouver Island, Whistler and Fort Nelson. However, small sample sizes for many of the regions, combined with low penetration rates for many of the end uses, led to large variation and uncertainty in the UEC estimates across regions. To ensure more robust results, it was decided to incorporate regional terms into a single overall model instead of using separate regional models. With this approach, the model was able to capture regional variation in UECs for key end uses like space heating, but assumed constant UECs for most other end uses.

B11. Regression Output Summary

Exhibit B1 summarizes the regression outputs from the CDA model.

Exhibit B1: Regression Output

	Coefficient	Standard Error	t-value	P-value
LM x AREA x HDD x S_{gheat}	0.001300	0.000009	152.4	0.000
VI x AREA x HDD x S_{gheat}	0.001035	0.000012	86.1	0.000
IN x AREA x HDD x S_{gheat}	0.000819	0.000009	93.2	0.000
WH x AREA x HDD x S_{gheat}	0.000958	0.000041	23.3	0.000
FN x AREA x HDD x S_{gheat}	0.000870	0.000017	50.7	0.000
LM x MFD x AREA x HDD x S_{gheat}	-0.000414	0.000012	-34.0	0.000
LM x VS x AREA x HDD x S_{gheat}	-0.000899	0.000063	-14.2	0.000
VI x MFD x AREA x HDD x S_{gheat}	-0.000354	0.000049	-7.2	0.000
IN x MFD x AREA x HDD x S_{gheat}	-0.000152	0.000016	-9.4	0.000
IN x VS x AREA x HDD x S_{gheat}	-0.000412	0.000094	-4.4	0.000
WH x MFD x AREA x HDD x S_{gheat}	-0.000321	0.000093	-3.5	0.001
AREA x HDD x TDNIGHT x S_{gheat}	-0.000044	0.000007	-6.4	0.000
AREA x HDD x TDDAY x S_{gheat}	-0.000116	0.000006	-18.9	0.000
AREA x HDD x WINTER x WINCVR x S_{gheat}	-0.000006	0.000006	-1.0	0.317
AREA x HDD x MIDEFF x S_{gheat}	-0.000045	0.000004	-10.1	0.000
AREA x HDD x HIGHEFF x S_{gheat}	-0.000152	0.000005	-29.3	0.000
AREA x HDD x WINDBL x S_{gheat}	-0.000086	0.000005	-15.7	0.000
AREA x HDD x WINBEST x S_{gheat}	-0.000115	0.000007	-16.7	0.000
AREA x HDD x DOORS x S_{gheat}	-0.000086	0.000005	-16.2	0.000
AREA x HDD x BASEPRES x BASEINSUL x S_{gheat}	-0.000041	0.000004	-10.7	0.000

…exhibit continued next page

[44] An attempt was made to include variables for whether or not the pool is covered when not in use and whether or not solar supplementary heating is used. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.

[45] An attempt was made to include a variable for whether or not the hot tub is covered when not in use. This variable was not retained in the final model because it was not statistically significant.

Exhibit B1: Regression Output - Continued

	Coefficient	Standard Error	t-value	P-value
AREA x WINTER x HRSUN x S_{gheat}	-0.000449	0.000044	-10.1	0.000
AREA x WINTER x S_{gheat}	0.026443	0.002614	10.1	0.000
HDD x AREA x NONGASHEAT x S_{gheat}	-0.000065	0.000004	-17.6	0.000
HDD x AREA x S_{secght}	0.000338	0.000008	43.6	0.000
HDD x AREA x MFD x S_{secght}	-0.000150	0.000030	-5.0	0.000
HDD x AREA x VS x S_{secght}	-0.000280	0.000083	-3.4	0.001
DECGASFIRE x $S_{decgasfire}$	1.381636	0.032368	42.7	0.000
HEATGASFIRE x $S_{heatgasfire}$	1.071822	0.022930	46.7	0.000
HDD x S_{gwheat}	0.000577	0.000232	2.5	0.013
BATHS x S_{gwheat}	0.211052	0.005681	37.1	0.000
SHWRS x S_{gwheat}	0.110918	0.002027	54.7	0.000
LOWFLPROP x S_{gwheat}	-0.019552	0.038940	-0.5	0.616
CWFLD x S_{gwheat}	-0.459419	0.042375	-10.8	0.000
GASRANGE x $S_{gasrange}$	0.310153	0.025780	12.0	0.000
GASBBQ x S_{bbq}	0.659416	0.047388	13.9	0.000
GASDRYER x S_{dryer}	0.278914	0.060137	4.6	0.000
$S_{swimpool}$	3.212457	0.115210	27.9	0.000
$S_{hottubgas}$	1.628916	0.123136	13.2	0.000

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Coastal Region
YE Accounts by Rate Class

Core	2010	2011	2012	2013	2014	2015	2016	2017	2018
Rate 1	528,119	531,685	534,987	538,473	541,959	545,472	549,001	552,082	555,041
Rate 2	53,672	54,110	54,558	55,021	55,484	55,954	56,430	56,829	57,207
Rate 3	4,104	4,173	4,242	4,305	4,376	4,447	4,518	4,582	4,641
Rate 4	33	33	33	33	33	33	33	33	33
Rate 5	221	221	221	221	221	221	221	221	221
Rate 6	26	26	26	26	26	26	26	26	26
Total Coastal Region-Core	586,175	590,248	594,067	598,079	602,099	606,153	610,229	613,773	617,169
Transportation & IT Customers									
Rate 7	1	1	1	1	1	1	1	1	1
Rate 22	22	22	22	22	22	22	22	22	22
Rate 23	1,116	1,121	1,126	1,131	1,136	1,141	1,146	1,148	1,149
Rate 25	488	488	488	488	488	488	488	488	488
Rate 27	81	81	81	81	81	81	81	81	81
Total -Transportation & IT	1,708	1,713	1,718	1,723	1,728	1,733	1,738	1,740	1,741
Total Coastal Region	587,883	591,961	595,785	599,802	603,827	607,886	611,967	615,513	618,910

Percent change in YE Accounts

Core	2010	2011	2012	2013	2014	2015	2016	2017	2018
Rate 1		0.68%	0.62%	0.65%	0.65%	0.65%	0.65%	0.56%	0.54%
Rate 2		0.82%	0.83%	0.85%	0.84%	0.85%	0.85%	0.71%	0.67%
Rate 3		1.68%	1.65%	1.49%	1.65%	1.62%	1.60%	1.42%	1.29%
Rate 4		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 5		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 6		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transportation & IT Customers									
Rate 7		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 22		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 23		0.45%	0.45%	0.44%	0.44%	0.44%	0.44%	0.17%	0.09%
Rate 25		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 27		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Core	2010	2011	2012	2013	2014	2015	2016	2017	2018
Rate 1	98	97	95	94	93	92	91	90	90
Rate 2	335	334	334	333	332	332	331	330	330
Rate 3	3,276	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243
Rate 4	2,303	2,303	2,303	2,303	2,303	2,303	2,303	2,303	2,303
Rate 5	10,630	10,518	10,407	10,297	10,188	10,092	9,997	9,903	9,809
Rate 6	2,615	2,615	2,615	2,615	2,615	2,615	2,615	2,615	2,615
Transportation & IT Customers									
Rate 7	2,850	2,821	2,793	2,765	2,738	2,710	2,683	2,656	2,630
Rate 22	628,051	618,816	609,617	600,454	591,325	587,871	584,451	581,066	577,714
Rate 23	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865
Rate 25	17,904	17,672	17,440	17,210	16,981	16,866	16,752	16,640	16,528
Rate 27	59,348	58,737	58,128	57,523	56,920	56,651	56,385	56,122	55,861

Annual Demand by Rate Class(TJ)

Core	2010	2011	2012	2013	2014	2015	2016	2017	2018
Rate 1	51,935	51,403	50,929	50,560	50,280	50,093	49,999	49,960	50,006
Rate 2	17,980	18,073	18,222	18,322	18,421	18,577	18,678	18,754	18,878
Rate 3	13,445	13,533	13,757	13,961	14,191	14,422	14,652	14,859	15,051
Rate 4	76	76	76	76	76	76	76	76	76
Rate 5	2,349	2,325	2,300	2,276	2,252	2,230	2,209	2,188	2,168
Rate 6	68	68	68	68	68	68	68	68	68
Total Coastal Region-Core	85,854	85,477	85,352	85,263	85,288	85,466	85,683	85,905	86,246
Transportation & IT Customers									
Rate 7	3	3	3	3	3	3	3	3	3
Rate 22	13,817	13,614	13,412	13,210	13,009	12,933	12,858	12,783	12,710
Rate 23	5,429	5,454	5,478	5,502	5,527	5,551	5,575	5,585	5,590
Rate 25	8,737	8,624	8,511	8,399	8,287	8,231	8,175	8,120	8,066
Rate 27	4,807	4,758	4,708	4,659	4,611	4,589	4,567	4,546	4,525
Total Coastal Region-Transportation & IT	32,794	32,452	32,112	31,773	31,436	31,306	31,178	31,037	30,893
Total Coastal Region	**118,647**	**117,929**	**117,464**	**117,036**	**116,724**	**116,772**	**116,861**	**116,942**	**117,139**

Design Day Demand(TJ/Day)

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Core Customers	925.6	933.1	940.4	947.8	955.4	963.1	970.8	977.6	984.0

Coastal Region
YE Accounts by Rate Class

Core	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate 1	557,952	560,779	563,553	566,249	568,930	571,518	574,086	576,607	579,101
Rate 2	57,574	57,929	58,277	58,608	58,939	59,251	59,563	59,871	60,175
Rate 3	4,699	4,756	4,813	4,867	4,921	4,975	5,029	5,082	5,134
Rate 4	33	33	33	33	33	33	33	33	33
Rate 5	221	221	221	221	221	221	221	221	221
Rate 6	26	26	26	26	26	26	26	26	26
Total Coastal Region-Core	620,505	623,744	626,923	630,004	633,070	636,024	638,958	641,840	644,690
Transportation & IT Customers									
Rate 7	1	1	1	1	1	1	1	1	1
Rate 22	22	22	22	22	22	22	22	22	22
Rate 23	1,150	1,151	1,152	1,153	1,154	1,155	1,156	1,157	1,158
Rate 25	488	488	488	488	488	488	488	488	488
Rate 27	81	81	81	81	81	81	81	81	81
Total -Transportation & IT	1,742	1,743	1,744	1,745	1,746	1,747	1,748	1,749	1,750
Total Coastal Region	622,247	625,487	628,667	631,749	634,816	637,771	640,706	643,589	646,440

Percent change in YE Accounts

Core	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate 1	0.52%	0.51%	0.49%	0.48%	0.47%	0.45%	0.45%	0.44%	0.43%
Rate 2	0.64%	0.62%	0.60%	0.57%	0.56%	0.53%	0.53%	0.52%	0.51%
Rate 3	1.25%	1.21%	1.20%	1.12%	1.11%	1.10%	1.09%	1.05%	1.02%
Rate 4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transportation & IT Customers									
Rate 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 22	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 23	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%
Rate 25	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 27	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Core	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate 1	90	89	89	88	88	88	87	87	86
Rate 2	329	328	328	327	326	326	325	324	324
Rate 3	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243
Rate 4	2,303	2,303	2,303	2,303	2,303	2,303	2,303	2,303	2,303
Rate 5	9,717	9,625	9,535	9,445	9,356	9,268	9,181	9,095	9,010
Rate 6	2,615	2,615	2,615	2,615	2,615	2,615	2,615	2,615	2,615
Transportation & IT Customers									
Rate 7	2,603	2,577	2,552	2,526	2,501	2,476	2,451	2,426	2,402
Rate 22	574,396	571,110	567,858	564,638	561,451	558,295	555,171	552,078	549,016
Rate 23	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865
Rate 25	16,418	16,308	16,200	16,093	15,987	15,882	15,778	15,675	15,573
Rate 27	55,603	55,347	55,094	54,843	54,595	54,349	54,106	53,866	53,627

Annual Demand by Rate Class(TJ)

Core	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate 1	50,045	50,074	50,096	50,109	50,119	50,118	50,114	50,103	50,088
Rate 2	18,942	19,001	19,115	19,165	19,214	19,316	19,358	19,398	19,497
Rate 3	15,239	15,424	15,609	15,784	15,959	16,134	16,309	16,481	16,650
Rate 4	76	76	76	76	76	76	76	76	76
Rate 5	2,147	2,127	2,107	2,087	2,068	2,048	2,029	2,010	1,991
Rate 6	68	68	68	68	68	68	68	68	68
Total Coastal Region-Core	86,517	86,769	87,071	87,289	87,504	87,760	87,954	88,137	88,370
Transportation & IT Customers									
Rate 7	3	3	3	3	3	2	2	2	2
Rate 22	12,637	12,564	12,493	12,422	12,352	12,282	12,214	12,146	12,078
Rate 23	5,595	5,600	5,604	5,609	5,614	5,619	5,624	5,629	5,634
Rate 25	8,012	7,958	7,906	7,853	7,802	7,750	7,700	7,649	7,600
Rate 27	4,504	4,483	4,463	4,442	4,422	4,402	4,383	4,363	4,344
Total Coastal Region-Transportation & IT	30,750	30,608	30,468	30,330	30,192	30,057	29,922	29,789	29,658
Total Coastal Region	**117,266**	**117,378**	**117,539**	**117,619**	**117,696**	**117,817**	**117,876**	**117,926**	**118,028**

Design Day Demand(TJ/Day)

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Core Customers	990.3	996.4	1,002.5	1,008.3	1,014.1	1,019.7	1,025.4	1,030.9	1,036.3

Coastal Region
YE Accounts by Rate Class

Core	2028	2029	2030
Rate 1	581,568	584,022	586,447
Rate 2	60,476	60,774	61,070
Rate 3	5,188	5,243	5,296
Rate 4	33	33	33
Rate 5	221	221	221
Rate 6	26	26	26
Total Coastal Region-Core	647,512	650,319	653,093
Transportation & IT Customers			
Rate 7	1	1	1
Rate 22	22	22	22
Rate 23	1,159	1,160	1,161
Rate 25	488	488	488
Rate 27	81	81	81
Total -Transportation & IT	1,751	1,752	1,753
Total Coastal Region	649,263	652,071	654,846

Percent change in YE Accounts

Core	2028	2029	2030
Rate 1	0.43%	0.42%	0.42%
Rate 2	0.50%	0.49%	0.49%
Rate 3	1.05%	1.06%	1.01%
Rate 4	0.00%	0.00%	0.00%
Rate 5	0.00%	0.00%	0.00%
Rate 6	0.00%	0.00%	0.00%
Transportation & IT Customers			
Rate 7	0.00%	0.00%	0.00%
Rate 22	0.00%	0.00%	0.00%
Rate 23	0.09%	0.09%	0.09%
Rate 25	0.00%	0.00%	0.00%
Rate 27	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Core	2028	2029	2030
Rate 1	86	86	85
Rate 2	323	323	322
Rate 3	3,243	3,243	3,243
Rate 4	2,303	2,303	2,303
Rate 5	8,926	8,842	8,759
Rate 6	2,615	2,615	2,615
Transportation & IT Customers			
Rate 7	2,378	2,354	2,331
Rate 22	545,985	542,984	540,013
Rate 23	4,865	4,865	4,865
Rate 25	15,472	15,372	15,273
Rate 27	53,391	53,158	52,926

Annual Demand by Rate Class(TJ)

Core	2028	2029	2030
Rate 1	50,069	50,047	50,020
Rate 2	19,534	19,630	19,665
Rate 3	16,825	17,003	17,175
Rate 4	76	76	76
Rate 5	1,973	1,954	1,936
Rate 6	68	68	68
Total Coastal Region-Core	88,544	88,778	88,939
Transportation & IT Customers			
Rate 7	2	2	2
Rate 22	12,012	11,946	11,880
Rate 23	5,639	5,643	5,648
Rate 25	7,550	7,502	7,453
Rate 27	4,325	4,306	4,287
Total Coastal Region-Transportation & IT	29,528	29,399	29,271
Total Coastal Region	**118,072**	**118,177**	**118,211**

Design Day Demand(TJ/Day)

	2028	2029	2030
Core Customers	1,041.8	1,047.3	1,052.8

Interior Region
YE Accounts by Rate Class

Core	2010	2011	2012	2013	2014	2015	2016	2017
Rate 1	232,073	234,525	236,928	239,396	241,863	244,408	246,992	249,056
Rate 2	23,134	23,380	23,631	23,890	24,149	24,418	24,687	24,903
Rate 3	845	877	910	944	978	1,014	1,051	1,082
Rate 4	12	12	12	12	12	12	12	12
Rate 5	32	32	32	32	32	32	32	32
Rate 6	2	2	2	2	2	2	2	2
Total Coastal Region-Core	256098	258828	261515	264276	267036	269886	272776	275087
Transportation & IT Customers								
Rate 7	2	2	2	2	2	2	2	2
Rate 22	9	24	24	24	24	24	24	24
Rate 23	241	245	249	253	257	261	265	268
Rate 25	95	95	95	95	95	95	95	95
Rate 27	16	16	16	16	16	16	16	16
Total -Transportation & IT	363	382	386	390	394	398	402	405
Total Interior Region	**256461**	**259210**	**261901**	**264666**	**267430**	**270284**	**273178**	**275492**

Percent change in YE Accounts

Core	2010	2011	2012	2013	2014	2015	2016	2017
Rate 1		1.06%	1.02%	1.04%	1.03%	1.05%	1.06%	0.84%
Rate 2		1.06%	1.07%	1.10%	1.08%	1.11%	1.10%	0.87%
Rate 3		3.79%	3.76%	3.74%	3.60%	3.68%	3.65%	2.95%
Rate 4		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 5		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 6		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation & IT Customers								
Rate 7		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 22		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 23		1.66%	1.63%	1.61%	1.58%	1.56%	1.53%	1.13%
Rate 25								
Rate 27		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer by Rate Class(GJ)

Core	2010	2011	2012	2013	2014	2015	2016	2017
Rate 1	76	74	73	71	70	69	68	68
Rate 2	288	287	287	286	286	285	285	283
Rate 3	3,372	3,338	3,338	3,338	3,338	3,338	3,338	3,338
Rate 4	9,583	9,583	9,583	9,583	9,583	9,583	9,583	9,583
Rate 5	13,152	13,021	12,892	12,764	12,637	12,519	12,401	12,284
Rate 6	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Transportation & IT Customers								
Rate 7	1,897	1,878	1,859	1,841	1,822	1,804	1,786	1,768
Rate 22	1,585,924	563,301	531,882	500,464	469,048	468,929	468,812	468,696
Rate 23	5,362	5,363	5,364	5,365	5,366	5,367	5,368	5,368
Rate 25	35,516	35,278	35,042	34,807	34,572	34,447	34,322	34,199
Rate 27	42,324	41,651	40,980	40,311	39,643	39,468	39,295	39,124

Annual Demand by Rate Class(TJ)

Core	2010	2011	2012	2013	2014	2015	2016	2017
Rate 1	17,641	17,406	17,205	17,049	16,935	16,868	16,848	16,839
Rate 2	6,660	6,706	6,775	6,827	6,897	6,949	7,024	7,060
Rate 3	2,849	2,928	3,038	3,151	3,265	3,385	3,508	3,611
Rate 4	115	115	115	115	115	115	115	115
Rate 5	421	417	413	408	404	401	397	393
Rate 6	7	7	7	7	7	7	7	7
Total Coastal Region-Core	27,692	27,578	27,552	27,558	27,623	27,724	27,899	28,025
Transportation & IT Customers								
Rate 7	4	4	4	4	4	4	4	4
Rate 22	14,273	13,519	12,765	12,011	11,257	11,254	11,251	11,249
Rate 23	1,292	1,314	1,336	1,357	1,379	1,401	1,422	1,439
Rate 25	3,374	3,351	3,329	3,307	3,284	3,272	3,261	3,249
Rate 27	677	666	656	645	634	631	629	626
Total Interior Region-Transportation & IT	19,621	18,855	18,089	17,324	16,559	16,563	16,567	16,566
Total Interior Region	**47,313**	**46,433**	**45,642**	**44,881**	**44,181**	**44,287**	**44,466**	**44,591**

Design Day Demand(TJ/Day)

	2010	2011	2012	2013	2014	2015	2016	2017
Core Customers	335.0	339.4	343.7	348.2	352.7	357.4	362.1	366.0

Interior Region
YE Accounts by Rate Class

Core	2018	2019	2020	2021	2022	2023	2024	2025
Rate 1	251,010	252,862	254,639	256,333	257,973	259,630	261,239	262,792
Rate 2	25,108	25,300	25,484	25,654	25,817	25,980	26,136	26,289
Rate 3	1,113	1,142	1,169	1,196	1,224	1,253	1,282	1,312
Rate 4	12	12	12	12	12	12	12	12
Rate 5	32	32	32	32	32	32	32	32
Rate 6	2	2	2	2	2	2	2	2
Total Coastal Region-Core	277277	279350	281338	283229	285060	286909	288703	290439
Transportation & IT Customers								
Rate 7	2	2	2	2	2	2	2	2
Rate 22	24	24	24	24	24	24	24	24
Rate 23	271	274	277	280	283	286	289	292
Rate 25	95	95	95	95	95	95	95	95
Rate 27	16	16	16	16	16	16	16	16
Total -Transportation & IT	408	411	414	417	420	423	426	429
Total Interior Region	**277685**	**279761**	**281752**	**283646**	**285480**	**287332**	**289129**	**290868**

Percent change in YE Accounts

Core	2018	2019	2020	2021	2022	2023	2024	2025
Rate 1	0.78%	0.74%	0.70%	0.67%	0.64%	0.64%	0.62%	0.59%
Rate 2	0.82%	0.76%	0.73%	0.67%	0.64%	0.63%	0.60%	0.59%
Rate 3	2.87%	2.61%	2.36%	2.31%	2.34%	2.37%	2.31%	2.34%
Rate 4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation & IT Customers								
Rate 7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 23	1.12%	1.11%	1.09%	1.08%	1.07%	1.06%	1.05%	1.04%
Rate 25								
Rate 27	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer by Rate Class(GJ)

Core	2018	2019	2020	2021	2022	2023	2024	2025
Rate 1	67	67	66	66	66	65	65	64
Rate 2	283	282	281	281	280	280	279	279
Rate 3	3,338	3,338	3,338	3,337	3,337	3,337	3,337	3,337
Rate 4	9,583	9,583	9,583	9,583	9,583	9,583	9,583	9,583
Rate 5	12,169	12,055	11,942	11,830	11,719	11,609	11,501	11,393
Rate 6	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Transportation & IT Customers								
Rate 7	1,750	1,733	1,716	1,698	1,681	1,665	1,648	1,631
Rate 22	468,582	468,468	468,356	468,244	468,134	468,025	467,917	467,810
Rate 23	5,369	5,370	5,370	5,371	5,371	5,372	5,372	5,373
Rate 25	34,077	33,957	33,837	33,719	33,602	33,486	33,371	33,257
Rate 27	38,955	38,787	38,621	38,456	38,294	38,132	37,973	37,815

Annual Demand by Rate Class(TJ)

Core	2018	2019	2020	2021	2022	2023	2024	2025
Rate 1	16,870	16,893	16,909	16,919	16,923	16,927	16,927	16,922
Rate 2	7,117	7,146	7,172	7,219	7,238	7,281	7,300	7,339
Rate 3	3,715	3,812	3,902	3,992	4,085	4,181	4,278	4,378
Rate 4	115	115	115	115	115	115	115	115
Rate 5	389	386	382	379	375	372	368	365
Rate 6	7	7	7	7	7	7	7	7
Total Coastal Region-Core	28,214	28,358	28,487	28,630	28,743	28,883	28,995	29,126
Transportation & IT Customers								
Rate 7	4	3	3	3	3	3	3	3
Rate 22	11,246	11,243	11,241	11,238	11,235	11,233	11,230	11,227
Rate 23	1,455	1,471	1,488	1,504	1,520	1,536	1,553	1,569
Rate 25	3,237	3,226	3,215	3,203	3,192	3,181	3,170	3,159
Rate 27	623	621	618	615	613	610	608	605
Total Interior Region-Transportation & IT	16,565	16,564	16,564	16,564	16,564	16,564	16,564	16,564
Total Interior Region	**44,779**	**44,922**	**45,051**	**45,193**	**45,307**	**45,446**	**45,559**	**45,690**

Design Day Demand(TJ/Day)

	2018	2019	2020	2021	2022	2023	2024	2025
Core Customers	369.7	373.2	376.5	379.7	382.9	386.1	389.2	392.4

Interior Region
YE Accounts by Rate Class

Core	2026	2027	2028	2029	2030
Rate 1	264,320	265,838	267,249	268,690	270,132
Rate 2	26,441	26,590	26,719	26854	26989
Rate 3	1,340	1,368	1,396	1424	1452
Rate 4	12	12	12	12	12
Rate 5	32	32	32	32	32
Rate 6	2	2	2	2	2
Total Coastal Region-Core	292147	293842	295410	297014	298619
Transportation & IT Customers					
Rate 7	2	2	2	2	2
Rate 22	24	24	24	24	24
Rate 23	295	298	300	303	306
Rate 25	95	95	95	95	95
Rate 27	16	16	16	16	16
Total -Transportation & IT	432	435	437	440	443
Total Interior Region	**292579**	**294277**	**295847**	**297454**	**299062**

Percent change in YE Accounts

Core	2026	2027	2028	2029	2030
Rate 1	0.58%	0.57%	0.53%	0.54%	0.54%
Rate 2	0.58%	0.56%	0.49%	0.51%	0.50%
Rate 3	2.13%	2.09%	2.05%	2.01%	1.97%
Rate 4	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 5	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 6	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation & IT Customers					
Rate 7	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 22	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 23	1.03%	1.02%	0.67%	1.00%	0.99%
Rate 25					
Rate 27	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer by Rate Class(GJ)

Core	2026	2027	2028	2029	2030
Rate 1	64	64	63	63	62
Rate 2	278	278	277	277	276
Rate 3	3,337	3,337	3,336	3,336	3,335
Rate 4	9,583	9,583	9,583	9,583	9,583
Rate 5	11,287	11,181	11,077	10,974	10,872
Rate 6	3,500	3,500	3,500	3,500	3,500
Transportation & IT Customers					
Rate 7	1,615	1,599	1,583	1,567	1,551
Rate 22	467,704	467,599	467,495	467,393	467,291
Rate 23	5,374	5,374	5,374	5,375	5,375
Rate 25	33,145	33,033	32,923	32,814	32,706
Rate 27	37,659	37,504	37,350	37,199	37,049

Annual Demand by Rate Class(TJ)

Core	2026	2027	2028	2029	2030
Rate 1	16,915	16,905	16,887	16,870	16,852
Rate 2	7,358	7,395	7,404	7,440	7,449
Rate 3	4,471	4,564	4,657	4,750	4,843
Rate 4	115	115	115	115	115
Rate 5	361	358	354	351	348
Rate 6	7	7	7	7	7
Total Coastal Region-Core	29,227	29,345	29,425	29,534	29,614
Transportation & IT Customers					
Rate 7	3	3	3	3	3
Rate 22	11,225	11,222	11,220	11,217	11,215
Rate 23	1,585	1,601	1,612	1,629	1,645
Rate 25	3,149	3,138	3,128	3,117	3,107
Rate 27	603	600	598	595	593
Total Interior Region-Transportation & IT	16,565	16,565	16,561	16,562	16,563
Total Interior Region	**45,791**	**45,910**	**45,986**	**46,095**	**46,177**

Design Day Demand(TJ/Day)

	2026	2027	2028	2029	2030
Core Customers	395.4	398.4	401.2	404.1	407.1

TGVI

TGVI Year end accounts by Rate Class

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
RGS	90,926	93,631	96,379	99,199	102,086	105,095	108,187	110,640
SCS1	5168	5275	5384	5496	5611	5731	5855	5950
SCS2	1420	1425	1430	1435	1440	1446	1452	1455
LCS1	1365	1370	1375	1380	1385	1390	1396	1399
LCS2	531	536	541	546	551	557	563	567
AGS	881	886	891	896	901	906	911	915
LCS3	125	128	131	134	137	140	143	146
HLF	6	6	6	6	6	6	6	6
ILF	8	8	8	8	8	8	8	8
Total	**100,430**	**103,265**	**106,145**	**109,100**	**112,125**	**115,279**	**118,521**	**121,086**

Percent change in Year end Accounts by Rate Class

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
RGS		2.97%	2.93%	2.93%	2.91%	2.95%	2.94%	2.27%
SCS1		2.07%	2.07%	2.08%	2.09%	2.14%	2.16%	1.62%
SCS2		0.35%	0.35%	0.35%	0.35%	0.42%	0.41%	0.21%
LCS1		0.37%	0.36%	0.36%	0.36%	0.36%	0.43%	0.21%
LCS2		0.94%	0.93%	0.92%	0.92%	1.09%	1.08%	0.71%
AGS		0.57%	0.56%	0.56%	0.56%	0.55%	0.55%	0.44%
LCS3		2.40%	2.34%	2.29%	2.24%	2.19%	2.14%	2.10%
HLF		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ILF		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
RGS	52	50	48	47	46	45	44	43
SCS1	116	116	116	116	116	116	116	116
SCS2	325	325	325	325	325	325	325	325
LCS1	980	980	980	980	980	980	980	980
LCS2	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481
AGS	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259
LCS3	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911
HLF	19,585	19,585	19,585	19,585	19,585	19,585	19,585	19,585
ILF	12,197	12,197	12,197	12,197	12,197	12,197	12,197	12,197

Annual Demand by Rate Class(TJ)

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
RGS	4,686	4,657	4,639	4,636	4,648	4,680	4,731	4,772
SCS1	602	614	627	640	653	667	682	693
SCS2	462	463	465	466	468	470	472	473
LCS1	1,337	1,342	1,347	1,352	1,357	1,362	1,368	1,371
LCS2	1,318	1,330	1,342	1,355	1,367	1,382	1,397	1,407
AGS	1,109	1,115	1,122	1,128	1,134	1,141	1,147	1,152
LCS3	1,864	1,909	1,953	1,998	2,043	2,087	2,132	2,177
HLF	118	118	118	118	118	118	118	118
ILF	98	98	98	98	98	98	98	98

Design Day Demand(TJ/Day)

	2010	2011	2012	2013	2014	2015	2016	2017
TGVI	114.2	118.1	122.0	125.8	129.7	133.8	137.9	140.9

TGVI

TGVI Year end accounts by Rate Class

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
RGS	112,820	114,956	117,025	118,942	120,876	122,857	124,704	126,541
SCS1	6032	6112	6187	6255	6324	6397	6461	6526
SCS2	1458	1461	1463	1464	1465	1467	1468	1469
LCS1	1402	1405	1407	1408	1409	1411	1412	1413
LCS2	570	573	575	577	579	581	583	584
AGS	918	921	923	925	927	929	931	933
LCS3	148	150	152	153	154	156	157	158
HLF	6	6	6	6	6	6	6	6
ILF	8	8	8	8	8	8	8	8
Total	**123,362**	**125,592**	**127,746**	**129,738**	**131,748**	**133,812**	**135,730**	**137,638**

Percent change in Year end Accounts by Rate Class

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
RGS	1.97%	1.89%	1.80%	1.64%	1.63%	1.64%	1.50%	1.47%
SCS1	1.38%	1.33%	1.23%	1.10%	1.10%	1.15%	1.00%	1.01%
SCS2	0.21%	0.21%	0.14%	0.07%	0.07%	0.14%	0.07%	0.07%
LCS1	0.21%	0.21%	0.14%	0.07%	0.07%	0.14%	0.07%	0.07%
LCS2	0.53%	0.53%	0.35%	0.35%	0.35%	0.35%	0.34%	0.17%
AGS	0.33%	0.33%	0.22%	0.22%	0.22%	0.22%	0.22%	0.21%
LCS3	1.37%	1.35%	1.33%	0.66%	0.65%	1.30%	0.64%	0.64%
HLF	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ILF	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
RGS	43	42	42	42	41	41	40	40
SCS1	116	116	116	116	116	116	116	116
SCS2	325	325	325	325	325	325	325	325
LCS1	980	980	980	980	980	980	980	980
LCS2	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481
AGS	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259
LCS3	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911
HLF	19,585	19,585	19,585	19,585	19,585	19,585	19,585	19,585
ILF	12,197	12,197	12,197	12,197	12,197	12,197	12,197	12,197

Annual Demand by Rate Class(TJ)

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
RGS	4,821	4,866	4,907	4,940	4,972	5,004	5,030	5,053
SCS1	702	712	720	728	736	745	752	760
SCS2	474	475	475	476	476	477	477	477
LCS1	1,374	1,377	1,378	1,379	1,380	1,382	1,383	1,384
LCS2	1,414	1,422	1,427	1,432	1,437	1,442	1,447	1,449
AGS	1,156	1,160	1,162	1,165	1,167	1,170	1,172	1,175
LCS3	2,207	2,237	2,266	2,281	2,296	2,326	2,341	2,356
HLF	118	118	118	118	118	118	118	118
ILF	98	98	98	98	98	98	98	98

Design Day Demand(TJ/Day)

	2018	2019	2020	2021	2022	2023	2024	2025
TGVI	143.8	146.7	149.3	151.5	153.7	155.7	157.9	159.9

TGVI

TGVI Year end accounts by Rate Class

Rate Class	2026	2027	2028	2029	2030
RGS	128,370	130,174	131,982	133,824	135,689
SCS1	6591	6655	6719	6784	6849
SCS2	1470	1471	1472	1473	1474
LCS1	1414	1415	1416	1417	1418
LCS2	585	586	587	588	589
AGS	935	937	939	941	943
LCS3	159	160	161	162	163
HLF	6	6	6	6	6
ILF	8	8	8	8	8
Total	**139,538**	**141,412**	**143,290**	**145,203**	**147,139**

Percent change in Year end Accounts by Rate Class

Rate Class	2026	2027	2028	2029	2030
RGS	1.45%	1.41%	1.39%	1.40%	1.39%
SCS1	1.00%	0.97%	0.96%	0.97%	0.96%
SCS2	0.07%	0.07%	0.07%	0.07%	0.07%
LCS1	0.07%	0.07%	0.07%	0.07%	0.07%
LCS2	0.17%	0.17%	0.17%	0.17%	0.17%
AGS	0.21%	0.21%	0.21%	0.21%	0.21%
LCS3	0.63%	0.63%	0.63%	0.62%	0.62%
HLF	0.00%	0.00%	0.00%	0.00%	0.00%
ILF	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Rate Class	2026	2027	2028	2029	2030
RGS	40	39	39	38	38
SCS1	116	116	116	116	116
SCS2	325	325	325	325	325
LCS1	980	980	980	980	980
LCS2	2,481	2,481	2,481	2,481	2,481
AGS	1,259	1,259	1,259	1,259	1,259
LCS3	14,911	14,911	14,911	14,911	14,911
HLF	19,585	19,585	19,585	19,585	19,585
ILF	12,197	12,197	12,197	12,197	12,197

Annual Demand by Rate Class(TJ)

Rate Class	2026	2027	2028	2029	2030
RGS	5,075	5,094	5,112	5,130	5,147
SCS1	767	775	782	790	797
SCS2	478	478	478	479	479
LCS1	1,385	1,386	1,387	1,388	1,389
LCS2	1,452	1,454	1,457	1,459	1,461
AGS	1,177	1,180	1,182	1,185	1,187
LCS3	2,371	2,386	2,401	2,416	2,430
HLF	118	118	118	118	118
ILF	98	98	98	98	98

Design Day Demand(TJ/Day)

	2026	2027	2028	2029	2030
TGVI	161.9	163.8	165.7	167.6	169.6

TGW

TGW Year end accounts by Rate Class

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
SGS-1/2 RES	2,285	2,321	2,341	2,366	2,396	2,426	2,455	2,478
SGS-1/2 COM	173	175	178	181	184	187	190	192
LGS-1 COM	84	84	85	85	86	86	87	87
LGS-2 COM	51	52	52	53	53	53	53	54
LGS-3 COM	24	24	24	24	24	24	24	24

Percent change in Year end Accounts
By Rate Class

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
SGS-1/2 RES		1.6%	0.9%	1.1%	1.3%	1.3%	1.2%	0.9%
SGS-1/2 COM		1.2%	1.7%	1.7%	1.7%	1.6%	1.6%	1.1%
LGS-1 COM		0.0%	1.2%	0.0%	1.2%	0.0%	1.2%	0.0%
LGS-2 COM		2.0%	0.0%	1.9%	0.0%	0.0%	0.0%	1.9%
LGS-3 COM		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer
by Rate Class(GJ)

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
SGS-1/2 RES	82	82	82	82	82	82	82	82
SGS-1/2 COM	251	251	251	251	251	251	251	251
LGS-1 COM	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185
LGS-2 COM	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447
LGS-3 COM	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150

Annual Demand by Rate Class(TJ)

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
SGS-1/2 RES	188	191	193	195	197	200	202	204
SGS-1/2 COM	43	44	45	45	46	47	48	48
LGS-1 COM	100	100	101	101	102	102	103	103
LGS-2 COM	125	127	127	130	130	130	130	132
LGS-3 COM	220	220	220	220	220	220	220	220

Design Day Demand(TJ/Day)

	2010	2011	2012	2013	2014	2015	2016	2017
TGW	7.1	7.2	7.2	7.3	7.3	7.4	7.4	7.5

TGW

TGW Year end accounts by Rate Class

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
SGS-1/2 RES	2,498	2,520	2,538	2,555	2,572	2,586	2,599	2,612
SGS-1/2 COM	194	196	198	200	202	203	204	205
LGS-1 COM	88	88	89	89	90	90	91	91
LGS-2 COM	54	54	54	55	55	55	55	56
LGS-3 COM	24	24	24	24	24	24	24	24

Percent change in Year end Accounts By Rate Class

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
SGS-1/2 RES	0.8%	0.9%	0.7%	0.7%	0.7%	0.5%	0.5%	0.5%
SGS-1/2 COM	1.0%	1.0%	1.0%	1.0%	1.0%	0.5%	0.5%	0.5%
LGS-1 COM	1.1%	0.0%	1.1%	0.0%	1.1%	0.0%	1.1%	0.0%
LGS-2 COM	0.0%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	1.8%
LGS-3 COM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer by Rate Class(GJ)

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
SGS-1/2 RES	82	82	82	82	82	82	82	82
SGS-1/2 COM	251	251	251	251	251	251	251	251
LGS-1 COM	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185
LGS-2 COM	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447
LGS-3 COM	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150

Annual Demand by Rate Class(TJ)

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
SGS-1/2 RES	205	207	209	210	211	213	214	215
SGS-1/2 COM	49	49	50	50	51	51	51	51
LGS-1 COM	104	104	105	105	107	107	108	108
LGS-2 COM	132	132	132	135	135	135	135	137
LGS-3 COM	220	220	220	220	220	220	220	220

Design Day Demand(TJ/Day)

	2018	2019	2020	2021	2022	2023	2024	2025
TGW	7.5	7.6	7.6	7.6	7.7	7.7	7.7	7.8

TGW

TGW Year end accounts by Rate Class

Rate Class	2026	2027	2028	2029	2030
SGS-1/2 RES	2,624	2,638	2,650	2,662	2,673
SGS-1/2 COM	206	207	208	209	210
LGS-1 COM	92	92	93	93	94
LGS-2 COM	56	56	56	57	57
LGS-3 COM	24	24	24	24	24

Percent change in Year end Accounts By Rate Class

Rate Class	2026	2027	2028	2029	2030
SGS-1/2 RES	0.5%	0.5%	0.5%	0.5%	0.4%
SGS-1/2 COM	0.5%	0.5%	0.5%	0.5%	0.5%
LGS-1 COM	1.1%	0.0%	1.1%	0.0%	1.1%
LGS-2 COM	0.0%	0.0%	0.0%	1.8%	0.0%
LGS-3 COM	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer by Rate Class(GJ)

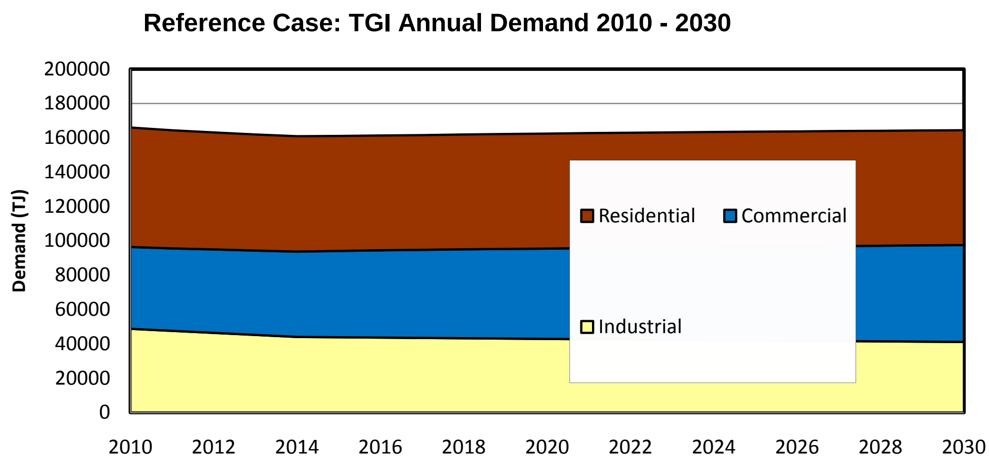
Rate Class	2026	2027	2028	2029	2030
SGS-1/2 RES	82	82	82	82	82
SGS-1/2 COM	251	251	251	251	251
LGS-1 COM	1,185	1,185	1,185	1,185	1,185
LGS-2 COM	2,447	2,447	2,447	2,447	2,447
LGS-3 COM	9,150	9,150	9,150	9,150	9,150

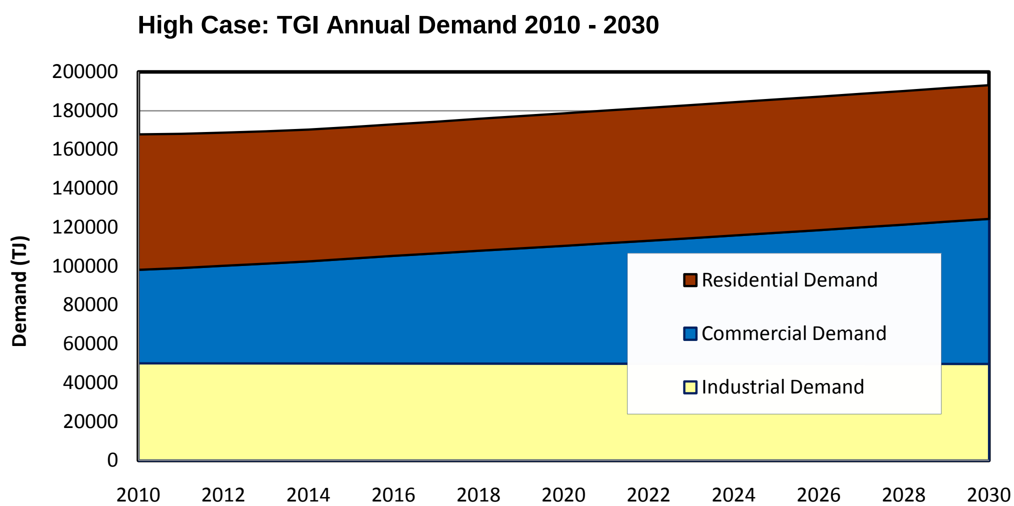
Annual Demand by Rate Class(TJ)

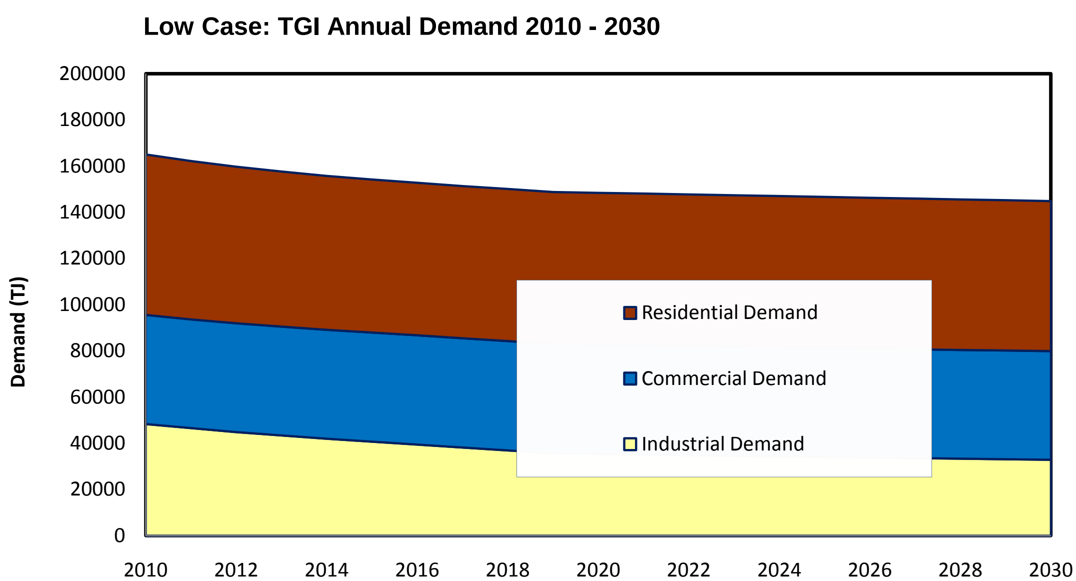
Rate Class	2026	2027	2028	2029	2030
SGS-1/2 RES	216	217	218	219	220
SGS-1/2 COM	52	52	52	52	53
LGS-1 COM	109	109	110	110	111
LGS-2 COM	137	137	137	139	139
LGS-3 COM	220	220	220	220	220

Design Day Demand(TJ/Day)

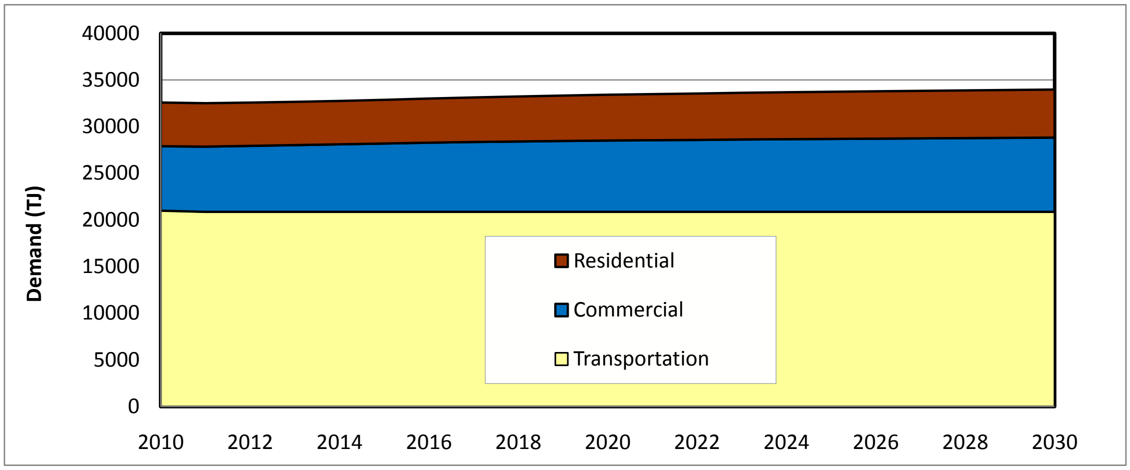
	2026	2027	2028	2029	2030
TGW	7.8	7.8	7.8	7.9	7.9


Reference Case: TGI Annual Demand 2010 - 2030
Demand (TJ)
200000
180000
160000
140000
120000
100000
80000
60000
40000
20000
0
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Residential
Commercial
Industrial

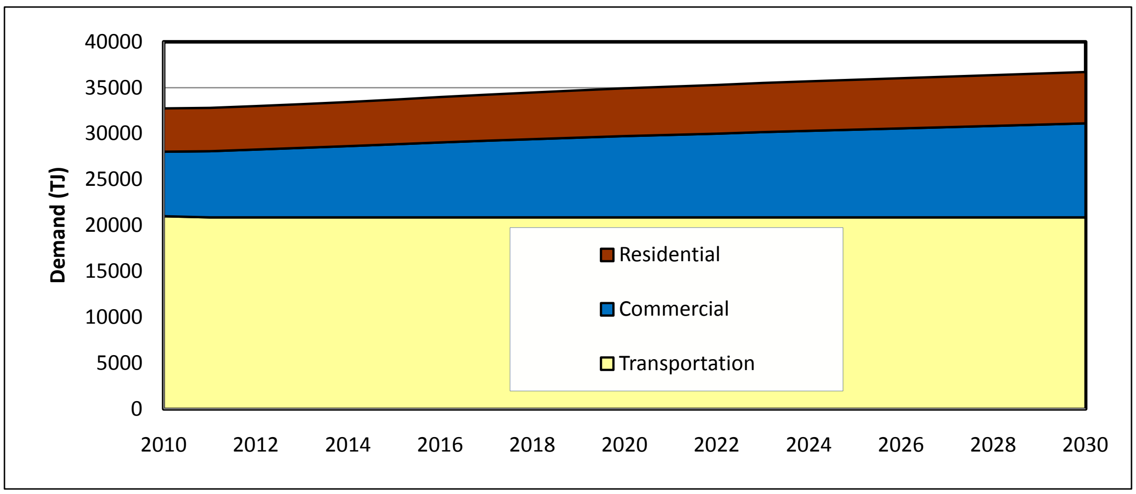

High Case: TGI Annual Demand 2010 - 2030
Demand (TJ)
200000
180000
160000
140000
120000
100000
80000
60000
40000
20000
0
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Residential Demand
Commercial Demand
Industrial Demand


Low Case: TGI Annual Demand 2010 - 2030
Demand (TJ)
200000
180000
160000
140000
120000
100000
80000
60000
40000
20000
0
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Residential Demand
Commercial Demand
Industrial Demand

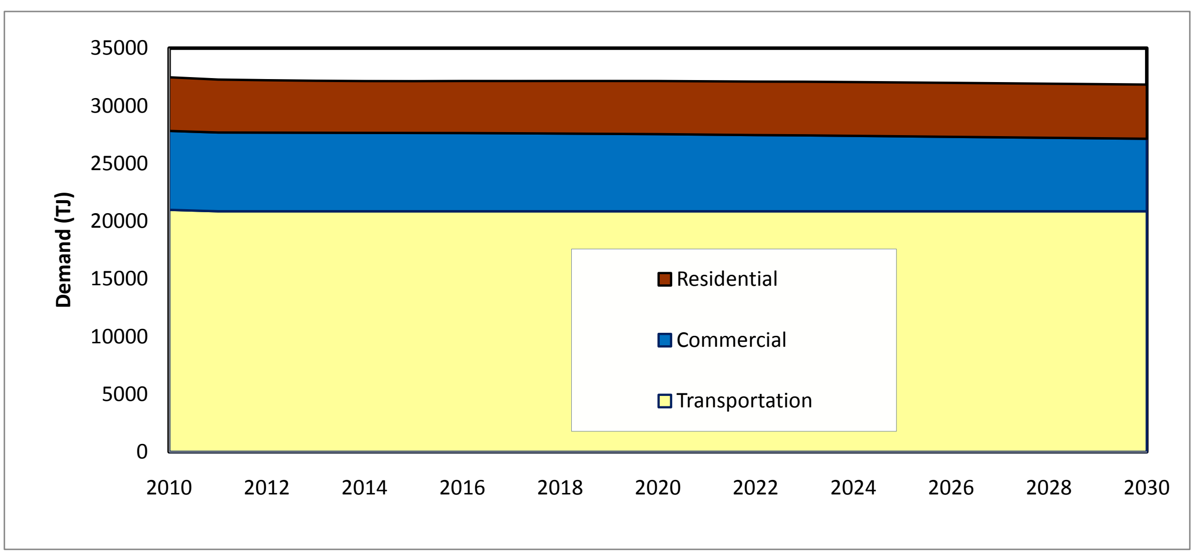
Reference Case: TGVI Annual Demand 2010 - 2030



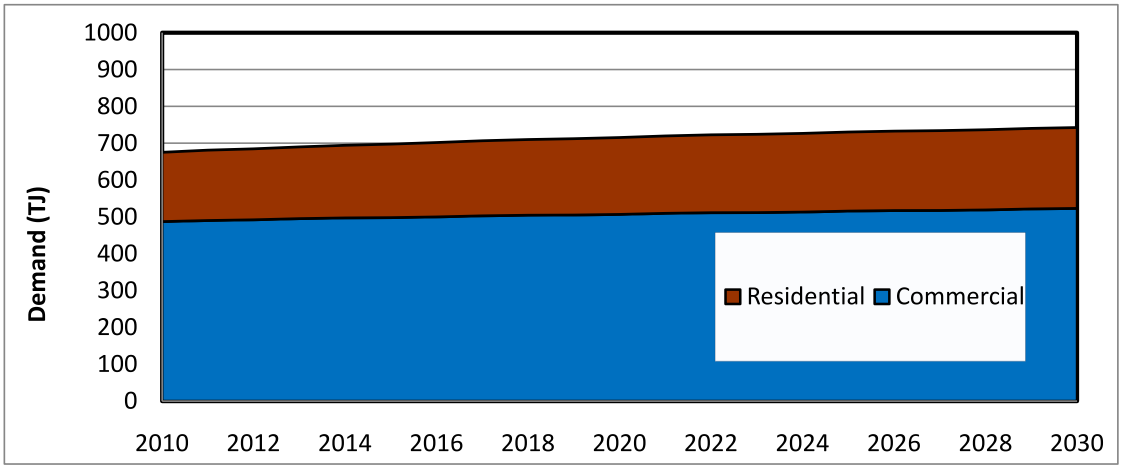
High Case: TGVI Total Annual Demand 2010 - 2030



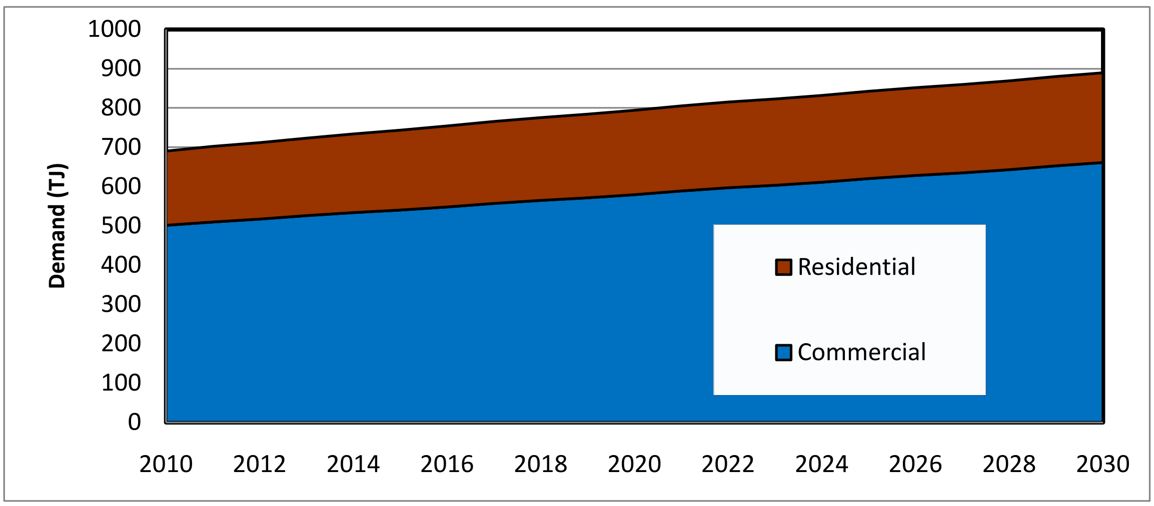
Low case: TGVI Total Annual Demand 2010 - 2030



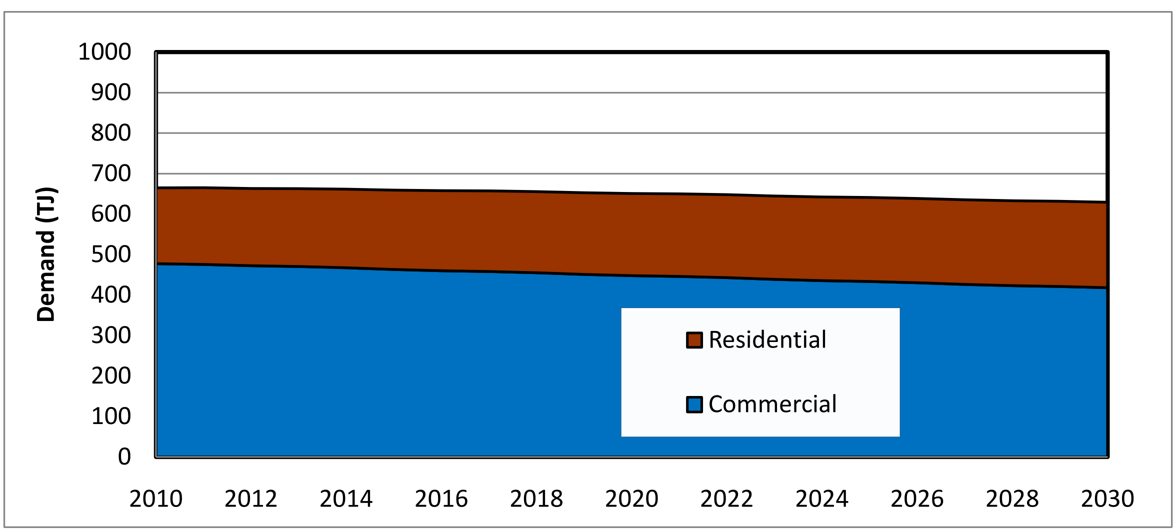
Reference Case: TGW Annual Demand 2010 - 2030



High Case: TGW Total Annual Demand 2010 - 2030



Low Case: TGW Total Annual Demand 2010 - 2030



DESIGN DAY DEMAND FORECAST METHODOLOGY

1. Introduction

Design day demand (also called Peak Day Demand) is the maximum consumption during the coldest weather day expected to occur over a 20 year period. Through first analyzing weather to determine appropriate design (unusually cold weather) day weather conditions, and then by identifying the relationship between weather and natural gas consumption, the forecast of design day demand is developed. The forecast of design day demand is a crucial input into the Terasen Utilities' key activities of securing an adequate supply of natural gas, and also ensuring that the infrastructure is capable of delivering that natural gas where and when needed. Terasen applies a consistent methodology to determine design day demand for each of its companies, Terasen Gas Inc., Terasen Gas (Vancouver Island) inc., and Terasen Gas (Whistler) Inc., with minor differences resulting from variations in the way data is collected and how customer classes are structured.

Stakeholder feedback during review of the 2008 Terasen Gas Resource Plan suggested that the Terasen Utilities review the current methodology for estimating peak use per customer due to the issue of multi-colinearity in the factors (HDD[1] 13 and HDD18) used to model the design day temperature. For this Long Term Resource Plan, a number of models were investigated to determine their impact on natural gas consumption. A spline model[2] was identified as providing an excellent fit to the historical data, while also avoiding the potential issues associated with multi-colinearity. The results of both the spline model and HDD13 / HDD18 model were compared and found to be very similar. The results of the spline model analysis is presented in this Appendix; however, the Utilities intend to continue reviewing both the current HDD13 / HDD18 model and the spline model, and potentially other models as they forecast design day demand, and continuously seek to improve forecasting processes.

2. Design Day Weather

Design day weather conditions are estimated using a methodology consistent with what has been used in the past, an Extreme Value Analysis (using Dr. Gumbel's extreme distribution). Extreme Value Analysis is a statistical technique used to model observed data extremes in order to allow for generalizations about the likely recurrences of those events. This type of analysis is the accepted standard in Canada, and is approved by the Atmospheric Environment Service of Environment Canada.

[1] HDD = Heating Degree Day. In the current analysis a regression is run on historic weather and demand data using HDD 13 and HDD 18 to identify the expected demand on a design day.
[2] A regression model that analyses the relationship between variables that has been found appropriate for other weather related modelling exercises.

At Terasen, the data extremes are very cold temperatures (the coldest temperature experienced in each year), and the objective is to identify the coldest temperature that would be expected to reoccur once every twenty years.

Table 1: Design Day Weather by Region

Service Area	Temperature(Degrees Celsius)
Lower Mainland	-12.8
Inland	-26.1
Columbia	-31.4
Fort Nelson	-43.1
TGVI	-10.7
TGW	-23.3

The design day temperatures, illustrated above in Table 1, are a result of analyzing historical weather data (the coldest day in each year) in each of Terasen's sales regions using Dr. Gumbel's extreme distribution, a non-linear regression model.

3. Modeling Design Day Demand

Heating degree days based on different reference points (ie. HDD13, HDD14,…, HDD18) were investigated, as were a number of other factors impacting natural gas consumption such as wind speed, hours of sunlight, rainfall, and day of week. These variables were tested through the use of several different statistical models, identified through attending conferences, seminars, and also through informal discussions with other utilities. Those models included simple linear regression, multiple linear regression, piecewise linear regression and also spline regressions, and they incorporated both the individual factors and combinations of multiple factors that impact natural gas consumption. The results of Terasen's analysis indicate temperature is the only variable that consistently shows a high degree of significance across all regions, and further indicates the spline regression approach is most appropriate for estimating design day demand.

The Spline model was selected as the best model as it not only provides an excellent fit to the historical data, but also avoids the potential issues associated with multi-colinearity (an issue raised during the 2008 Resource Planning process). The Spline model incorporates two temperature reference points (13 and 18 degrees Celsius), and essentially provides three estimates of consumption:

1) It estimates the base load consumption, when temperature is above the higher temperature reference point (18 degrees Celsius);

2) It estimates the temperature sensitive consumption while the temperature is between the two temperature reference points (13 and 18 degrees Celsius); and,

3) It estimates the temperature sensitive consumption when the temperature drops below the lower temperature reference point (13 degrees Celsius).

The functional form of the Spline model is:

$\text{Consumption}_i = \beta0 + \beta1\text{Spline1}_i + \beta2\text{Spline2}_i + \beta3\text{Spline3}_i$

Where:

$\text{Spline } 1_i = \text{Max}(0, T_i - \text{Tref1})$

$\text{Spline } 2_i = \text{Max}((\text{Tref1} - T_i, 0),\text{Tref1} - \text{Tref2})$

$\text{Spline } 3_i = \text{Max}(0,\text{Tref2} - T_i)$

And T_i is the average temperature for day I, Tref1 is the higher temperature reference point (18 degrees Celsius), and Tref2 is the lower temperature reference point (13 degrees Celsius).

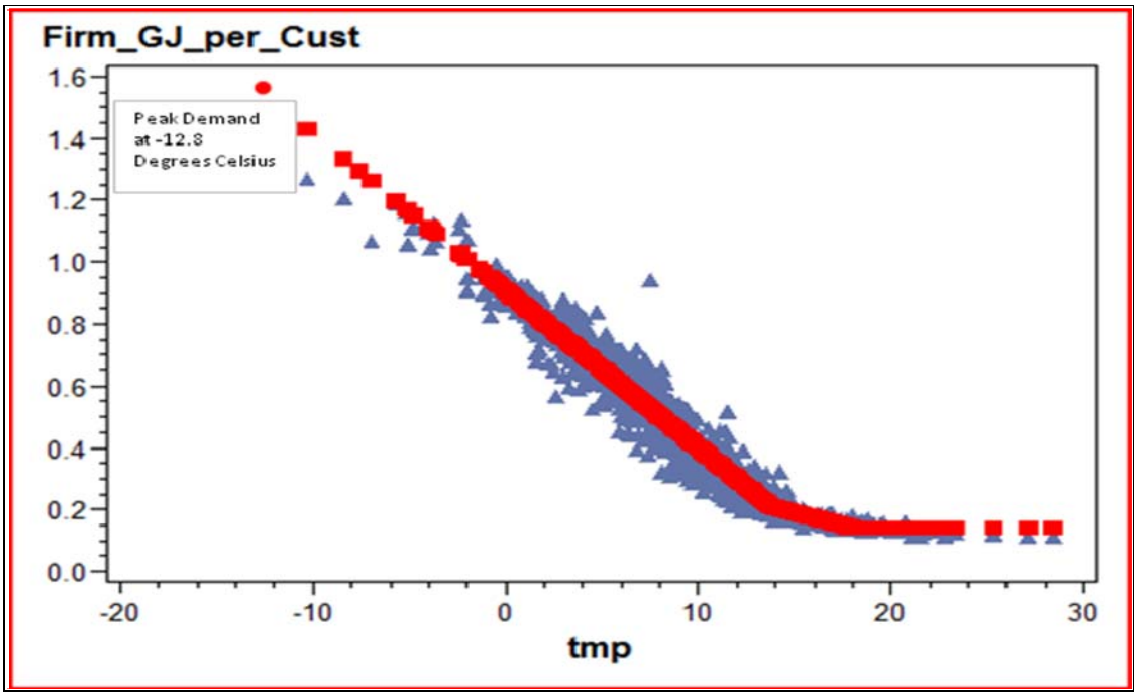
By applying the above model to the historical consumption and temperature data for each of Terasen's sales territories, the parameter estimates were derived. The following table illustrates the goodness of fit tests that were analyzed to determine the reasonableness of the model.

As can be seen from Table 2, each of the variables in the model shows a high degree of significance, and the R-square statistic indicates and excellent fit for the model as a whole. The following, Figure 1, plots the daily core sendout over the 2006, 2007, and 2008 contract years together with the daily temperatures, and also illustrates the predicted values based upon the spline modeling that was performed for the Lower Mainland sales territory.

Table 2: Regression results by Region

Region	GasYear	P values for Regression Parameters: Intercept	spline1	spline2	spline3	R-Square Value	Peak UPC
COL	2006	<.0001	0.593	0.000	<.0001	97%	1.3178
COL	2007	<.0001	0.608	<.0001	<.0001	96%	1.2545
COL	2008	<.0001	0.474	0.000	<.0001	96%	1.2227
FTN	2006	<.0001	0.765	0.011	<.0001	99%	2.3638
FTN	2007	<.0001	0.419	0.001	<.0001	99%	2.3186
FTN	2008	<.0001	0.377	0.004	<.0001	98%	2.2721
INL	2006	<.0001	0.045	0.022	<.0001	98%	1.3402
INL	2007	<.0001	0.039	0.265	<.0001	98%	1.2794
INL	2008	<.0001	0.035	0.079	<.0001	98%	1.2501
LML	2006	<.0001	0.708	<.0001	<.0001	96%	1.6221
LML	2007	<.0001	0.757	<.0001	<.0001	96%	1.5910
LML	2008	<.0001	0.440	<.0001	<.0001	95%	1.5189
TGVI	2006	<.0001	0.843	<.0001	<.0001	95%	1.1903
TGVI	2007	<.0001	0.898	<.0001	<.0001	94%	1.1159
TGVI	2008	<.0001	0.814	<.0001	<.0001	95%	1.0791

Figure 1: Firm demand per customer for LML

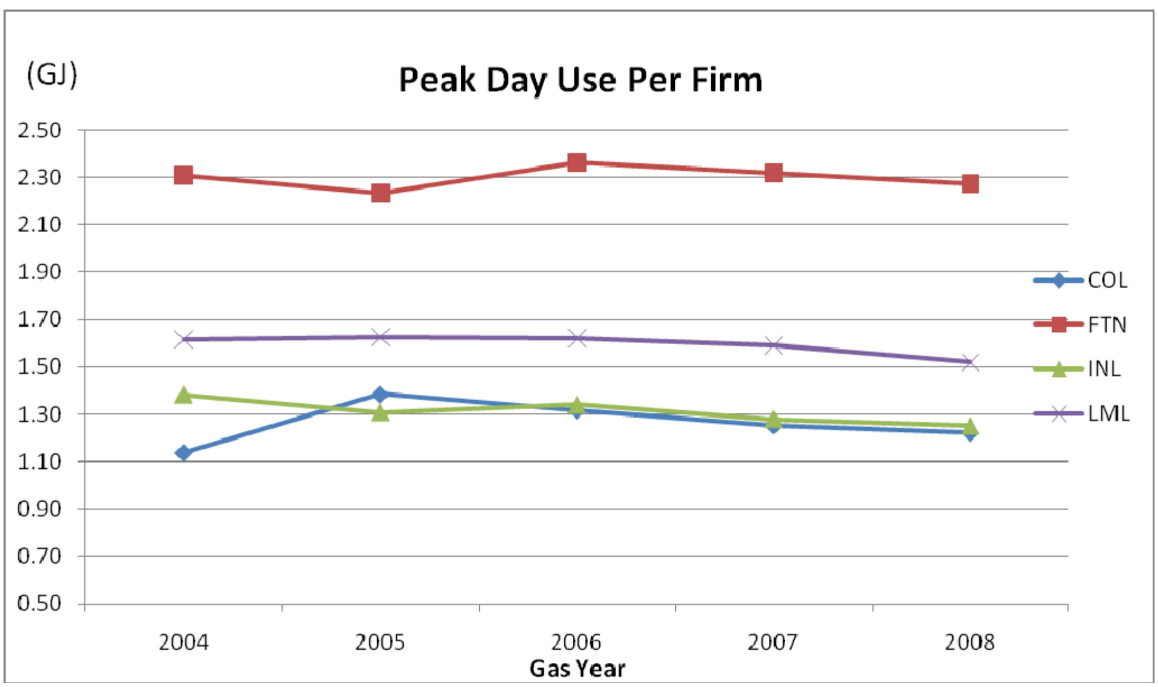


Based on the results of the goodness of fit tests and also the supporting chart in Figure 3 above, the spline model is considered to be a good predictor of design day demand for Terasen Utilities and is the proposed approach as it is developed to date. Although Utilities are in early stages of refining their peak day demand methodology as described above, going forward we will continue to explore other methods and take the necessary steps (if needed) to ensure the design day demand methodology remains both reasonable and appropriate for use in both resource planning and revenue requirement activities.

4. Historic Design Day Demand

Although Terasen considers the most recent three-year period to be most relevant when estimating future design day demand, historic design day demand per customer has been tracked for a longer period. Figure 2, illustrates the historic design day demand per customer over the 2003 through 2008 contract years, for each of TGI's sales territories.

Figure 2: Design Day Use Per Firm Account



As illustrated above in Figure 2, design day demand per account has fluctuated over the years, with both increases and declines being experienced. During this same period, Terasen Utilities has experienced consistent declines in residential average use per customer.

Due to the relative stability in design day use per customer and also considering the fact that Terasen is the provider of last resort, design day use per customer is assumed to remain constant over the forecast period.

5. Forecast Design Day Demand

Through applying the methodology described above, Terasen has developed a forecast of design day demand for each of its company's and sales territories. Having conducted a thorough analysis of various methods, the forecasting methodology used to develop design day demand for the Terasen Utilities is both reasonable and appropriate for use in the long term resource planning process. The following, Table 3, illustrates the design day demand over the period 2009 through 2014.

Table 3: Design Day Demand

Contract Year	09/10	10/11	11/12	12/13	13/14	14/15
Columbia	28	29	29	30	30	30
Coastal	918	926	933	940	948	955
Ft. Nelson	5	6	6	6	6	6
Inland	297	301	305	309	313	317
TGVI	110	114	118	122	126	130
TGW	7	7	7	7	7	7

Discussion of Proposed Changes to the Terasen Utilities' Natural Gas Annual Demand Forecast Methodology for Residential Customers

1. Background

To continue meeting the changing needs of its customers, the Terasen Utilities must be able to offer complete, integrated energy solutions that include new energy efficiency and conservation ("EEC") programs and alternative, low carbon and renewable energy solutions. The development of renewable thermal energy solutions, increased energy efficiency programs and low carbon transportation fuel alternatives is not expected to have a material impact on demand over the next few years. However, as demand for these services grows and evolves over time, so too does the Utilities' need to forecast demand for these products and services, assess the impact on conventional natural gas demand and also measure the impacts of these services on GHG emission reductions, system efficiencies and delivery rates.

The Utilities expect that the energy use patterns of new residential customers will evolve to be quite different than those of the existing customer base today. The growing pace of change in energy policy, technology options, efficiency advancements, housing mix, customer behavior, attitudes and other factors need to be addressed for each of these customer groups as part of forecasting demand for both natural gas and alternative energy solutions. For these reasons, the Utilities are adopting an end-use natural gas demand forecasting methodology that complements and may in the future replace its current natural gas demand forecasting approach. Where the Terasen Utilities' current forecasting methodology examines use rates within the residential customer service classes and applies future assumptions about these use rates to existing and new customers alike, our new approach will allow better consideration of differences in behaviors and future energy decisions between new and existing customers.

Given that the existing customer base is so large, they will continue to have the most significant impact on residential energy demand. However, as new customers have a much broader range of energy type and technology choices to choose from, they will have a growing and changing impact on future natural gas demand.

The type of energy technology solutions chosen and over all energy consumption is also expected to reflect differences in housing type. While the Utilities are not shifting the methodology by which we forecast total natural gas customer additions, the proposed methodology does include a break-out of existing customers and new customer additions by housing type within the analysis of future demand. At this time, this breakout is limited to single family dwellings ("SFD") and townhouse type multi-family dwellings ("MFD")[1].

The Utilities are in the early stages of refining their forecasting methodologies. This appendix presents our approach as it is developed to date. More research and analysis is required to more fully understand customers' changing behaviors, needs and energy decision making considerations, in order to more fully employ our end use approach to demand forecasting across all service territories. The Utilities will continue to refine this approach as more information about customer decisions and behaviors, as well as the performance of new technologies and EEC programs becomes available. For planning purposes, the Terasen Utilities will also continue to prepare a residential customer additions and natural gas demand forecast using its current methodology.

2. Proposed Methodology

The Terasen Utilities' proposed new approach incorporates customer end use data such as the type of appliance broken out by end uses (space heating, water heating etc), housing type and region separated by existing and new customers. For the new residential customers, customer additions is further broken out by housing types and end use and the use per customer is based on assumptions from the most recent building codes and standards that are in affect for new home construction in BC. This revised approach will allow for greater flexibility to determine possible outcome because inputs that are derived from studies and research can be modified and changed as customer energy solutions and behaviors evolve overtime.

For example, all new residential natural gas customers today must install a high efficiency furnace for space heating to remain in compliance with building codes and standards. These new customers will therefore all join the Utilities' customer base at a substantially different rate of use than that of the existing customer base. The existing customer base will shift use rates much more slowly as the existing stock of lower efficiency furnaces is switched out for high efficiency models over time, as existing furnaces reach the end of their service life. Forecasting these two groups separately will allow better consideration of the impact of new customer additions on over all annual

[1] The majority of high density residential customers (apartment buildings) have historically been on a common service and are therefore part of the Utilities' commercial service class customers and are not included at this time in the example forecast analysis.

and design day demand, and will allow the Utilities to better examine the impact of EEC programs that could speed the pace of furnace replacements among existing customers.

Energy policy as well as the cost and technical ability to implement alternative, renewable thermal energy solutions are further conditions that will impact new customers differently than they will the Utilities' existing customer base. The current practice of multiplying average use rates by total customers within customer service classes will not permit the necessary analysis to fully examine the impacts of these conditions. An end-use approach with better consideration of new versus existing customers is needed.

The following discussion presents the proposed methodology as applied first to the existing customer base, and then to the new customer additions. The addition of these two demand forecasts then provides the total demand forecast results. Finally, the underlying assumptions for the forecasting of demand within each of the customer groups are then presented.

2.1 Existing Customer Demand

The end use forecast is based on the following model.

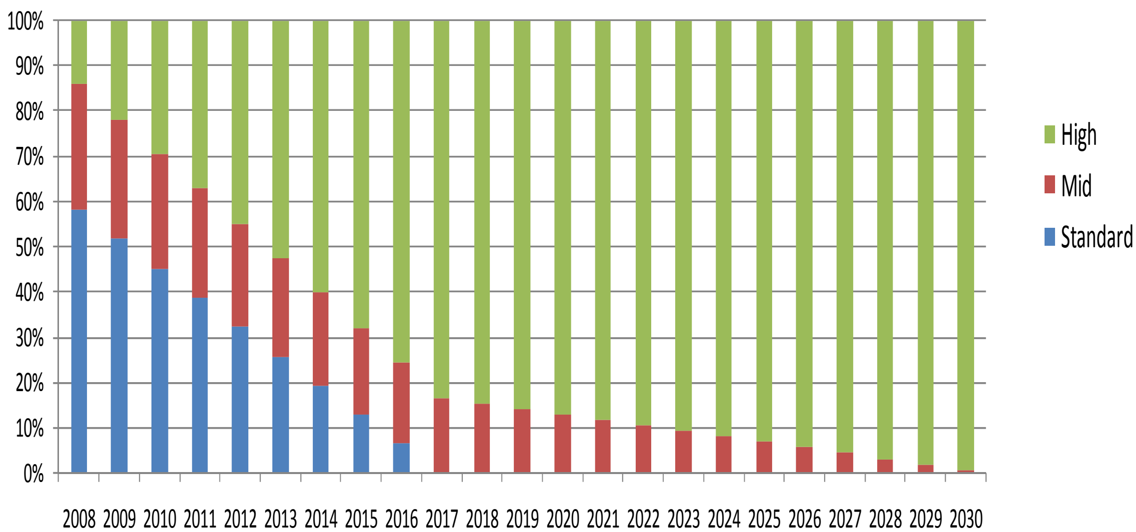
$RES_X = \sum_R \sum_E \sum_H C_{(REH)} * UPC_{E(R,\ E,\ H)}$, where:

- RES_X represents the annual residential consumption for existing customers and is an estimate based on the input assumptions.
- R indexes a specific Region (LML & INT)
- E indexes a specific end use by appliance (space heating, water heating, fireplace, range, BBQ, dryer, pool, hot tub)
- H indexes a specific housing types (Single family dwelling, multifamily dwelling, Apartments)
- C represents an estimate of the number of existing residential customers for that end use and by housing type
- UPC (Use Per Customer) represents the average residential use per customer by housing type, end use and region for existing customers.

No new customer additions are included in this calculation. For the 2010 Resource Plan, the year 2009 is considered the base year for the existing customers and then a forecast is developed on the proportion of existing customers upgrading to efficient appliances each year based on certain set of assumptions broken out changes by housing type and end use over the planning period. In essence, the total number of customers remain the same[2] each year and what changes is the appliance mix over a period of time based on data from 2008 REUS and historical trends. The appliance mix by housing type derived from the 2008 REUS was applied to the 2009 year end customer count, which resulted in an estimated "base year" for this example. By developing a set of assumptions[3] around appliance retrofit activity, shifts in housing type, and future appliance penetration rates, the existing demand forecast was created.

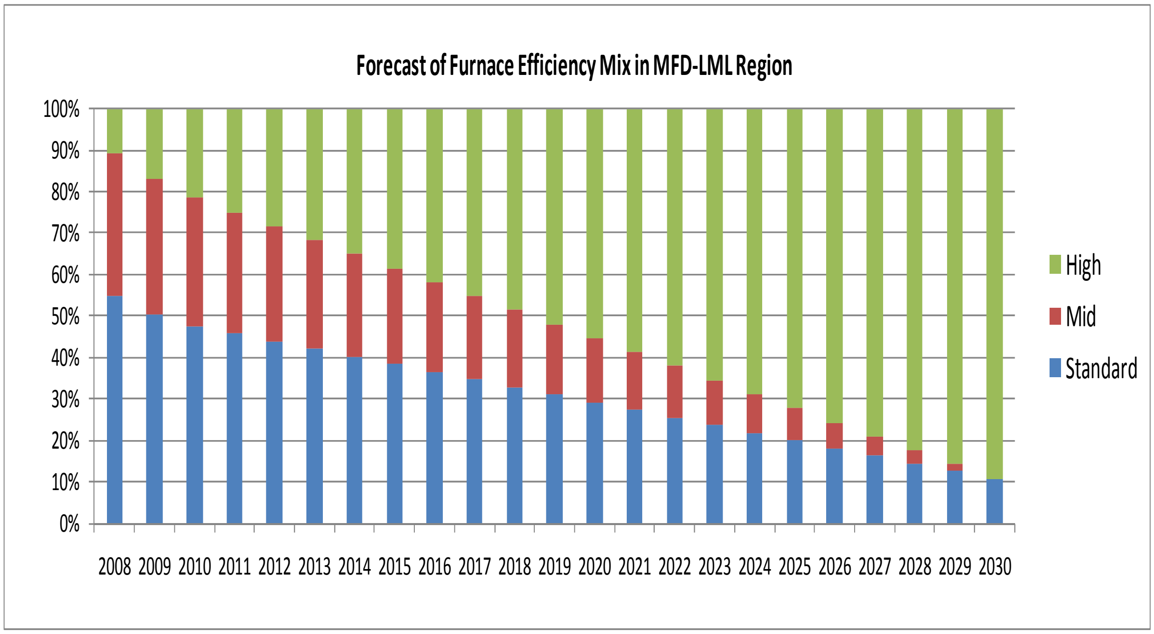
Figures 1 and 2 illustrate the forecasted shift in space heating appliances by end use and housing type for the Lower Mainland region. This data, combined with consumption levels based on the equipment efficiencies, become inputs into the existing customer demand.

Figure 1: Forecast of Furnace Efficiency Mix - SFD, Lower Mainland



[2] Existing customer turnover is captured in net additions forecast.
[3] These assumptions will be tested and refined as the proposed new demand forecast methodology is more fully developed.

Figure 2: Forecast of Furnace Efficiency Mix - MFD, Lower Mainland



2.2 New Customer Demand

For the new residential customers the model is identical as illustrated above except that the customer additions is broken out by housing types and end use and the use per customer is based on assumptions from the most recent building codes and standards that are in affect for new home construction in BC.

$$RES_N = \sum_R \sum_E \sum_H C_{(REH)} * UPC_{N(R,\ E,\ H)}$$

- RES_N is the residential consumption for new customers
- R indexes a specific Region (LML & INT)
- E indexes a specific end use (space heating, water heating, fireplace, range, BBQ, dryer, pool, hot tub)
- H indexes a specific housing types (single family dwelling, multifamily dwelling, Apartments
- C represents the number of new residential customers for that end use and by housing type
- UPC (Use per customer) represents the average residential use per customer by housing type, end use and region for new customers

For new customer demand, the total number of customer additions is identical to that of the traditional demand forecast but is further segmented by housing type and end use, based on appliance penetration rates and historical capture rates. The new customer demand is estimated by end use, housing type, and Region by multiplying the customer additions and use per customer after analyzing estimated efficiency levels and building codes and standards.

2.3 Total Demand

$$Res_T = \sum RES_E + \sum RES_N$$

Where

- Res_T is the total demand forecast
- RES_E is the existing stock demand forecast
- RES_N is the new stock demand forecast

The total residential demand forecast is made up of two components: the forecast of existing customer demand and the forecast of new customer demand. The total residential forecast demand can be further segmented by housing type, end use and region. The details of the underlying assumptions are described in more detail below.

As an example, Figure 5 illustrates the existing and new residential customer space heating demand for all housing types for the LML region. The overall existing space heating demand (Figure 3) declines gradually as customers shift to high efficiency appliances while the new customer space heating demand (Figure 4) trends upward from increased customer additions and a more stable use per customer.

Figure 3: Existing Customer Space Heating Demand-LML

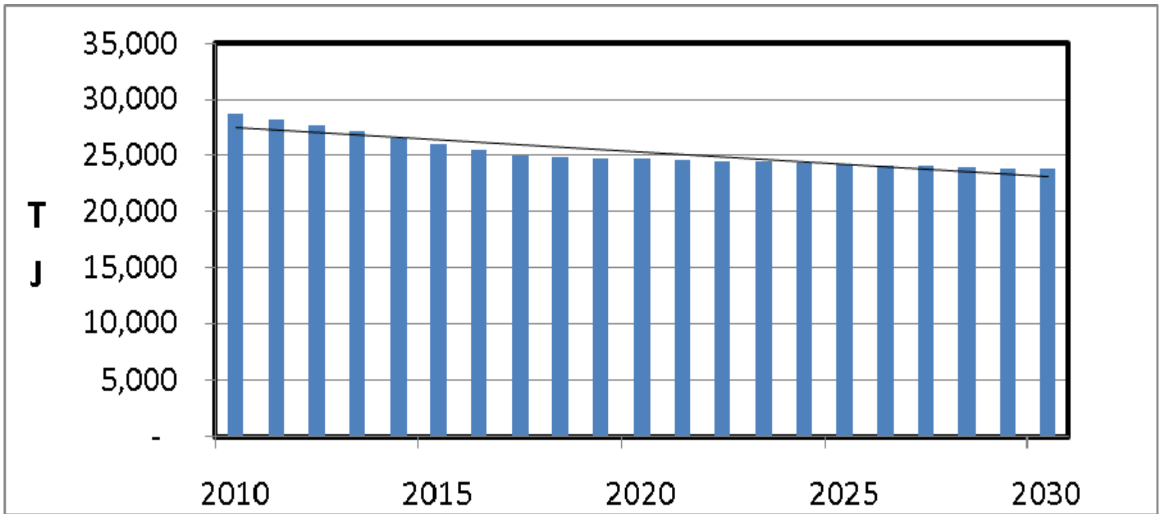
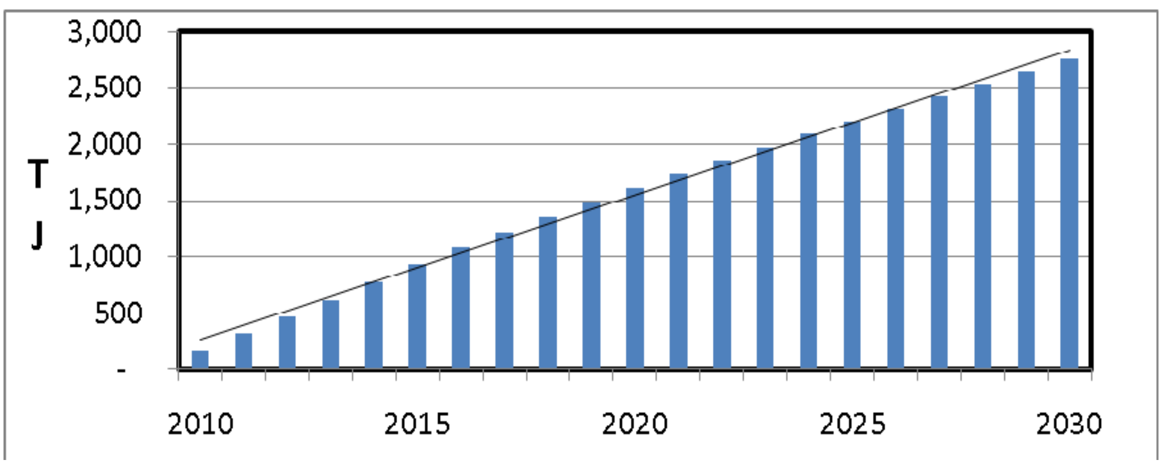
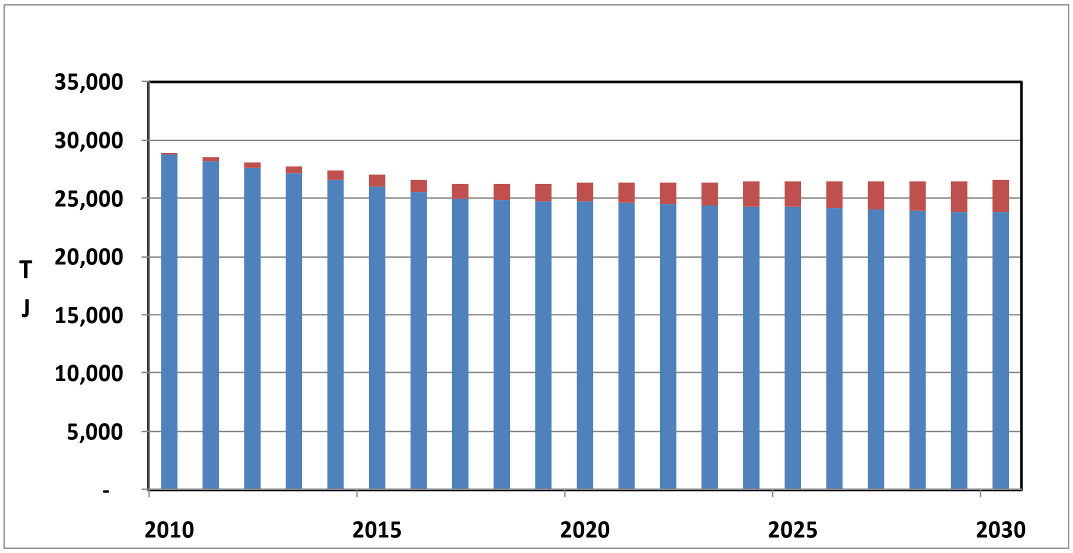


Figure 4: New Customer Space heating Demand -LML



The total space heating demand is illustrated in the Figure 5 below which combines the existing customer and new customer heating demand.

Figure 5: Total space heating demand -LML Region



3. Underlying Assumptions and Analyses

The assumptions and analyses described below refer specifically to this proposed methodology. These assumptions are based on the data available from the recently completed residential end use study (REUS 2008) and expected trends from the existing EEC programs and other external factors like building codes and standards and housing starts. The Utilities will monitor the application of these assumptions and conduct additional research to further address the data gaps and update the inputs when additional data becomes available. An overview of the key inputs and assumptions are described below

3.1 Use per customer

Individual use per customer is developed by housing type, end use and region for the residential customer service class. For existing customers, the use rate forecast by end use and housing type is estimated from the recently completed 2008 REUS. The end use is split by space heating, water heating and all the other end uses are grouped into an “others” category. The “others” category includes secondary space heating, decorative fireplace, heater fireplace, range, BBQ, Dryer, Pool & hot tub.

A Conditional Demand Analysis ('CDA') was conducted as part of the 2008 REUS to estimate consumption for a variety of gas end uses. The results of the CDA provide a key input into the end use demand model. CDA is a statistical approach that disaggregates total household consumption into Unit energy consumption (UEC) for several residential end uses. CDA is based on the notion that total household consumption is directly related to the stock of end use appliances present in the dwelling and the energy consumption levels associated with those end uses (UECs). The basic conditional demand model can be represented as:

$$HEC_{ht} = \sum UEC_{aht} S_{ah}$$

Where:

- HEC_{ht} represents the total energy consumption by household *h* in month t,
- UEC_{aht} represents the energy consumption through end use *a* by household h in month t,
- S_{ah} represents the presence or absence of end use *a* in household *h.*

The UECs for these end uses are modeled as functions of appropriate variables such as end use features, dwelling characteristics and household utilization patterns. The 2008 REUS discusses the CDA methodology, model and the assumptions in greater detail.

The results of the conditional demand analysis are expressed by end use, housing type and region. For instance the primary space heating unit energy consumption by dwelling type is shown in Table 1.

Table 1: Primary Gas Space Heating UEC by Dwelling Type

Dwelling Type	LM	INT	TGVI	TGW	FN	2008 TG Average
SFD	64.6	52.3	43.9	77.7	113.4	59.5
VSD	5.7	13.9	**	-	-	7.1
MFD	34.4	33.0	21.0	33.4*	-	33.5
Average	**62.0**	**51.6**	**43.0**	**66.9**	**113.4**	**57.8**

* Small sample size (less than 30 households with end use present).
** Insufficient sample size (less than 5 households with end use present).

Source: 2008 *Residential End Use Study.*

The Utilities incorporated the results of the CDA to further estimate the consumption by region, end use and appliance. For instance the primary space heating was further segmented by standard, mid and high efficiency furnaces, and by housing type and region. This level of detail is needed to build the end use model and assess the impact on demand and perform sensitivities as the existing customers shift annually to higher efficient appliances by end use and housing type. The impact of this shift on space heating is illustrated in Figure 3 above.

2008 REUS survey data provides estimates of appliance penetration rates and end use consumption by appliance and housing types for LML and INT regions. The same set of assumptions was then extrapolated for 2009 actual customers in each of the LML and INT regions. The sample demand forecast was then developed by making assumptions about the percentage shift in the proportion of customers upgrading to high efficient appliances annually by dwelling type and by end use and multiplying that by respective appliance unit energy consumption[4]. The penetration rates and the housing mix are held constant throughout the forecast period in absence of any other information.

For new customers the assumptions made under the reference case are that a high efficiency furnace would be used for space heating and minimum 0.62 efficient hot water tanks for domestic hot water heating for the planning period based on the current building codes and standards in place. In the "others" category, all the UEC's are held constant for the planning period based on the 2008 REUS. Though the Utilities understand that there are opportunities for efficiency improvements in certain end uses such as fireplaces, in the absence of any formal codes or standards in place at this point in time, we have kept the usage constant in this example.

3.2 Customer additions

For the existing customer base, the total number of customers at year-end 2009 is assumed to remain constant over the entire 20 year planning period and is also split by housing type, end use and region based on inputs from the 2008 REUS. As previously stated, what is assumed to change each year is the proportion of existing customers upgrading to high efficient appliances by end use and housing type based on inputs from the 2008 REUS.

For new customers, the total number of customer additions[5] is drawn from the current customer forecast. The forecast of customer additions is based on latest economic

[4] Based on internal analysis using CDA estimates as inputs
[5] Existing customer turnover is captured in customer additions.

analysis from the BC government, major banks, CMHC and is also reviewed for consistency with the trends in household formations. Under the current methodology a forecast is developed for the entire customer class, but under the proposed methodology the total is segmented by housing type and end use based on historical capture rates and penetration rates identified in the 2008 REUS. The forecast of customer additions across different end uses and by appliance type allows Terasen Gas to vary the input assumptions and assess impact on demand and GHG emissions from different scenarios.

4. Information Gaps and Recommended Actions

The end use methodology proposed by Terasen is in the initial stages but plans to refine it as more REUS studies are completed and actual results become available over time. At this time, insufficient end use data is available for commercial customer classes in general and also for residential customer classes in some of the smaller service areas to apply this methodology to all customer classes and service regions. Additionally, the survey data from the 2008 REUS across certain housing types and regions requires further validation through ongoing audits and future REUS studies.

Going forward the Terasen Utilities will continue to develop this proposed end use methodology across each of their service territories and will conduct additional research to complement the 2008 REUS data and further validate the methodology results. The Utilities will also evaluate a similar approach for commercial customer classes as end use data for such customer groups become available. The Utilities intend to conduct additional research[6] to address current knowledge gaps to consider the impact of new and disruptive technology on energy consumption and GHG reductions. The results of this research will allow the Utilities to vary their input assumptions and analyze a wider range of end-use characteristics and alternative customer energy choices.

[6] HOT 2XP and HOT 2000 are energy modelling software available from NRCan that the Terasen Utilities are currently using to model a range of energy comparisons in each of their service regions

Energy Usage Assumptions
for a Multi-family Residential Building:
(100 Unit Condominium Example – Lower Mainland)

The following is a summary of a theoretical energy use evaluation for a four-storey one-hundred unit condominium building in the Lower Mainland. Thermal Energy usage and GHG emissions have been compared for a typical baseline energy delivered today (electricity for space heating, Natural gas for water heating and make up air unit) against a geo-exchange system using natural gas as the back-up energy source. The following assumptions were made for the evaluation:

- Study building is a 4 storey 100 suite condominium
- Total residential floor area: 100,000 sq. ft.
- Space heating load per suite: 11 Btuh/sq. ft.
- Pool heating demand is zero
- Percent of heating by gas fireplace is zero
- Commercial floor space area is zero
- Gas MUA[1] efficiency: 80%
- Domestic water heater(DWH) and space heating gas boiler efficiency: 75%
- GSHP annual COP[2] for space and MUA heating: 3.8
- GSHP annual COP for DHW pre-heating: 3.3
- Air to water heat pump and WSHP annual EER[3]: 13 Btu/h-W
- GSHP annual EER: 16 Btu/h-W
- Degree days: 2925
- Annual DWH demand per suite: 11 GJ's
- Percentage of space heating by GSHP: 85%
- Percentage of MUA heating by GSHP: 85%
- Percentage of DWH heating by GSHP: 70%
- GHG emissions for gas equip: 0.0510 tonnes per GJ
- GHG emissions for electrical equip: 0.0061 tonnes per GJ

[1] MUA – make up air
[2] COP – coefficient of performance
[3] Energy Efficiency Ratio

Table 1 indicates energy use and corresponding GHG emissions for a 100 unit condominium that uses electricity for space heating and natural gas for hot water and make up air. For this analysis these values represent the baseline for thermal energy delivery. For comparison purposes, electricity and natural gas energy units are shown in GJ's.

Table 1: Annual Natural Gas and Electric Energy Requirements and Corresponding GHG Emissions for 100 unit Condo in LML

Type of Energy Use	Annual Natural Gas Use	Annual Electrical Energy Use	Total Annual Energy Use: Gas + Elect.	Annual GHG Emissions (Tonnes of CO_2)
Electric Baseboard	-	1814 GJ	1814 GJ	11
DWH	1467 GJ	-	1467 GJ	75
MUA	1313 GJ	-	1313 GJ	67
Total Energy Use & GHG Emissions	2780 GJ	1814 GJ	4594 GJ	153

Table 2 indicates the thermal energy delivered to the same 100 unit condominium as described above using Ground Source heat Pump. Discrete standalone systems such as geo-exchange systems typically serve about 85% of the required space heating and MUA demand as well as 70% of domestic hot water need. The remaining energy is complimented by both natural gas and electricity.

Table 2: Annual Natural Gas and Electric Energy Requirements and Corresponding GHG Emissions for 100-unit Condominium with GSHP and Natural Gas for DHW and MUA Heating

Type of Energy Use	Annual Natural Gas Use	Annual Electrical Energy Use	Total Annual Energy Use: Gas + Elect.	Annual GHG Emissions (Tonnes of CO_2)
GSHP	281 GJ	592 GJ	873 GJ	18
DWH	367 GJ	237 GJ	604 GJ	20
MUA	175 GJ	238 GJ	413 GJ	10
Total Energy Use & GHG Emissions	823 GJ	1067 GJ	1890 GJ	48

SURVEY CONDUCTED FOR TERASEN

Alternative Energy in British Columbia

Methodology

From July 31 to August 2, 2009 Angus Reid Strategies conducted an online survey among a randomly selected, representative sample of 802 adult residents of British Columbia who are Angus Reid Forum panelists. The margin of error—which measures sampling variability—is +/- 3.5%, 19 times out of 20. The results have been statistically weighted according to the most current education, age, gender and region Census data to ensure a sample representative of the entire adult population of British Columbia. Discrepancies in or between totals are due to rounding.

Objectives

The objectives of the study were:

- To find out the level of awareness and knowledge of alternative energy sources – Solar, Biomass, District Heating Systems and Ground Source Heat Pump, among BC residents.

- To find out whether BC residents who are aware of alternative energy sources are willing to pay extra to incorporate an alternative energy source in their home.

- Tto find out whether customers expect Terasen Gas to provide these alternative energy sources.

Familiarity with Alternative Energy or Green Energy

Base: 802 respondents in BC

- One-in-four BC residents (26%) are very familiar with the terms Alternative Energy or Green Energy, and two-in-four (43%) are familiar with them. Only five per cent have never heard of the terms, and 26 per cent have heard of them, but are not familiar with them.

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- The highest level of familiarity with Alternative Energy or Green Energy (those who responded very familiar or familiar) is in Vancouver Island (76%), among people aged 18 to 34 (72%), those living in households earning more than $100,000 a year (76%) and university graduates (75%).

Awareness of Energy Sources

Base: 773 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy

- All respondents (100%) are aware of solar energy (60% very aware, 40% aware).
- Three-in-four respondents (77%) are aware of ground source heat pumps (31% very aware, 46% aware).

- Half of respondents (53%) are aware of biomass energy (13% very aware, 40% aware).

- Two-in-five respondents (39%) are aware of district heating systems (7% very aware, 33% aware).

- Awareness of ground source heat pumps increases with household income (from 69% among those living in households earning less than $50,000 a year, to 86% among those living in households earning more than $100,000 a year) and age (from 69% for respondents aged 18 to 34, to 84% for those over the age of 55).

- Awareness of biomass energy increases with household income (from 52% among those living in households earning less than $50,000 a year, to 62% among those living in households earning more than $100,000 a year) and education (from 49% for respondents with a high school education or less, to 60% for university graduates).

- Awareness of district heating systems increases with household income (from 32% among those living in households earning less than $50,000 a year, to 46% among those living in households earning more than $100,000 a year) and age (from 32% for respondents aged 18 to 34, to 43% for those over the age of 55).

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Knowledge of Energy Sources and Technology

Base: 773 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy

- 39% of respondents claim to be extremely knowledgeable or very knowledgeable of solar energy; 55% are somewhat knowledgeable.
- 19% of respondents claim to be extremely knowledgeable or very knowledgeable of ground source heat pumps; 41% are somewhat knowledgeable.
- 8% of respondents claim to be extremely knowledgeable or very knowledgeable of biomass energy; 28% are somewhat knowledgeable.
- 6% of respondents claim to be extremely knowledgeable or very knowledgeable of district heating systems; 23% are somewhat knowledgeable.

Willingness to Incorporate an Alternative Energy Source

Base: 773 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy

- Two-thirds of BC residents (69%) are extremely or very willing to incorporate an alternative energy source (Solar, Biomass, District Heating Systems or Ground Source Heat Pumps) if they were buying or building a new home or renovating an existing home.

- The respondents who voiced the highest level of willingness to incorporate an alternative energy source reside in the BC Southern Interior (74%), are older than 55 years of age (74%), and live in households earning less than $50,000 a year (73%).

Paying Extra for a Home that Uses an Alternative Energy Source

Base: 745 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy, and who are extremely willing, very willing, or somewhat willing to incorporate an alternative energy source into their home.

- One-in-five BC residents who would incorporate alternative energy to their home (19%) would be willing to pay up to 10% extra for a home that uses an alternative energy source. Two-in-five (41%) would pay up to 5% extra, and 28% would pay from 1% to 2% extra for such a home.

Terasen Gas Providing Alternative Energy Sources

Base: 773 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy

- One-third of respondents (33%) believe Terasen Gas should provide these alternative energy sources (Solar, Biomass, District Heating Systems or Ground Source Heat Pumps) for customers, while 19 per cent disagree, 35 per cent answer "maybe", and 12 per cent are undecided.

- Respondents in Metro Vancouver (36%) and the BC Southern Interior (also 36%) are the most willing to say "Yes" to Terasen providing alternative energy to consumers, along with respondents aged 18 to 34 (46%).

Energy Efficiency Improvements

Base: 802 respondents in BC

- One-third of BC residents (34%) have undertaken an energy efficiency improvement in their homes, while one-in-four (24%) are planning to do so. Three-in-ten (29%) have not undertaken any energy efficiency improvements and do not intend to do so.

- Respondents over the age of 55 (40%) were more likely than younger BC residents to have undertaken an energy efficiency improvement, while those living in households earning less than $50,000 a year (34%) were more likely to reject the idea.

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Conclusions

- Awareness of alternative energy technologies varies highly by technology – solar power and heat pumps have near universal awareness, while nearly half of the population is unaware of Biomass and over 60% are unaware of district heating systems.

- Despite the apparent low level of knowledge of specific sources (less than 10% for both biomass and district heating systems), many British Columbians are clearly willing to try alternative energy.

- People in the BC Southern Interior, those over the age of 55, and those in the lowest income bracket are particularly supportive of alternative energy (more than 70% are willing to incorporate it in their homes). However, those in lower income households are less likely to undertake energy efficiency improvements.

- A third of BC residents want Terasen Gas to offer alternative energy to its customers, with the strongest support coming from respondents aged 18 to 34.

- One-in-five BC residents would consent to paying an extra 10% for a home that incorporates alternative energy, and just 13 per cent would not pay more at all.

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Angus Reid Strategies is a full-service polling and market research firm which is a leader in the use of the Internet and rich media technology to collect high-quality, in-depth insights for a wide array of clients. Dr. Angus Reid and the Angus Reid Strategies team are pioneers in online research methodologies, and have been conducting online surveys since 1995.

Angus Reid Strategies, along with its sister company, Vision Critical, is now the largest Canadian-owned market research enterprise. In addition to its five offices in Canada—located in Vancouver, Calgary, Regina, Toronto, and Montreal—the firm also has offices in San Francisco, Chicago, New York, London, Paris and Sydney. Its team of specialists provides solutions across every type and sector of research, and currently serves over 200 international clients.

Angus Reid Strategies polls are conducted using the Angus Reid Forum (www.angusreidforum.com), Springboard America (www.springboardamerica.com) and Springboard UK (www.springboarduk.com) online panels, which are recruited via an industry-leading process that incorporates a randomized, widespread invitation approach and a triple opt-in screening procedure. The panels are maintained through state-of-the-art sampling techniques and frequent verifications of personal identity, contact information, and demographic characteristics. These premier online survey platforms present respondents with highly visual, interactive, and engaging surveys, ensuring that panel members provide thoughtful and reliable responses.

Angus Reid Strategies, the only public opinion firm to exclusively use online methods to follow the views of the electorate during the 2008 federal campaign, offered the most accurate prediction of the results of Canada's 40th election.
http://angusreidstrategies.com/uploads/pages/pdfs/2008.10.15_Election.pdf

Since 2006, Angus Reid Strategies has covered eight provincial elections in Canada—more than any other pollster in the country—and the results have accurately predicted the outcome of each of these democratic processes.
http://angusreidstrategies.com/uploads/pages/pdfs/2008.03.28_Anniversary_1.pdf
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More information on the way Angus Reid Strategies conducts public opinion research can be found at http://www.angusreidstrategies.com/uploads/pages/pdfs/ARS.ARF.WP.pdf

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For more information, please contact the researcher listed in the footnote.

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Per Vehicle Use Assumptions for NGV Demand Scenarios

The TGI Utilities used market information acquired from pilot projects, project engineering work, industry partners, and suppliers to develop reasonable estimates on vehicle consumption for each vehicle segment in the target market. We believe industry data is more representative of the target market that is being pursued. Under all three scenarios, the NGV consumption in GJ is determined by applying a conversion factor – referred to as Diesel Litre Equivalents[1] ("DLE") – to the fuel consumption data for conventional fuel vehicles. This conversion creates a comparable assessment of the energy use from diesel versus natural gas. These values are held constant for each of the scenarios. Table 1 shows the natural gas consumption as well as the average distance travelled for vehicles in each of the categories.

Table 1: Natural Gas Consumption and Average Distance Travelled for B.C. Vehicle Categories

Category	Scenario Assumptions	
	Annual Consumption per Unit (GJ)	Total Annual Average # of Kms
Passenger Cars	100	17,500
Light Duty Trucks	170	20,000
Medium Duty Trucks	450	20,000
Heavy Vocational Trucks	800	40,000
Heavy Duty Trucks	2,500	300,000
Buses*	1,840	70,000
Marine	92,000	65,000

* Does not include school buses

Each industry study or pilot project from which these assumptions were developed is described below. If not notated, the scenario assumption is based on data from Natural Resource of Canada Office of Energy Efficiency (2007)[2].

[1] The conversion is based on energy content values published in the NRCan GHGenius model. (Diesel at 38.653 MJ/litre – yields conversion factor of 25.9).

[2] Natural Resources Canada, Office of Energy Efficiency, 2007: http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/handbook_tran_ca.cfm?attr=0

Passenger Cars - The passenger car estimate of 100 GJ/unit/year is based on TGI's actual experience operating the Honda GX in fleet service.

Light Duty Trucks - In 2009, TGI had consumption of 75,046 GJ from light duty truck customers. TGI assumes 170 GJ/unit/year as a baseline based on experience with its own commercial fleet vehicles.

Medium Duty Trucks - A fleet of medium duty trucks (delivery vans) consumed 15,000 GJ from a Surrey based CNG station in 2009. These 30 vans used approximately 450 GJ/unit/year.

Heavy Vocational Trucks - TGI is presently exploring project proposals with Waste Management Inc. and the City of Port Coquitlam. These projects involve heavy duty vocational trucks that run on CNG. The aforementioned parties have communicated that their trucks use approximately 800 GJ/unit/year over an average total distance of 40,000 kilometers per vehicle per year.

Heavy Duty Trucks - In 2009, TGI, Westport Innovations, and IMW Industries combined with Wastech Services Ltd. for a pilot project where solid waste was transported using heavy duty LNG garbage trucks, from Greater Vancouver to the Cache Creek landfill[3]. The results of the study concluded that the NGV trucks would consume up to 9,500 GJ/unit/year over an average total distance of 389,000 kilometers per vehicle per year. TGI is also exploring a potential project with the City of Vancouver's fleet of waste transfer vehicles. Each vehicle consumes approximately 1,500 GJ per year, operating approximately 80,000 kms per year. It is expected that fleets with high mileage are more likely to convert to LNG operation as the operating cost savings will be greater for these fleets. Given the range of potential fuel consumption and the propensity for LNG customers to be high mileage applications, TGI believes that 2,500 GJ/truck/year is a reasonable estimate for average heavy duty vehicle fuel consumption.

Buses - TGI collaborated with BC Transit to conduct a study of the potential for NGV transit buses in BC. From data provided by BC Transit, TGI has learned that transit buses consumed around 1,840 GJ/unit/year and travel an average total distance of 70,000 kilometers per vehicle per year.

Marine - Based on conversations with BC Ferries, TGI has learned that the Queen of Capilano travels its Horseshoe Bay (Vancouver) to Snug Cove (Bowen Island) route using 2.4 million litres of diesel per year. This route has an estimated total distance of approximately 65,000 kms per vessel per year[4]. Unit energy consumption can be calculated by converting litres of diesel to GJ, which results in approximately 92,000

[3] http://www.wastech.ca/uploads/media%20material/090507_Wastech_LNG_mediapkg.pdf
[4] Based on 16 round trips of 11.2 kms, 365 days/year. http://www.westcoastferries.ca/routes.html

GJ/unit/year. The Queen of Capilano is a typical mid-size ferry vessel which TGI is targeting.

Biogas Market Study

General Summary

Date: April 2010

Presented to • Présenté à
Terasen Gas

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Contents

At TNS, we know that being successful in today's dynamic global environment requires more understanding, clearer direction and greater certainty than ever before. While accurate information is the foundation of our business, we focus our expertise, services and resources to give you greater insight into your customers' behavior and needs.

Our integrated, consultative approach reveals answers beyond the obvious, so you understand what is happening today – and what will happen tomorrow. That is what sets TNS apart.

Thank you for allowing us to explore your business needs. We hope you will continue to trust TNS to provide the insight you need to sharpen your competitive edge.

1.0 Foreword

1.1 Background

There are two major shifts impacting the energy sector: (1) the marketplace is becoming more diverse and competitive, and (2) environmental issues appear to be increasingly relevant to energy consumers. Being faced with these challenges, Terasen Gas (Terasen) has been repositioning itself as an integrated energy provider that can be both competitive and environmentally friendly (i.e., by minimizing the environmental impact of its activities).

As part of this new positioning, Terasen is exploring renewable energy initiatives that offer customers green energy choices based on biomethane fuels (biogas).

1.1.1 Study Objectives

TNS was commissioned to help Terasen better understand the potential residential and commercial markets for biogas, its market drivers, and sensitivities to different price points for a biogas program. Specifically, the research objectives for both the residential and commercial markets were to measure:

1. Market interest, the potential target market and market size for a renewable energy program (biogas);
2. Market interest and the potential target market for a carbon offset program;
3. Market drivers;
4. Price points and factors affecting price points; and,
5. Customer perceptions of different product offerings.

1.2 Methodological Overview

Data was gathered from both BC households and businesses using an online methodology. An online methodology was used to facilitate a discrete choice analysis – which cannot be done on the telephone or through a mail survey. A discrete choice exercise prompts respondents to choose between a series of program alternatives that trade-off different features. From their choices, it is possible to indirectly measure which elements weigh more heavily in respondents' energy decisions.

1.2.1 Residential Study

An online survey with 1,401 respondents was conducted between November 23 and December 4, 2009 among BC residents (18 years of age or older) using TNS Canadian Facts' online panel. TNS online panels are comprised of households who volunteer to complete surveys from time to time.

A quota sample was used to ensure feedback from three distinct types of residential households:

- Terasen Gas customers (those who receive a gas bill directly from Terasen);
- Indirect customers (gas users who are not billed directly i.e., gas costs are included in strata fees or rent); and,
- Non gas users (those who do not use gas).

Non gas users were included in this study to get a full picture of the BC residential energy market.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential Terasen customer households, and not individuals.

1.2.2 Commercial Study

A business sample of over 26,000 customers was provided directly by Terasen Gas to TNS for the commercial study as TNS does not currently have a commercial online panel. Commercial customers were contacted initially by telephone and those which choose to participate were then emailed a link to the online survey.

A total of 500 online surveys were completed by business customers of Terasen between December 14, 2009 and January 22, 2010. A very similar questionnaire was used for both residential and business respondents to allow for comparison between the two groups.

The table below summarizes the final interview counts for both residential and business studies.

Sample Composition

	Actual Interviews	Proportion of Total
	#	%
Residential Study		
Terasen Gas customers (receive gas bill directly from Terasen)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don’t know their energy source	50	4%
Total Residential Interviews	1,401	100%
Business Study		
Total number of interviews	500	100%

2.0 Executive Summary

Both the residential and commercial customer studies produced results that lead to several similar recommendations for Terasen. This is not all that surprising since commercial organizations are managed by individuals (or residents), whose philosophies, attitudes and personal experiences become part of an organization's corporate culture.

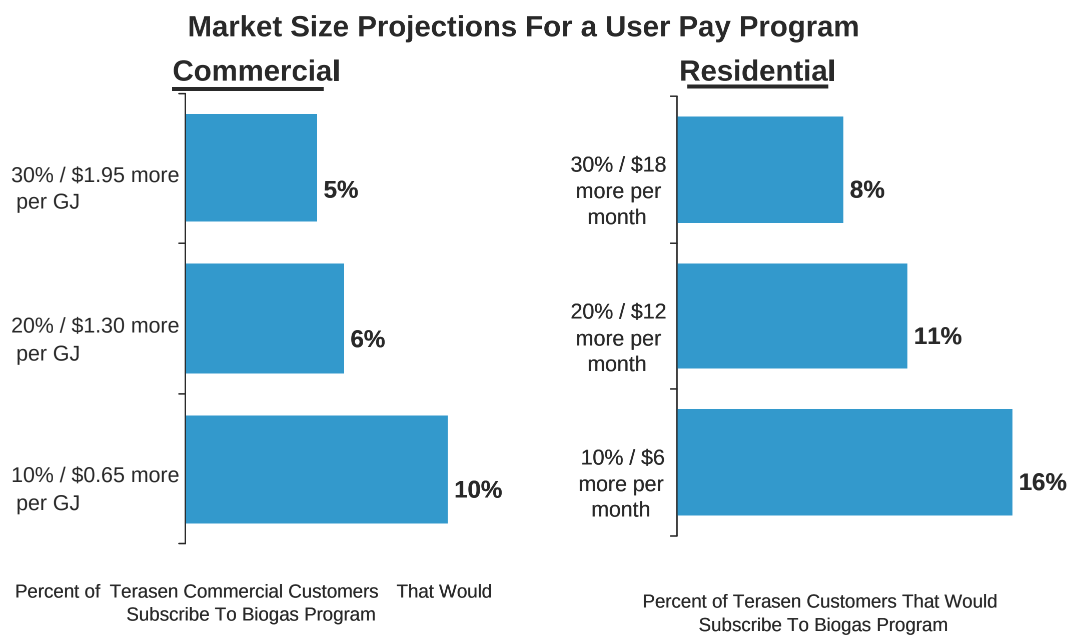
In this study, two different types of initiatives were presented to respondents: a biogas program and a carbon offset program. Both stakeholder groups confirmed, at different points in the study that they are more likely to sign up for a biogas program than a carbon offset program. If Terasen were to bring only one of these options to market, we would recommend a biogas program since it would yield a larger market share.

Specifically, if all factors today remained constant (e.g., energy prices remain unchanged), 56% of Terasen's residential customers and 47% of commercial customers would commit to a biogas program on the benefits of the fuel alone. However, this potential market declines if the cost of the program impacts their gas bill. Price is one of the main barriers to a biogas program for many residents and businesses – it prevents many residents and commercial customers from committing to the program. The survey explored pricing levels for a universal price increase as well as a program customers can sign up for at a premium. There was strong support for moderate price increases between 0.5% - 3% for a biogas program where costs were borne by all customers. For a user-pay program, 16% of residential customers and 10% of commercial customers indicated they would enrol in a biogas program at a 10% increase to their current commodity price. Market share projections at various pricing levels for a user-pay biogas program are detailed later in this summary.

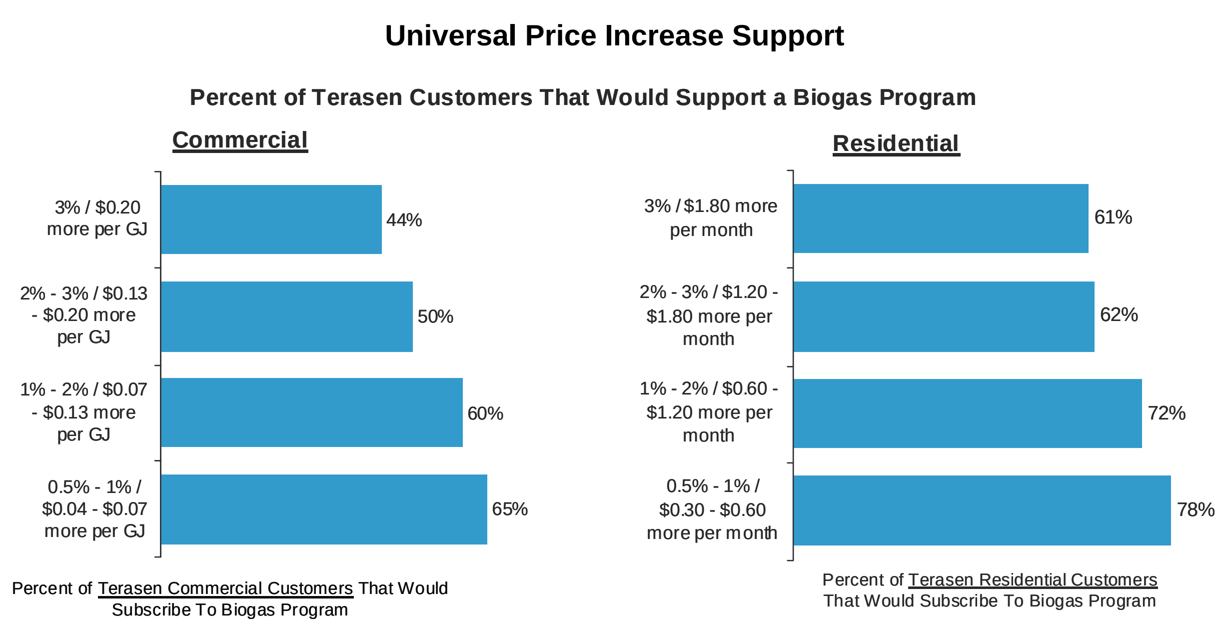
Finally, residential customers are more enthusiastic about committing to a biogas program than commercial customers. There appears to be greater hesitation on the part of commercial customers. This fact, coupled with the larger residential market, makes residential households a potentially more lucrative segment to target (than commercial customers).

2.1 Market Projections

Using projections obtained through both the survey data and Terasen's customer data, it is possible to get an idea of what proportion of commercial customers and residential households might potentially subscribe to a biogas program at different price points. The chart below summarizes the results obtained from residential and commercial customers. It shows initial enrolment rates and drop-off levels at key price points for incremental price increases to the commodity rate for a user pay program as well as support for universal price increase levels for a biogas program where costs are borne by all customers.



Above figures are based on share of preference (DCM analysis) with corresponding GHG reduction levels associated with each price point.



Above figures are based on a direct line of questioning.

2.2 Pricing

The decision on the optimal price point to introduce a biogas program will depend on Terasen's goals. If it is…

- To maximize household and business involvement, introduce universal price increases borne by all customers;
- To maximize household and customer involvement with premium pricing, increase current prices by 10%;
- To balance Greenhouse Gas (GHG) reductions with premium pricing; increase current prices by 20%; and,
- To offer higher GHG reductions, higher price increases of 30% (or more) will be required.

2.3 Communications Campaign

Enrolment rates for a biogas program will also depend on the strengths of Terasen's communications and marketing. As illustrated in the trade-off analysis, any marketing campaign must demonstrate the environmental benefits of biogas and how it reduces greenhouse gas emissions. The level of greenhouse gas reductions associated with a program has a strong influence on which programs customers will support. This is particularly true for customers that indicate they wish to see a higher GHG reduction for programs with a higher premium.

With respect to the potential target segments for a biogas program, we recommend designing a communications strategy aimed at residential households first. On the residential side Terasen should target:

- Customers who have "green" tendencies;
- Higher educated and higher income households (they tend to be less price sensitive);
- Females (they tend to be more green); and,
- Those who have participated in past energy savings programs.

For commercial customers, a more universal communications strategy should be applied, which demonstrate environmental value for the price paid. Businesses want to see how much of their carbon footprint is being reduced, for each extra dollar that they spend. In this regard, Terasen might consider updating its current billing template to incorporate this additional information.

For Detailed Results – See General Summary

3.0 General Summary

3.1 Residential Findings

As noted previously, Terasen sought input on environmentally-friendly energy initiatives, namely a biogas program and a carbon offset program, from BC residents and commercial customers. This section summarizes results obtained from BC residents (n=1,401). The results gathered among commercial customers are summarized in the next section.

3.1.1 Opinions On Biogas

Approximately two-thirds of residents will support Terasen if the organization opts to invest in biogas projects and an equal number feel Terasen should offer a biogas program for customers. While roughly two-thirds of residents endorse a Terasen biogas program, 56% would sign up for a biogas program. Motivations for enrolment vary, with top reasons among potential enrollees being: providing for future generations; preserving nature, and doing the right thing.

Should Terasen Be Investing In Biogas

	Total
Base: Total respondents	(1,401)
Yes (8-10)	67%
Maybe (4-7)	27%
No (1-3)	2%
Decline	4%

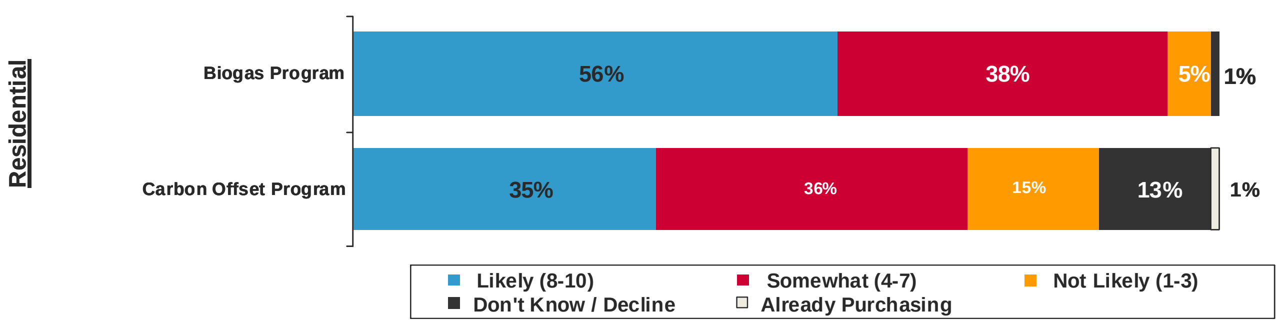
Should Terasen Offer A Biogas Program

	Total
Base: Total respondents	(1,401)
Yes (8-10)	65%
Maybe (4-7)	30%
No (1-3)	1%
Decline	4%

3.1.2. Opinions On Carbon Offsets

Residents were also asked about their support for carbon offsetting programs. While approximately half of residents are aware of carbon offsets, just three-in-ten (31%) indicated likelihood of purchasing them to offset their personal natural gas use. When asked to choose which program they would prefer to see Terasen introduce, residents chose a biogas program over carbon offsets by a three-to-one margin.

Likelihood To Sign Up For Terasen Offered Programs:

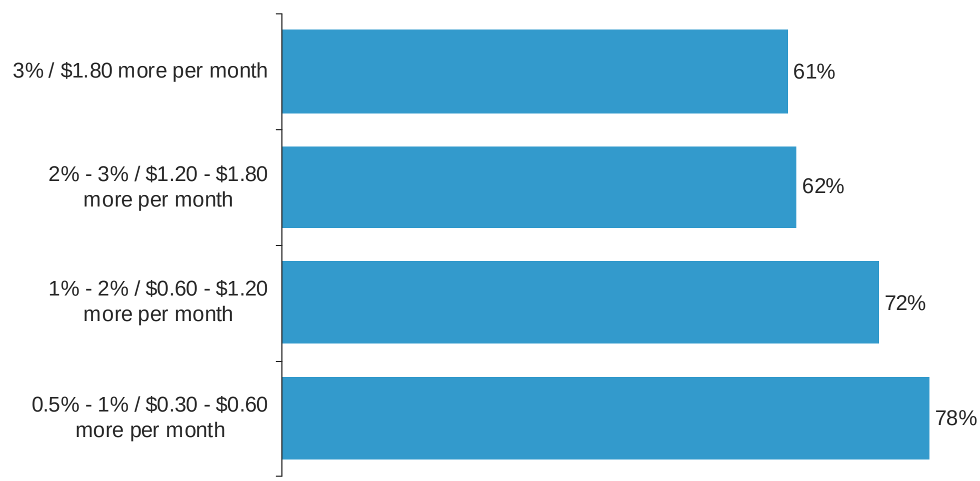


3.1.3 Price For Biogas

Residents who expressed an interest in signing up for a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums for only those who enroll in the program. There was a stronger preference voiced for a universal price increase (47%), compared to a biogas program people can sign up for at a premium (26%), but a considerable number of respondents indicated they did not know which one they would prefer (27%).

As consumers will see the impact of a biogas program on their gas bill, it was also important to explore what size of increase residents might be comfortable with. All respondents were asked universal price increase questions directly in order to explore what level of price increase they would support (up to 3%). This information was supplemented with indirect questions through the discrete choice exercise to explore higher pricing increases (10% to 30% commodity price increase for a program customers can sign up for at a premium).

As expected, support for the biogas program decreases as the potential impact on the consumers' gas bill rises. Seventy-eight percent of residential customers indicated they would support a universal price increase of 0.5% to 1%. However, slightly fewer (62%) would still support a universal price increase of up to 3%, revealing there is a substantial proportion of the market willing to financially support biogas initiatives.



Percent of Terasen Residential Customers Who Would Support Program at Specified Price Point

3.1.4 Preferred Program Options

The Discrete Choice Model (DCM)[1] included in the survey also indirectly measures which features weighed more heavily in residential energy choices. The discrete choice exercise explored the relationship between the price of renewable energy options (measuring steeper price increases of 10%-30%) and greenhouse gas reductions. These results confirm that price is an important consideration, but can be counteracted by the prospect of disproportionately higher greenhouse gas reductions (e.g., 20% price increase yielding a 30% GHG reduction is as popular as an option that sees a 10% cost increase and a 10% reduction).

In the following simulation, we compare three different biogas programs that respondents can choose from (a program with a 10% GHG reduction and 10% price premium; a program with a 20% GHG reduction and a 20% price increase; or a program with a 30% GHG reduction and 30% price increase). The program with a 10% GHG reduction and 10% price increase is preferred by 46% of residential customers who said they would sign up for a biogas program. The two choices with the higher price increases were preferred by a smaller proportion of residential customers.

[1] A Discrete Choice Model (DCM) asks respondents to choose between a series of program alternatives that trade-off on different features. From their choices, a DCM model is able to indirectly measure which elements weighed more heavily on a respondent's selections. In this study, a model was built on three dimensions – (1) type of energy initiative, (2) percent reduction in GHG levels, and (3) effect on monthly gas bill. Thirty-six possible pairings of choice sets were built into the questionnaire, based on different permutations of the three dimensions. Each respondent was presented with a random set of 16 pairings and asked to select the scenario they preferred in each pairing.

Choice #1

Renewable energy program

10% price increase

10% GHG reductions

Choice #2

Renewable energy program

20% price increase

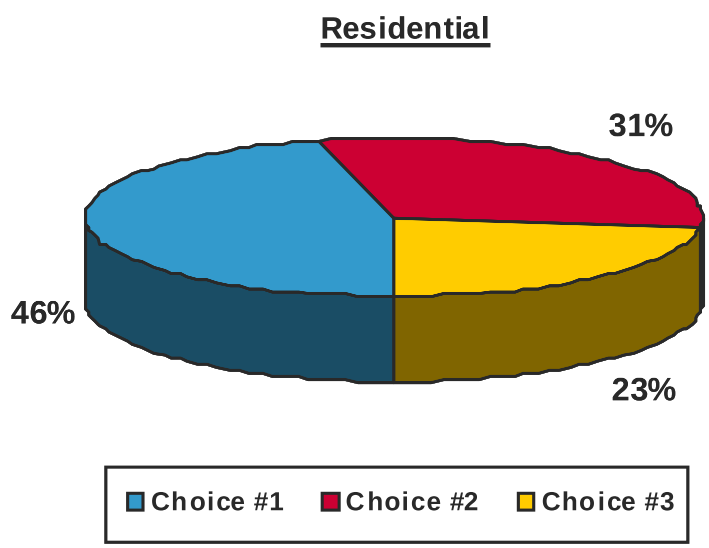
20% GHG reductions

Choice #3

Renewable energy program

30% price increase

30% GHG reductions



Base: The 56% of Terasen customers who are likely to sign up for a biogas program (n=445)

3.1.5 Estimating Market Potential

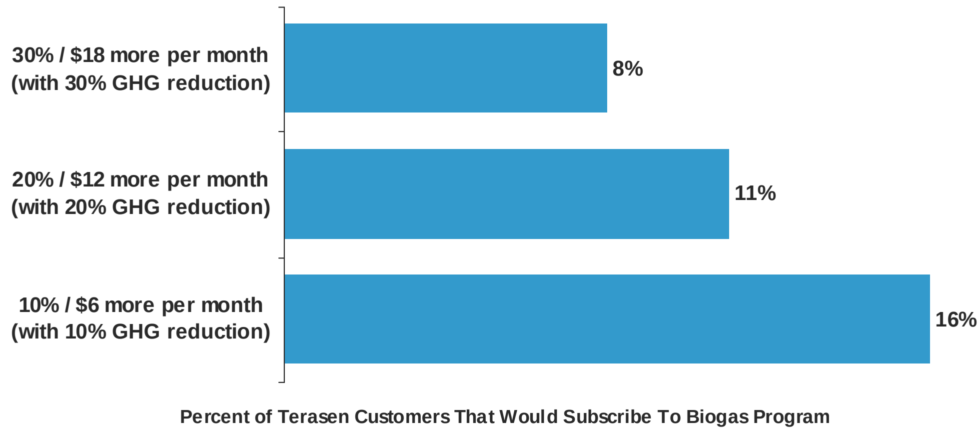
Using the survey data, it was possible to generate rough estimates of potential market share for a biogas program. The projected market estimates were calculated based solely on what respondents told us. Knowing this, we would caution that these figures should be considered best case estimates. The reason for caution is two-fold:

- People do not always do what they say – we often fall short of our intended goals; and,
- Respondents sometimes have the tendency to provide answers in a manner consistent with how they perceive we want them to answer – in this case, to sign up for a biogas program because it has positive impacts on our environment.

The market projections in this section of the report are based on Terasen customers who receive a gas bill directly from Terasen as these customers are accessible to Terasen and have the greatest control over whether or not their households would sign up for such program. We excluded all other residents from this analysis.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential Terasen customer households, and not individuals.

The chart on the following page uses the market projections to get an estimate of what proportion of residential households might potentially subscribe to a biogas program province-wide at different price points. Among Terasen residential customers, 56% indicated a willingness to sign up for a biogas program if there are no cost implications. As soon as the biogas initiative has cost implications on the residential gas bill, enrollment levels begin to drop off. It is estimated that 16% of those interested in signing up for a biogas program would support a user pay premium of 10% or $6 per month – if it results in a 10% reduction in GHG levels.



3.1.6 Profile Of Potential Biogas Market

Generally speaking, the demographic profile of residents voicing support for biogas initiatives does not differ greatly from that of residents who are not supportive. However, education and income appear to be two factors that differ between supporters from detractors. This information may help Terasen direct marketing efforts towards receptive customers.

3.2 Commercial Findings

The following section highlights results gathered among Terasen's commercial customer base (n=500).

3.2.1 Opinions On Biogas

Similar to support levels found among BC residents, 67% of commercial customers will support Terasen if the organization opts to invest in biogas projects. Support for Terasen offering a biogas program is higher among commercial customers than among residents (71% support the initiative compared to 65% of residents). Similar to the pattern seen among residents, support for a biogas program is strong, but a smaller proportion (47%) indicates they would actually enroll in it. Motivations for enrolment among commercial customers vary, with primary reasons being: doing the right thing; providing for future generations, and preserving nature.

Should Terasen Be Investing In Biogas

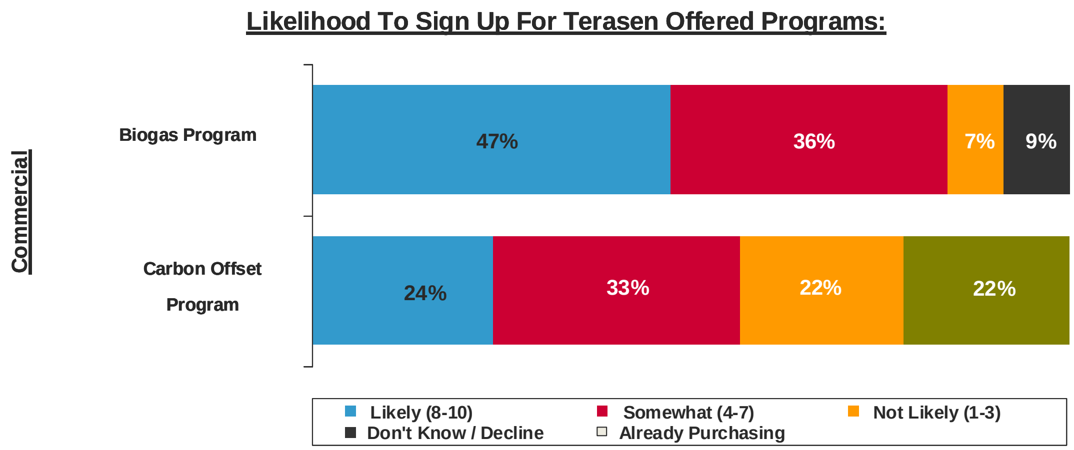
	Total
Base: Total respondents	(500)
Yes (8-10)	67%
Maybe (4-7)	23%
No (1-3)	3%
Decline	7%

Should Terasen Offer A Biogas Program

	Total
Base: Total respondents	(500)
Yes (8-10)	71%
Maybe (4-7)	22%
No (1-3)	2%
Decline	5%

3.2.2 Opinions On Carbon Offsets

Commercial customers are more aware of about carbon offsets than residents (66% awareness versus 50% among residents). Despite higher awareness levels, just 24% indicated likelihood of purchasing them to offset their business' natural gas use. When asked which program they would prefer to see Terasen introduce, commercial customers chose a biogas program over carbon offsets by a three-to-one margin, mirroring the residential findings.

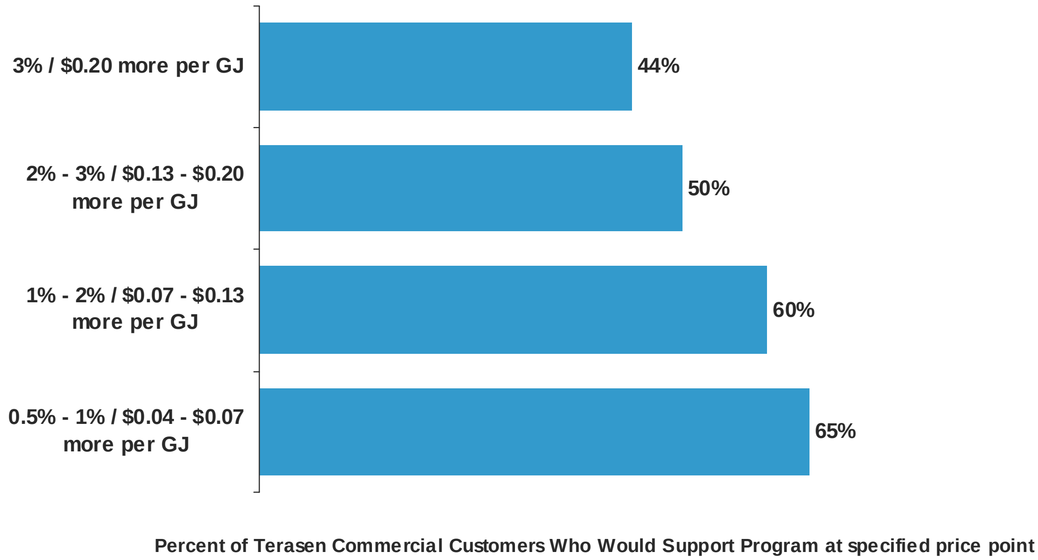


3.2.3 Price For Biogas

As with residents, commercial customers interested in a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums only for those who enroll in the program. Unlike residents who were unable to provide a conclusive assessment of funding options, commercial customers came out strongly in support of a universal price increase (supported by 60% of commercial respondents). Nineteen percent supported a premium price increase and 21% said they did not know.

It was also important to explore what size of increase commercial customers would be comfortable with for a universal price increase versus a voluntary program. As with the residential surveys, this information was gathered through a *direct* question about support at different price points (up to a 3% commodity price increase for a universal price increase) and *indirectly* through the discrete choice exercise (for 10% to 30% commodity price increase for a program customers can sign up for).

Overall, commercial customers are much more apprehensive than residential customers when it comes to supporting a biogas program when there are cost implications. Half of commercial customers would support this concept if it meant their gas bill would increase by up to 3%.



3.2.4 Preferred Program Options

The Discrete Choice Model (DCM) included in the survey also indirectly measured which features weighed more heavily in commercial customers' energy choices. The discrete choice exercise explored the relationship between the price of renewable energy options and greenhouse gas reductions. Consistent with the residential findings, these results confirm that price is an important consideration, but can be counteracted by greenhouse gas reductions proportionally larger than price increases (e.g., 20% price increase yielding a 30% GHG reduction is as popular as an option that sees a 10% cost increase and a 10% reduction). Indeed, results show commercial customers are particularly concerned about reducing GHG levels. However, like with residential customers, commercial customers also prefer the option of a 10% GHG reduction and a 10% price increase, among the three options presented in the DCM simulation on the following page.

Choice #1

Renewable energy program

10% price increase

10% GHG reductions

Choice #2

Renewable energy program

20% price increase

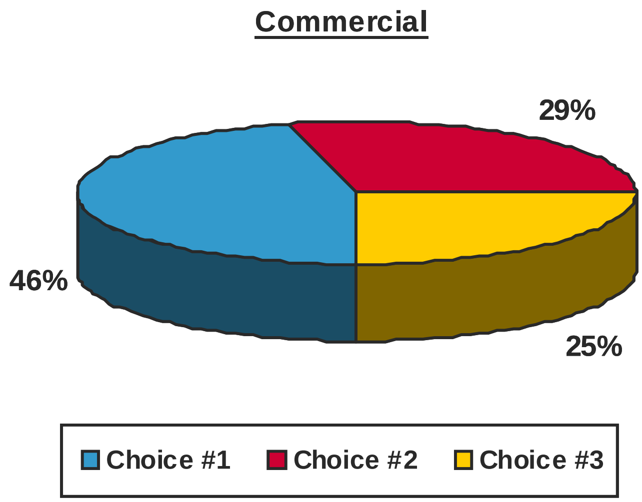
20% GHG reductions

Choice #3

Renewable energy program

30% price increase

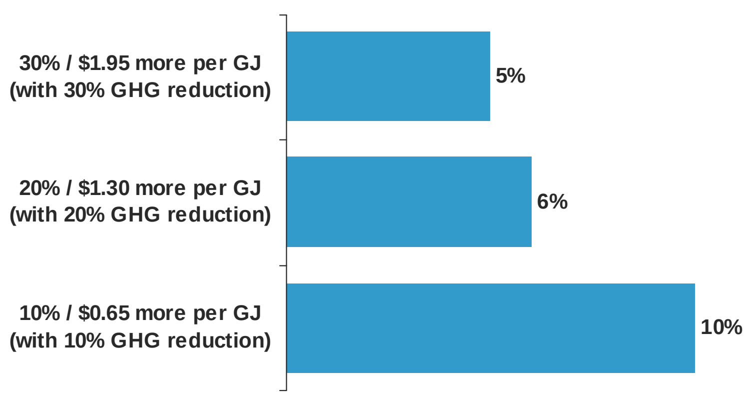
30% GHG reductions



Base: The 47% of Terasen commercial customers Who Are Likely To Sign Up For A Biogas Program (n=237)

3.2.5 Estimating Market Potential

The chart below uses market projections to develop an estimate of what proportion of businesses might potentially subscribe to a biogas program across the province. As noted earlier, 47% of commercial customers indicate willingness to sign up for a biogas program if there are no cost implications. As soon as the biogas initiative has cost implications on the gas bill, enrollment levels begin to drop off. It is estimated that 10% of those interested in signing up for a biogas program would support a user pay premium of 10% or $0.65 more per GJ – if it results in a 10% reduction in GHG levels.



Percent of Terasen Commerical Customers That Would Subscribe To Biogas Program

3.2.6 Profile Of Potential Biogas Market

The commercial customers most likely to enroll in the biogas program include those who have participated in past energy saving programs, single location organizations (as opposed to those with multiple locations), and those who express concern for the environment.

Technical Appendix

Overview

A total of 1,401 online interviews were conducted between November 23 and December 4, 2009 with a sample of British Columbia residents. In addition to these residential interviews, 500 interviews were conducted with commercial customers of Terasen from December 14, 2009 to January 22, 2010. Results obtained from this survey provide valuable insights into understanding perceptions of Terasen and feature preferences for a renewable biogas program.

Sample Frame And Design

The samples used in this survey were drawn from two different sources. TNS' Canadian online adult panel was used to intercept BC residents. All BC communities were sampled. A quota cell design was used for this survey to ensure that a specific sampling level was achieved with respect to Terasen's own customers and non-customers. The number of completed interviews for each quota group are outlined below.

Sample Composition

	Actual Interviews	Proportion of Total
	#	%
Residential Study		
Terasen Gas customers (receive gas bill directly from Terasen)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don't know their energy source	50	4%
Total Residential Interviews	1,401	100%
Business Study		
Total number of interviews	500	100%

Respondent Selection And Qualification

Respondents were selected differently for the two studies. On the residential side, respondents were randomly selected from TNS' online panel. This includes both gas users and non-users. On the commercial survey, respondents were restricted to Terasen customers and drawn randomly from Terasen's database. On both studies, respondents who work for a utility, gas marketer, the media, a research or advertising firm, were screened out of the study.

Questionnaire Development

The residential questionnaire was developed by TNS Canadian Facts in consultation with Terasen Gas. Prior to the start of interviewing, a pretest was conducted over the first weekend of field to ensure the workability of the questionnaire and to finalize question sequencing.

The commercial questionnaire is almost identical to the residential questionnaire with slight modifications.

Data Collection

Residential respondents were recruited from TNS' online panels and directed to the survey site to complete the survey.

Commercial respondents were recruited from Terasen's customer database. These respondents were first approached by phone. Once their participation was secured, they were asked for their email addresses, so that the survey link could be sent to them. The survey had to be conducted online because the DCM analysis contained in this research project requires an online interface with respondents.

Survey Margin Of Error

Please note that margins of error apply to randomly selected samples. Residential panel samples are self selected and therefore the following margin of error figures are presented as a guide for readers. The overall sampling error for 1,401 total residential interviews at the 95% confidence level is approximately ± 2.6%. For example, if 50% of all residents surveyed stated that they have heard of carbon offsets, then we can be sure, nine times out of ten, that if the entire population had been interviewed, the proportion would lie between 47.8% and 52.2%.

When a segment of the entire data is analyzed, the sampling error increases. For example, the overall sampling error for data based on 200 interviews at the 95% confidence level is approximately ± 7.0%. In this case, using the scenario where respondents surveyed state that they would purchase a carbon offset, then we can be sure, nine times out of ten, that this proportion would lie between 43.0% and 57.0%.

The commercial survey results are subject to margins of error. At the 95% confidence level, the margin of error for the 500 commercial customers' interviews is ± 4.4%.

A copy of the invitation and questionnaire used in this survey are appended to this report.

Appendix C

2009-2011 EEC PROGRAM DETAILS

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

2009-2011 EEC Program Details

Residential Programs

Program Name	Year	Description
ENERGY STAR Heating Systems Upgrade	2009	$250 incentive for upgrading heating system to ENERGY STAR rated appliance
ENERGY STAR Heating Systems Upgrade-LiveSmart BC	2009	$250 incentive for upgrading heating system to ENERGY STAR rated appliance as part of LiveSmart BC incentive portfolio
EnerChoice Fireplace	2009-2010	2009: $50 dealer incentive to promote and educate customers about Energy Efficient Fireplaces 2010: $150 direct to consumer incentive to educate customers about Energy Efficient Fireplaces
Domestic Hot Water 62% ENERGY STAR Tanks	2010-2011	$50 consumer incentive and $50 contractor incentive to prepare the market for new provincial regulations
Furnace early retirement program	2011	Re-educate market about high efficiency furnaces and urge customers to upgrade early—approval pending
Furnace Service Campaign "Give your furnace some TLC"	2010-2011	$25 grocery store gift card given to customers who service their furnace in order to educate the market about the importance of appliance maintenance and create opportunities to upgrade appliances for efficiency
.80 EF Domestic Hot Water (DHW) Technologies Pilot and Program	2010-2011	Validate energy savings on new 0.8 EF technologies, market research, and develop installation protocols for market transformation

Joint Initiatives

Program Name	Year	Description
EcoEnergy Home Energy Assessments (D-Visits) through LiveSmart BC	2009-2010	$75 incentive to cover the partial cost of Home Energy Assessment provided by an NRCan certified Home Energy Advisor
Utility Partner Home Renovation Program - LiveSmart BC	2010-2011	Utility partners (Terasen, BC Hydro and FortisBC) are covering the partial cost of LiveSmart BC building envelope incentives including insulation, draft-proofing and windows
Tier 3 ENERGY STAR Washer and Dryer Rebate with Fortis BC- six week pilot	2009-2010	$50 incentive for Tier 3 washers and dryers in Fortis BC service territory and campaign to promote efficient laundry practices
Water Savers Pilot (Low Flow Shower Heads)	2010	Shower Head change-out pilot with FortisBC at two communities in 2010 with plans to expand based on energy savings data
Home Weatherization Pilot	2010	City of Vancouver, Terasen, BC Hydro and Embers providing weatherization training to social enterprise, conduct energy modeling on about 40 homes, and develop protocols in support of home weatherization industry
Energy Specialists	2010-2011	Energy specialist focused on natural gas savings to complement BC Hydro's Energy Manager

Fuel Switching

Program Name	Year	Description
Oil/propane to natural gas conversions – Energy Star Heating System upgrade	2010-2011	$1000 incentive for upgrading oil or propane primary heating system to ENERGY STAR heating systems

Commercial Programs

Program Name	Year	Description
Efficient Boiler Program	2009-2011	Rebate program for high efficiency commercial boilers >300 MBH input
Light Commercial ENERGY STAR Boiler Program	2009-2011	Rebate program for high efficiency commercial boilers <300 MBH input
Energy Assessment Program	2009-2011	No charge energy use assessment of commercial facilities
Efficient Commercial Water Heater Program	2010-2011	Rebate program for high efficiency (84%) commercial water heating appliances
Process Heat Assessment	2010- 2011	Rebate program targeted at manufacturing processes
Commercial Cooking Program	2010-2011	Rebate program targeted at commercial cooking appliances
Commissioning Program	2010-2011	Incentive program to capture energy savings via building commissioning
Victoria Spray 'N' Save Program	2010	Free provision and install of low flow pre rinse spray valve. Partnership with BC Hydro.
Custom Design Pilot	2010-2011	Incentive program to encourage energy savings via otherwise difficult to incent measures
Fireplace Timer Pilot	2010-2011	Pilot program to evaluate the effectiveness of time of operation control devices on decorative fireplaces

Communications, Education, & Outreach

Program Name	Year	Description
Print and Online Publications	2009-2011	Energy conservation education promoted through bill inserts, newspaper and magazine ads, trade show guides, newsletters, directories, and terasengas.com
Trade shows and events	2009-2011	Participated in residential home shows and commercial trade shows to reach customers and educate on energy efficiency rebate programs
Students and Schools Outreach: Destination Conservation	2009-2011	K-12 program educating students and teachers about energy conservation and efficiency and providing them with curricula and support materials
Students and Schools Outreach: Beyond Recycling	2009-2011	K-7 program educating students and teachers about energy conservation in West and East Kootenays
Students and Schools Outreach: BC Green Games	2009-2011	K-12 competition for students to submit digital entries of their environmental projects
Students and Schools Outreach: School Assembly Presentations	2009-2011	K-7 school assembly presentations on energy conservation through interactive competitions
Energy Champion Program	2009-2011	Educate children and youth about energy conservation through behavioural changes, using regional sports team events
Team Terasen Outreach	2009-2011	Outreach group delivering the Company's EEC message by connecting with customers at community events and festivals.
Ethnic Outreach	2010-2011	Targeted in-language (Punjabi and Mandarin) online and print media, and event attendance, to reach key ethnic markets

Employee Education	2010-2011	Energy conservation education and action program focused on engaging employees in the company
Behaviour Change Pilot Program	2010-2011	Municipalities pilot: staff engagement plan for five municipal customers (including Vancouver Coastal Health)
Behaviour Change Pilot Program (Commercial and Institutional Pilot)	2010-2011	Online tool where users can learn about energy conservation, and make social commitments towards behavioural changes and GHG emission reduction actions.

Conservation for Affordable Housing

Program Name	Year	Description
Meridian Village	2009-2011	A partnership to upgrade 124 furnaces in a Metro Vancouver owned social housing complex
LiveSmart Carry Over	2009	Energy efficiency retrofits in five affordable housing complexes as part of the completion of LEAP
Energy Conservation for Affordable Housing Forum	2009-2011	A collaborative forum to strengthen the energy conservation for affordable housing in BC
BC Affordable Energy Conservation Strategy (study)	2010-2011	A province-wide strategy paper for addressing conservation for affordable housing
Strategic Energy Management Plan (study)	2009-2010	A study focused specifically on the non-profit housing sector in BC
CHF BC Energy Performance Housing Inventory (study)	2010-2011	A building inventory of co-operative housing in BC
REnEW	2010-2011	Capacity building program focused on increasing the supply of energy efficiency assessors and installers

Energy Saving Kits (ESK)	2010-2011	Partnership with BC Hydro for basic self-install energy efficient measures
Energy Conservation Assistance Program	2010-2011	Partnership with BC Hydro for more robust direct-install energy efficiency measures

Appendix D

CAPITAL PLANS AND PROJECTS

TGI 5-YEAR CAPITAL PLAN

1 PREAMBLE

TGI has segmented its 5 Year Capital Plans as follows:

Regular Capital Plan

- Category A – Customer Driven Capital – Mains, Services and Meters
- Category B – Transmission and Distribution Systems Integrity and Reliability
- Category C – All Other Plant

Major Capital Plan

- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital is defined as forecast Capital Expenditures that are under $5 million (excluding AFUDC) and have been categorized into Category A, B and C. This category excludes Capitalized Overheads and Allowance for funds used during construction ("AFUDC").

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. Typically, major capital projects for TGI in excess of $5 million have required a CPCN.

TGI's 5 Year Capital Plans for the period 2010 to 2014 are presented to provide additional background and context for the Resource Plan. These Capital Plans are not included for the purposes of approval by the BCUC in its review of the TGI Resource Plan, since TGI believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. TGI's 2010-2011 Revenue Requirements Application included detailed capital expenditures that were reviewed and approved by Commission on November 26, 2009 by Order G-141-09. Consistent with past practice, TGI continues to believe that the appropriate forum for review of its Capital Expenditures is in its Revenue Requirements Application proceedings.

As TGI's 5 Year Regular Capital Plan and Major Capital Plans include all planned capital expenditures, TGI believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the Utilities Commission Act.

TGI has endeavoured to provide a comprehensive 5 Year Capital Plan as part of its submission. However, the projects and figures contained herein are subject to change and may be revised to reflect additional information as part of the Company's next Revenue Requirements Application filing, which is anticipated in 2011.

2 5 YEAR REGULAR CAPITAL PLAN

The following table identifies the cost projections for regular capital expenditures from 2010-2014. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

- Category A – Customer Driven Capital – Mains, Services and Meters
    - Mains
    - Services
    - New Meters and Meters Recalled
- Category B – Transmission and Distribution Systems Integrity and Reliability
    - Transmission
    - Distribution
- Category C – All Other Plant
    - IT Projects
    - Non IT Projects
- Contributions In Aid of Construction

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 1 identifies the cost projections for regular capital expenditures in 2010-2014.

Table 1: Forecast of Regular Capital Expenditures ('000's)

	2010 Projection	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast
Category A					
Mains	8,807	9,306	9,227	9,696	9,889
Services	14,722	15,940	16,025	17,018	17,531
Meters (Customer Additions)	1,588	1,728	1,727	1,830	1,888
Replacement Customer Meters (Allocation)	18,178	19,055	19,814	15,772	21,061
	43,295	**46,029**	**46,793**	**44,316**	**50,369**
Category B					
Transmission Plant	9,546	8,663	9,922	9,703	8,725
Distribution Plant	7,900	6,250	8,370	6,250	6,250
	17,446	**14,913**	**18,292**	**15,953**	**14,975**
Category C					
IT	16,000	16,000	18,000	18,000	18,000
Non-IT	16,770	16,655	14,026	15,380	15,444
	32,770	**32,655**	**32,026**	**33,380**	**33,444**
Contributions in Aid of Construction	**(4,024)**	**(3,929)**	**(3,800)**	**(3,869)**	**(3,916)**
Total Regular Capital	**89,487**	**89,669**	**93,311**	**89,781**	**94,872**

Figures exclude AFUDC and Capitalized Overheads

3 5 YEAR MAJOR CAPITAL PLAN

3.1 Major Capital Projects that do not require a CPCN

Table 2 identifies the cost projections for major capital projects that are included in Regular Capital but are not subject to CPCN applications for the period 2010-2014.

Table 2: Forecast of Major Capital Projects not requiring a CPCN ('000's)

Project Description	Project Category	2010 Forecast	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast
Transmission Plant						
Drawdown Compressor	System Modifications	-	2,000	-	-	-
Gas Fired Vapourizer	System Modifications	-	1,620	-	-	-
Tilbury LNG Facility Second Boil-Off Compressor	System Modifications	-	500	1,000	-	-
		-	4,120	1,000	-	-
Distribution Plant						
152nd Street Surrey, IP line	Capacity Shortfall	1,000	-	-	-	-
36th Ave., Delta, IP line	Capacity Shortfall	-	-	1,211	-	-
72nd St., Delta, IP line	Capacity Shortfall	-	-	1,800	-	-
		1,000	-	3,011	-	-
IT						
SAP Unicode/Database Conversion	Upgrade/Enhancement	1,050	-	-	-	-
Transmission Maintenaace System	Upgrade/Enhancement	1,494	108	657	612	-
Desktop/Laptop Refresh	Upgrade/Enhancement	-	-	-	2,150	1,350
Microsoft Windows 7	Upgrade/Enhancement	-	-	-	1,500	200
Disaster Recovery	Upgrade/Enhancement	1,200	1,800	-	-	-
BC One Call Improvements	Upgrade/Enhancement	1,393	1,611	389		
		5,137	3,519	1,046	4,262	1,550
Non-IT						
No projects Identified		-	-	-	-	-
Total Major Projects		**6,137**	**7,639**	**5,057**	**4,262**	**1,550**

3.1.1 DISTRIBUTION PLANT – 152ND STREET IP, SURREY

As a result of a decision by the City of Surrey to construct a road overpass at 152nd Street and Colebrook Road it is necessary that Terasen relocate, through replacement, 780 metres of its existing 323mm O.D. steel intermediate pressure pipeline to facilitate the construction. This project is currently planned to be constructed and in service by October, 2010. The estimated cost of this project is $1 million (excluding AFUDC).

3.1.2 DISTRIBUTION PLANT – 36TH AVENUE IP, DELTA

This project is currently planned to be constructed in 2012. It consists of a 1.75 km loop of 323mm O.D. pipeline along 36th Ave in Delta. The estimated cost of this project is $1.2 million (excluding AFUDC) and is expected to be in service in 2012. This system improvement is required to increase capacity to offset aggressive long term load growth projections that have been provided by the greenhouses in the Delta area. This system improvement will only be installed if the affected greenhouses convert some, or all, of their interruptible load to firm load.

3.1.3 DISTRIBUTION PLANT - 72ND STREET IP, DELTA

This project is currently planned to be constructed in 2012. It consists of a 2.6 km loop of 323mm O.D. pipeline operating at 1,200 kPa. The estimated cost of this project is $1.8 million (excluding AFUDC) and is expected to be in service in 2012.

This system improvement is required to accommodate load growth to greenhouses in the Delta area. This system improvement will only be installed if the affected greenhouses convert some, or all, of their interruptible load to firm load. With this loop installed greenhouses would not need to be curtailed until colder ambient temperatures are reached.

3.1.4 TRANSMISSION & DISTRIBUTION PLANT - GATEWAY PROJECT

The Gateway Program was established by the Province of British Columbia in response to the impact of growing regional congestion, and to improve the movement of people, goods and transit throughout Greater Vancouver. The Gateway Program is sponsored by the Ministry of Transportation ("MoT") and includes three components:

- Port Mann / Highway 1 Project includes twinning the Port Mann Bridge, upgrading interchanges and improving access and safety on Highway 1 from Vancouver to Langley.
- The South Fraser Perimeter Road Project is a new four-lane, 80 km/h route along the south side of the Fraser River extending from Deltaport Way in southwest Delta to the Golden Ears Bridge connector road in Surrey/Langley.
- The North Fraser Perimeter Road Project is a set of improvements on existing roads to provide an efficient, continuous route from New Westminster to Maple Ridge.

The highway projects and segments are in various stages of planning, design and construction. The planned highway construction and upgrades will impact the Terasen Gas Transmission and Distribution systems along the highway corridors. Since 2006, the MoT and Terasen Gas have been involved in ongoing discussions regarding this project and as a result Terasen Gas has developed detailed designs for modification to the gas system. Many of these modifications are now complete. Based upon the current plans and available information, Terasen Gas projects that total system modifications will cost approximately $28.2 million (excluding AFUDC). Since TGI has an agreement with the MoT that allows for 100% cost recovery if certain requirements are satisfied, no spending has been shown in Table 2 above.

3.1.5 TRANSMISSION PLANT - PIPELINE DRAWDOWN COMPRESSOR

During maintenance and emergency repair on transmission pressure pipelines, the natural gas isolated in the work section is required to be removed. The trapped natural gas could be directly vented to the atmosphere. To reduce the amount of gas venting, expensive stopple fittings and bypasses can be installed to shorten the length of the isolated pipe section. Alternatively, mobile drawdown compressor(s) can be deployed to ``drawdown`` the trapped natural gas from the isolated pipeline section to neighboring pressurized sections of the pipeline thus minimizing greenhouse gas emission to the atmosphere. With typical small compressors available in the construction industry, this drawdown procedure for a large diameter high pressure pipeline would take a long time (measured in days) to complete.

In 2010, TGI will define the functionality requirements and specifications of the large horsepower mobile drawdown compressor suitable for Terasen Gas pipelines on Vancouver Island, Lower Mainland and Interior BC. The acquisition and commissioning of the compressor are expected to take place in 2011. The cost of the compressor is yet to be determined but is estimated in the range of $1 to 2 million.

3.1.6 TRANSMISSION PLANT - GAS FIRED PORTABLE LNG VAPORIZER

To provide large volume supply of natural gas to avoid service curtailment or outage to customers during planned or emergency work to transmission or distribution systems, the use of a large volume gas fired portable LNG vaporizer and the corresponding 10,000 USG LNG road tanker is required. The LNG road tanker is being purchased in 2010 while the specialized gas fired portable LNG vaporizer, estimated at a cost of $1.6 million, is expected to be specified, acquired and commissioned in 2011.

3.1.7 TRANSMISSION PLANT - TILBURY LNG FACILITY – SECOND BOIL-OFF COMPRESSOR

During normal operation to provide overpressure protection, the boil-off compressor at the Tilbury LNG Facility would remove the excessive boil-off gas from the 600 MMscf LNG storage and inject the gas back into the connecting transmission pipeline system. During maintenance of this single existing boil-off compressor, overpressure protection of the LNG storage tank would depend on the relief valves on the LNG tank to vent the boil-off gas directly into the atmosphere. To eliminate this one source of GHG emission into the atmosphere from the Tilbury LNG Facility, the addition of a second boil-off compressor at an estimated cost of $1.5 million is planned to be operational by 2012.

3.1.8 IT CAPITAL – SAP UNICODE / DATABASE CONVERSION PROJECT

The SAP Unicode / Database Conversion initiative is intended to convert the SAP ECC 6.0 and SAP BW environments to Unicode and convert the ECC 6.0 database Oracle to MS-SQL Server. Unicode is an industry standard which enables, among other things, seamless communications between software platforms. SAP is encouraging customers to adopt the Unicode standard within their SAP environment as this will be a requirement in future releases of the product, and is a requirement today for some SAP solutions. Since the process of converting database platforms is similar to converting the environment to Unicode, we are also moving from an Oracle to MS-SQL Server database environment which will likely provide annual maintenance cost savings.

The total cost of the project (excluding AFUDC) is $1.1 million with expenditures of $1.05 million in 2010. It commenced in November 2009 and is expected to be complete in late 2010.

3.1.9 IT CAPITAL – TRANSMISSION MAINTENANCE SYSTEM PROJECT

The Transmission Maintenance System project is intended to replace existing Transmission asset maintenance IT tools with SAP-Plant Maintenance. This project has been split up into two phases: The first addresses the replacement of the existing IT systems with SAP-PM; and the second phase is to address workforce mobilization (access to IT systems in the field).

This initiative is required to meet the long term needs of Transmission Asset management and Operations by:

- Enhancing the ability to demonstrate regulatory compliance and due diligence as well as to manage risks due to increasing stakeholders expectations;
- Delivering an integrated set of process, people, and technology to address deficiencies of the current IT tools;
- Supporting maintenance management for the new Mt. Hayes LNG Facility;
- Providing a key building block for Transmission to execute its strategies and initiatives presented in the 2010-2011 Revenue Requirement Application;
- Enabling Transmission to capture knowledge currently residing with soon-to-retire field personnel.

3.1.10 IT CAPITAL – DESKTOP / LAPTOP REFRESH PROJECT

The Desktop Refresh program was started in 2005. The objective of the program is to replace aging desktop and laptop computers in the Terasen environment. The life expectancy of desktop and laptop computers is 4 years. The program resulted in the refresh of aging desktop computers, laptop computers, and monitors. The program allows the evaluation of new hardware and monitor standards and ensures the optimal, cost-effective hardware equipment that meets all immediate and long-term business requirements. It also provides an opportunity to standardize desktop and laptop software images. LCD panels have an 8 year refresh cycle.

A desktop refresh program is essential to ensure that the personal computer replacement process can be standardized and coordinated as well as ensuring that business operations and services will not be impacted with unexpected hardware failures.

The 2009 desktop refresh project was started in Q1 2009 and will be completed by September 2010. The refreshed desktops and laptops from 2009 and 2010 will reach their 4 year cycle in 2013 and 2014 respectively and will be required to be refreshed. The estimated project costs will be $2.15M in 2013 and $1.35M in 2014.

3.1.11 IT CAPITAL – MICROSOFT WINDOWS 7 UPGRADE PROJECT

An operating system (OS) is the infrastructure software component of a computer system; it is responsible for the management and coordination of activities and the sharing of the limited resources of the computer. The operating system acts as a host for applications that are running on the machine. As a host, one of the purposes of an operating system is to handle the details of the operation of the hardware.

Terasen is currently in the process of upgrading its entire desktop and laptop operating system to Microsoft Vista Enterprise. Windows Vista will be moving from mainstream support to extended support in 2012. Windows 7 was released in late 2009. The earliest most organizations will start deployment will be mid 2011 or 2012 as it will take time for product stabilization. Terasen will evaluate the OS (Windows 7 or follow-on release) for a 2013 and 2014 OS upgrade project when Microsoft releases the OS product cycle. Upgrading the operating system with the 2013 and 2014 Desktop Refresh projects will minimize deployment costs and minimize interruptions. The estimated project costs will be $1.5M in 2013 and $0.2M in 2014.

3.1.12 IT CAPITAL – DISASTER RECOVERY PROJECT

The Disaster Recovery project will provide an alternate location to run critical business systems in the event of disaster impacting our server room at Surrey Operations.

We currently have four applications that could be accessed in the event of a disaster at Surrey today; AM/FM, SAP (for reporting only), WINS and Nucleus. The remainder of applications would need to be restored from tape on new hardware.

This scenario provides a risk to Terasen Gas as it may take up to 4 to 6 months to procure hardware and have the Surrey operations datacenter restored.

Telus delivered their technical design for the disaster recovery plan at the end of 2009. The design is based on the results of an IBM disaster recovery study and interviews with the business groups. The design, although scalable, is designed to support 240 simultaneous users as defined in the IBM document. These 240 users were identified as the minimal staffing required to support the business during a disaster. These users would access their applications via CITRIX from any location with an internet connected PC.

This project will start in Q2 of 2010 and complete Q2 of 2011. The cost is approximately $3 to $3.5 million over two years.

3.1.13 IT CAPITAL – BC ONE CALL IMPROVEMENTS

Terasen Gas has a legal obligation to provide accurate and timely information to the public about the location of Terasen's gas mains and services as outlined within the BC Gas Safety Regulation. The number of BC One Call tickets has steadily increased over the years and it is expected that this number will continue to increase. This project will be undertaken to handle the increasing number of tickets, which will involve process, technology, and data improvements. The estimated cost is approximately $3 to $3.5 million. It is estimated to start in June 2010 with a completion date of early 2012.

3.2 Major Capital Projects that require a CPCN

Table 3 identifies the cost projections for major capital projects subject to CPCN applications for 2010-2014.

Table 3: Forecast of Major Capital Projects subject to CPCN Applications ('000's)

Project Description	2010 Projection	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast
Approved CPCN's & Deferral Accounts					
Fraser River SBSA Rehabilitation	20,187	6,817			
Customer Care Enhancement	26,931	66,431	7,829		
Tilbury Land Purchase	15,889	-			
	63,007	**73,248**	**7,829**	**-**	**-**
Anticipated CPCN's & Deferral Accounts					
Okanagan Reinforcement	1,000	1,000			
Kootenay River Crossing	1,100	6,300			
Huntingdon Station Bypass	200	12,000			
	2,300	**19,300**	**-**	**-**	**-**
Total CPCN's & Deferral Accounts	**65,307**	**92,548**	**7,829**	**-**	**-**

3.2.1 APPROVED CPCN – FRASER RIVER SOUTH BANK SOUTH ARM ("SBSA") CROSSING

In March 2009, the Commission issued Order No. C-2-09 approving the CPCN to replace two horizontal directional drilled natural gas transmission pipeline crossings at the South Arm of the Fraser River between Delta and Richmond. The project is now estimated to be completed by August 31, 2011 at a total cost of approximately $35.1 million (excluding AFUDC) excluding any contractor claims and considering no further required dike improvements. For further details, please refer to the quarterly progress reports filed with the Commission.

3.2.2 APPROVED CPCN – CUSTOMER CARE ENHANCEMENT

The Company will implement a strategic sourcing model to deliver customer care services and replace the business process outsourcing model that has been in use since 2002. The key change that this model brings is that Terasen Gas will repatriate full control over all customer care business processes and invest in its own assets required for their functioning.

The implementation of the strategic sourcing model, through the Customer Care Enhancement project, involves the following elements:

- In-source and own the customer information system and IT support functions; and
- In-source and manage the call centre and the routine back-office billing functions.

The total cost of the Customer Care Enhancement project is estimated to be $115.5 million including AFUDC. The project received approval by the BCUC in February 2010 by Order C-1-10. The project began implementation in March 2010 and is expected to be completed in early 2012, with customer care services provided directly by the Company starting on January 1, 2012.

3.2.3 APPROVED CPCN - TILBURY LAND PROPERTY PURCHASE

The Company filed a CPCN application for the acquisition of the property, consisting of 22.8 acres of freehold land, at a cost close to $16 million, immediately adjacent to the Tilbury LNG Facility to obtain greater control of the use of the property and to act as a buffer to help ensure continued compliance with mandatory safety standards for the continued operation of the Tilbury LNG Facility,. The Commission issued Order No G-28-10 and subsequently issued Order No C-2-10 granting a CPCN approval for the property purchase, which closed in June 2010.

3.2.4 ANTICIPATED CPCN - KOOTENAY RIVER CROSSING (SHOREACRE) UPGRADE

The NPS 8 Kootenay River aerial crossing located near Shoreacres in the Kootenays is part of the Interior Transmission System. Constructed in 1957 with deteriorating components and combined with slope instability concern at one terminus, the aerial crossing is near the end of its useful structural life. The Company has examined alternatives to replace the existing aerial crossing including a new crossing beneath the river by mean of a horizontal directional drill (HDD). The HDD is recommended as the preferred alternative in terms of capital cost, ratepayer impact, and non-financial factors including safety, environmental, land, First Nations, operational impacts, system capacity and aesthetics.

The Project, scheduled to be in service by the mid- 2011, has an estimated capital cost of approximately $8.3 million including AFUDC and involves:

- Decommissioning of the existing NPS 8 Kootenay River aerial crossing,
- Abandonment of approximately 625 m of NPS 6 transmission pressure pipe, and
- Replacement of both with approximately 880 m of new NPS 6 transmission pressure pipe beneath the Kootenay River to be installed using HDD technology.

3.2.5 ANTICIPATED CPCN – HUNTINGDON CONTROL STATION BYPASS

The Company's Huntingdon Control Station is a custody transfer interconnection with Spectra's Westcoast Pipeline located at the Huntingdon-Sumas trading hub. This is the single midstream gas supply receipt point for the Coastal Transmission System and the TGVI transmission System, providing natural gas supply to well over 682,000 residential, commercial, and industrial customers in the Lower Mainland, Sunshine Coast, and on Vancouver Island. With the Huntingdon Control Station located at a critical gas supply hub for the Pacific Northwest Region, it is exposed to single point failure, collateral damage from potential failure of neighboring midstream facilities subject to security risks.

With the potentially high consequence from the failure of the Huntingdon Control Station, the Company intends to provide redundancy by the addition of a station bypass of the Huntingdon Control Station. The station bypass will consist of the addition of a new custody transfer interconnection with Spectra's Westcoast Pipeline immediately upstream (or north) of the current Huntingdon-Sumas interconnection, a new bypass pipeline, and a new pressure regulation and measurement station connecting to the Company's Coastal Transmission System shortly downstream of the current Huntingdon Control Station. In the event of a failure of the main Huntingdon Control Station, it is to be isolated with the activation of the station bypass. The station bypass would be an alternative to supply natural gas to customers in the Lower Mainland, Sunshine coast and on Vancouver Island.

The Company plans to submit a CPCN application in Q2 of 2011 for the installation of the station bypass, to be completed before the 2012/13 winter season. The early preliminary cost estimate for this Project is at $12 million.

3.2.6 ANTICIPATED CPCN – OKANAGAN REINFORCEMENT PROJECT

Based on the 2010 core market demand forecast, the Interior Transmission System is anticipated to face system capacity shortfall by 2017. However, with the potential new industrial load, for example if FortisBC proceeds with its gas fired peaking generation station in the

Okanagan as early as 2014 according to its filed Resource Plan, reinforcement of the ITS would be required to match the earlier load increase.

Three resource options are available: phased pipeline looping from Penticton towards Kelowna in conjunction with increased compression at Kitchener-B Compressor Station at a budgetary estimate of $42 million and $20 million respectively, Phased pipeline looping from Savona at a budgetary estimate of $30 million, or LNG peaking storage facility in North Okanagan at a budgetary estimate of $131 million. If the reinforcement is required by 2014, a CPCN application would need to be filed with the Commission as early as 2011.

TGVI 5-YEAR CAPITAL PLAN

1 PREAMBLE

TGVI is attaching its 5 Year Regular Capital Plan and 5 Year Major Capital Plan to the 2010 TGVI Resource Plan. In aggregate these two plans constitute the Company's 5 Year Capital Plans.

TGVI has segmented its 5 Year Capital Plans as follows:

Regular Capital Plan

- Category A – Customer Driven Capital – Mains, Services and Meters
- Category B – Transmission and Distribution Systems Integrity and Reliability
- Category C – All Other Plant

Major Capital Plan

- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital is defined as forecast Capital Expenditures that are under $5 million (excluding AFUDC) and have been categorized into Category A, B and C. This category excludes Capitalized Overheads and Allowance for funds used during construction ("AFUDC").

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. Typically, major capital projects for TGVI in excess of $5 million have required a CPCN.

TGVI's 5 Year Capital Plans for the period 2010 to 2014 are presented to provide additional background and context for the Resource Plan. These Capital Plans are not included for the purposes of approval by the BCUC in its review of the TGVI Resource Plan since TGVI believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. TGVI's 2010-2011 Revenue Requirements Application included detailed capital expenditures that were reviewed and approved by Commission on November 29, 2009 by Order No. G-140-09. Consistent with past practice, TGVI continues to believe that the appropriate forum for review of its Capital Expenditures is in its Revenue Requirements Application proceedings.

As TGVI's 5 Year Regular Capital Plan and Major Capital Plans include all planned capital expenditures, TGVI believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the Utilities Commission Act.

TGVI has endeavoured to provide a comprehensive 5 Year Capital Plan as part of its submission. However, the projects and figures contained herein are subject to change and may be revised to reflect additional information as part of the Company's next Revenue Requirements Application filing, which is anticipated in 2011.

2 5 YEAR REGULAR CAPITAL PLAN

The following table identifies the cost projections for regular capital expenditures from 2010-2014. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

- Category A – Customer Driven Capital – Mains, Services and Meters
    - Mains
    - Services
    - New Meters and Meters Recalled

- Category B – Transmission and Distribution Systems Integrity and Reliability
    - Transmission
    - Distribution

- Category C – All Other Plant
    - IT Projects
    - Non IT Projects

- Contributions In Aid of Construction

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 1 identifies the cost projections for regular capital expenditure in 2010-2014.

Table 1: Forecast of Regular Capital Expenditures ('000's)

	2010 Proposed	2011 Proposed	2012 Forecast	2013 Forecast	2014 Forecast
Category A					
Mains	2,725	2,966	3,099	3,257	3,414
Services	5,940	6,459	6,801	7,200	7,603
Meters (Customer Additions)	540	582	609	652	678
Replacement Customer Meters (Allocation)	1,492	1,496	1,562	1,239	1,825
	10,698	**11,503**	**12,070**	**12,348**	**13,520**
Category B					
Transmission Plant	5,045	7,868	7,091	7,483	9,081
Distribution Plant	1,520	2,315	2,895	1,645	1,295
	6,565	**10,183**	**9,986**	**9,128**	**10,376**
Category C					
IT	1,500	1,500	2,000	2,000	2,000
Non-IT	2,906	2,642	2,562	2,590	2,361
	4,406	**4,142**	**4,562**	**4,590**	**4,361**
Contributions in Aid of Construction					
CIAC	(442)	(448)	(452)	(456)	(460)
Total Regular Capital	**21,226**	**25,379**	**26,167**	**25,610**	**27,798**

Figures exclude AFUDC and Capitalized Overheads.

3 5 YEAR MAJOR CAPITAL PLAN

3.1 Major Capital Projects that do not require a CPCN

Table 2 identifies the cost projections for major capital projects not subject to CPCN applications for the period 2010-2014.

Table 2: Forecast of Major Capital Projects not requiring a CPCN ('000's)

Project Description	Project Category	2010 Forecast	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast
Transmission Plant						
Pipeline Relocation at Coquitlam River Dam	System Modifications	50	2,550	-	-	-
		50	2,550	-	-	-
Distribution Plant						
IP Pipeline System Improvement, Saanich	Capacity Shortfall	-	1,500	-	-	-
		-	1,500	-	-	-
IT						
No projects identified		-	-	-	-	-
		-	-	-	-	-
Non-IT						
No projects Identified		-	-	-	-	-
Total Major Projects		**50**	**4,050**	**-**	**-**	**-**

3.1.1 DISTRIBUTION PLANT – IP SYSTEM IMPROVEMENT, SAANICH

This project involves the installation of 1500 metres of 323mm O.D. steel intermediate pressure pipeline paralleling an existing intermediate pressure pipeline (i.e. a "loop"). This system improvement is required to support load growth in the area by ensuring that the required inlet pressures to our existing David Street and Begbie Street Stations are maintained. As part of our 20 year System Improvement Plan for Saanich, the project is currently planned for 2011 but is dependent upon the increase in load from Royal Jubilee Hospital. The estimated cost of this project is $1.5 million (excluding AFUDC) or approximately $1,000 per metre which is higher than average due to the urban environment.

3.1.2 TRANSMISSION PROJECT – TGVI PIPELINE RELOCATION AT COQUITLAM RIVER DAM

This project involves the re-alignment of the 323 mm O.D. TGVI Transmission System in the vicinity of the BC Hydro dam on the Coquitlam River. The old dam on which the existing pipeline is currently located is deemed not to be seismically acceptable. The pipeline is scheduled to be re-aligned in 2011 on the replacement dam already constructed but currently under load testing. The total estimated cost of this project is estimated at $2.6 million.

3.1.3 IT PROJECTS

IT projects for TGVI are determined as 10% of the total IT project costs allocated from TGI. For additional information, please refer to the TGI 5 Year Capital Plan in Appendix X.

3.2 Major Capital Projects that require a CPCN

Table 3 identifies the cost projections for major capital projects subject to CPCN applications for 2010-2014.

Table 3: Forecast of Major Capital Projects subject to CPCN Applications ('000's)

Project Description	2010 Projection	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast
Approved CPCN's & Deferral Accounts					
Squamish to Whistler Pipeline Project	2,800				
Customer Care Enhancement Project	3,026	7,464	880		
Mt. Hayes LNG Storage Plant	54,166	26,709			
	59,992	**34,173**	**880**	**-**	**-**
Anticipated CPCN's & Deferral Accounts					
Victoria Regional Office	530	8,276	2,100		
	530	**8,276**	**2,100**	**-**	**-**
Total CPCN's & Deferral Accounts	**60,522**	**42,449**	**2,980**	**-**	**-**

3.2.1 CPCN – SQUAMISH TO WHISTLER NATURAL GAS PIPELINE

TGVI filed an application with the Commission for a CPCN in December 2005 to construct a 50 kilometer natural gas pipeline from Squamish to Whistler. Concurrently, TGW filed an application with the Commission for a CPCN to convert its propane system to natural gas and enter into a transportation service agreement with TGVI. In June 2006, the Commission approved both applications in Order No. C-3-06.

Total pipeline construction costs were approved for $30.2 million (excluding AFUDC) in 2005 dollars with an annual inflation adjustment allowance. The pipeline project commenced construction in May 2007 and the pipeline was put into service (delivering natural gas) in April 2009. The propane conversion project started in May 2009 and was complete by August 2009. TGW has made a capital contribution to TGVI to mitigate the cost impact to TGVI customers. The capital contribution amount was $17.0 million, subject to adjustment once all costs of the pipeline have been finalized. For additional information or updates, please refer to the quarterly progress reports filed with the Commission.

3.2.2 CPCN – CUSTOMER CARE ENHANCEMENT PROJECT

IT projects for TGVI are determined as 10% of the total IT project costs allocated from TGI. For additional information, please refer to the TGI 5 Year Capital Plan in Appendix X.

3.2.3 CPCN – MOUNT HAYES LNG STORAGE PROJECT

TGVI filed an application with the Commission on June 5, 2007 seeking approval for the Mt. Hayes Storage Project, including construction and ownership of an LNG peak-shaving storage facility, at Mt. Hayes near Ladysmith, and various associated facilities to connect the LNG Storage Facility to TGVI's natural gas transmission system. The Application sought approval of a storage and delivery agreement between TGVI and TGI.

In November 2007, the Commission issued Order No. C-9-07 to grant conditional approval for the project and later confirmed in April 2008 that the conditions were met.

Total capital costs were approved for $193.3 million (excluding AFUDC) and is expected to be in-service for the winter 2011/12.

The LNG Storage Project will allow TGVI to provide both additional system capacity and a gas peaking resource for the benefit of its customers as well as provide storage and delivery services to TGI.

TGVI engaged a design-build contractor for the design, procurement and construction of the LNG Storage Facility and their work commenced on April 8, 2008. On-site construction is currently underway with planned completion and turn-over to TGVI in May 2011.

3.2.4 ANTICIPATED CPCN – VICTORIA REGIONAL OFFICE LAND PURCHASE AND BUILDING

TGVI's Victoria Regional office is a leased facility located at 320 Garbally Road consisting of approximately 26,000 sq. ft of office and warehouse space on 4 acres of land. The lease is scheduled to expire October 31, 2012. The site is no longer suitable based on size and location. There is an opportunity to relocate to a more suitable facility and reduce operating costs.

The unique requirements of a regional office for ratio of office, warehouse and yard space is not readily available on the market and would require the company to enter into lease build to suit option or purchase land and build. In comparing the cost model of a lease build to suit vs. purchase land/build, it TGVI's preference is to purchase the land and build the site.

TGVI anticipates that it will file a CPCN application for this project in Q3 of 2010 targeting an expected completion date of the project in the fall of 2012. Preliminary project costs are currently estimated to be approximately $10.9 million (excluding AFUDC).

TGW 5-YEAR CAPITAL PLAN

1 TGW 5 YEAR REGULAR CAPITAL PLAN

The following table identifies the cost projections for regular capital expenditures from 2010-2014. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

Regular Capital Plan

- Category A – Customer Driven Capital – Mains, Services and Meters
- Category B – Transmission and Distribution Systems Integrity and Reliability
- Category C – All Other Plant

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 1 identifies the cost projections for regular capital expenditures from 2010-2014.

Table 1: Forecast of Regular Capital Expenditures ('000's)

	2010 Forecast	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast
Category A					
Mains	51	35	37	47	56
Services	97	68	72	89	106
Meters (Customer Additions)	14	9	10	12	14
Replacement Customer Meters (Allocation)	27	27	27	27	27
	190	**139**	**147**	**174**	**203**
Category B					
Transmission Plant	-	-	-	-	-
Distribution Plant	10	-	-	-	-
	10	**-**	**-**	**-**	**-**
Category C					
IT	-	-	-	-	-
Non-IT	153	126	167	162	131
	391	**292**	**340**	**364**	**362**
Contributions In Aid of Construction					
CIAC	-	-	-	-	-
Total Regular Capital	**591**	**431**	**487**	**538**	**565**

Figures exclude AFUDC and Capitalized Overheads.

2 TGW 5 YEAR MAJOR CAPITAL PLAN

There are no anticipated major capital projects for the period of 2010-2014.

TGI FORT NELSON 5-YEAR CAPITAL PLAN

1 TGI FORT NELSON 5 YEAR REGULAR CAPITAL PLAN

The following table identifies the cost projections for regular capital expenditures from 2010-2014. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

Regular Capital Plan

- Category A – Customer Driven Capital – Mains, Services and Meters
- Category B – Transmission and Distribution Systems Integrity and Reliability
- Category C – All Other Plant

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 1 identifies the cost projections for regular capital expenditures from 2010-2014.

Table 1: Forecast of Regular Capital Expenditures ('000's)

	2010 Projection	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast
Category A					
New Customer Mains	12	11	8	8	8
New Customer Services	14	13	9	9	10
New Customer Meters	5	5	5	5	5
Replacement Customer Meters	2	2	2	2	2
	32	**31**	**23**	**23**	**23**
Category B					
Transmission	300	2,000	100	-	-
Distribution	68	95	35	160	35
	368	**2,095**	**135**	**160**	**35**
Category C					
IT	-	-	-	-	-
Non-IT	494	71	174	42	116
	494	**71**	**174**	**42**	**116**
Contributions in Aid of Construction					
	-	**-**	**-**	**-**	**-**
Total Regular Capital	**894**	**2,197**	**332**	**225**	**174**

figures exclude AFUDC and Capitalized Overhead

2 TGI FT NELSON 5 YEAR MAJOR CAPITAL PLAN

TGI Ft Nelson has one major capital project included in Regular Capital that is greater than $1 million for the period 2010-2014, the Muskwa River Pipeline Crossing.

2.1 Muskwa River Pipeline Crossing

In 2008, a scheduled survey of the existing 6" underwater Transmission pipeline crossing of the Muskwa River serving Fort Nelson was completed. The survey noted that the pipeline, as a result of river scour and bank erosion, was now exposed and subject to potential damage from river action.

To ensure continued integrity of the pipeline, TGI Fort Nelson completed an engineering assessment to determine appropriate and cost-effective repair options. The engineering assessment provided an opinion indicating that a pipeline replacement using horizontal directional drilling (HDD) methodology was the most cost-effective strategy.

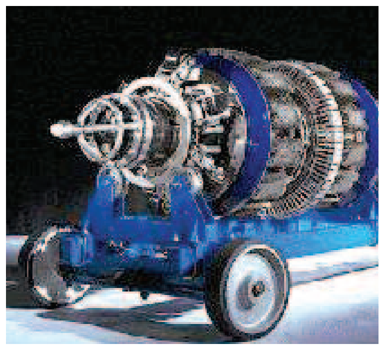
TGI Fort Nelson is completing a geotechnical profile of the proposed HDD pipeline crossing by the beginning of Q4 2010. If the results of this profile indicate that sub-surface conditions influencing HDD installations appear favourable and HDD installation risks are acceptable, TGI anticipates that it will proceed with this project sometime in late 2010 targeting an expected completion date of the project in 2011. Project costs for this option are currently estimated to be $1.64 million (excluding AFUDC).

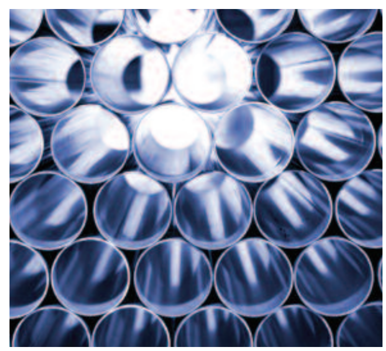
If the feasibility study indicates that an HDD installation is not favourable and/or HDD installation risks are not acceptable then TGI will consider the engineering assessment recommendation of relocating the pipeline onto the adjacent highway bridge and installing an additional pressure regulation station. The project cost for this option is currently estimated at $2.21 million (excluding AFUDC).

Appendix E

CGA GUIDING DOCUMENT ON ASSET MANAGEMENT

CANADIAN GAS ASSOCIATION
ASSOCIATION CANADIENNE DU GAZ





Canadian Gas Association

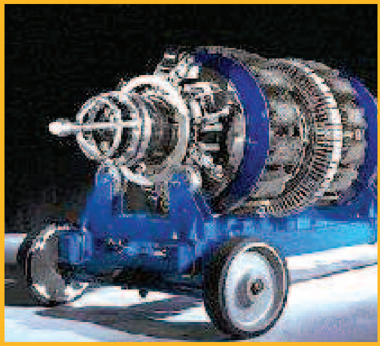
Asset Management Taskforce

Guiding Document on Asset Management

Published November 2009







Acknowledgements

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- CGA Standing Committee on Operations (SCO)
- The SCO Lead, Dwain Bell

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- Baltimore Gas & Electric Company
- BC Hydro
- Gaz de France (GDF Suez)
- Hydro Québec
- National Grid
- NICOR
- Pacific Gas and Electric Company
- PSE&G
- UMS Group, Inc.

CANADIAN GAS ASSOCIATION
ASSOCIATION CANADIENNE DU GAZ

Table of Contents

1.0 Introduction to Asset Management

The Canadian Gas Delivery business, which includes distribution and transmission companies, is an asset intensive industry. It requires substantial capital investments resulting in the creation of significant physical assets with long life cycles. It would be fair to say that Canadian Gas Delivery companies, some of which have been in existence for over 150 years, have been engaged in the practice of asset management for a long time. Therefore, it is important to clarify at the outset that the use of the term "asset management" in this guiding document refers to a comprehensive and strategic application of a set of concepts, techniques, and tools that, when adopted and used effectively, can enhance a company's current management of its assets.

Asset intensive industries such as aerospace, defense, oil and gas refineries, roads, bridges, railway works, and other utilities have been developing this asset management discipline since the late 1970s. In particular, Australia, New Zealand, and the UK have been leaders in the advancement and implementation of asset management, treating it as a holistic approach that considers the whole business and the whole asset over the long term. In more recent years, asset management has gained increasing attention among North American transportation/municipal infrastructure managers and electric and gas utilities.

1.1 Background

In early 2007, the Standing Committee on Operations (SCO) of the Canadian Gas Association (CGA) formed the Asset Management Task Force with a three year mandate to study and make recommendations with respect to the application of asset management best practices to the Canadian Gas Delivery industry.

The rationale for taking on this work was based on the current environment being one of changing regulations, increased scrutiny on costs, heightened awareness of the legal ramifications of not meeting stakeholder expectations, and the need to ensure that member companies focus their attention on how they maintain their assets. An effective gas delivery business relies on a broad variety of assets to achieve corporate strategic objectives. Optimal management of those assets is dependent on an optimized balance between asset performance, business risk, and expenditures.

Given this environment, the industry needs to collaborate on shaping asset management in order to meet the needs for public safety, reducing costs, developing process improvements through best practices, and reducing regulatory risks.

This guiding document is the culmination of the Asset Management Task Force's efforts to fulfill the SCO's mandate. Its objectives are to present a shared understanding of asset management and its relevance to the Canadian Gas Delivery industry and to provide practical recommendations for implementing asset management within member companies.

Applicable standards and local regulation may mandate requirements in excess of this document.

1.2 Definition of Asset Management

The task force gained a broad understanding of asset management from a number of reference sources, including PAS 55, a "Publicly Available Specification" published by the British Standards Institution (BSI). This specification was developed by a committee of the Institute of Asset Management (IAM) with consultation from various industries, government departments, and regulators. It outlines a management system for the optimized management of physical infrastructure assets.

Based on these reference sources, the task force has developed the following common definition of asset management as it pertains to the Canadian Gas Delivery industry:

> **"Asset management is a strategic management system used to optimally manage assets over their life cycle by balancing performance, risk, and expenditures to achieve corporate strategic objectives."**

The following high level concepts are intended to further clarify this definition:

Strategic management system

- Is a set of interrelated processes and controls designed to produce a significant result
- Includes the concepts of policy, planning, implementation, monitoring, evaluation, review, and continuous improvement with the focus on balancing performance, risk, and expenditures

Optimally manage assets

- Refers to critical capital assets that have a direct and significant impact on achieving corporate objectives
- Includes fixed, physical, and capital assets (e.g., pipeline system, buildings, and fleet)
- Includes planning, design, procurement, construction, operating and maintaining and decommissioning

Performance

- Includes developing an understanding of assets in terms of condition and performance

Risk

- Includes a consistent approach to risk identification and evaluation to support decision making
- Includes understanding risk tolerance

Expenditures

- Includes the concept of maximizing life cycle value
- Includes O&M and capital expenditures

Corporate strategic objectives

- Includes the concept of aligning asset-related decisions with corporate strategic objectives

1.3 Objective of an Asset Management System

The primary objective of an asset management system is to maximize the lifetime value of a corporation's assets in a way that is consistent with its strategic objectives.

To achieve this, asset management:

- Links the asset-related cost, risk, and performance decisions to the corporation's strategic objectives
- Provides a platform to more effectively utilize information to achieve the most value from assets while operating in a safe, sustainable manner
- Ties risk-based decision making to financial and other performance objectives

Further, asset management has the potential to integrate a company's existing management systems, such as Integrity, Measurement Accreditation, Environmental Health and Safety, Quality, and Safety & Loss.

The Canadian Gas Association should view asset management as a strategic response to the challenges that the industry is facing. These challenges include:

- Increased scrutiny on financial results due to strategic business drivers and the move from cost-of-service regulation to incentive regulation in some jurisdictions
- Expectations on risk-based decision making
- Increased expectations on the implementation of management systems in our organizations
- A continuing focus on operational excellence strategies
- A need to reduce costs without impacting safety and reliability
- Gas supply challenges driving a different look at expenditures (e.g., challenges with mitigating volatility in commodity pricing and the need to look at non-traditional sources like LNG)
- Declining residential use (normalized annual consumption) impacting revenues
- Addressing justification for replacement of aging infrastructure
- The ability to demonstrate that sustainability and environmental concerns are actively considered as part of asset utilization and selection
- Achieving enhanced customer satisfaction from improved performance and control of product or service delivery to the required standards
- Pending demographic issues

1.4 Scope of the System

Asset management principles could be applied at the enterprise level. However, our research to date indicates that most completed work in this area has focused on the practical application of asset management to physical assets only, as opposed to human, financial, information, or intangible assets. In the case of the Canadian Gas Delivery industry, the focus would likely initially be on core physical assets. Further application of asset management principles could then be extended to buildings and fleet.

With respect to these physical assets, asset management deals with the entire life cycle including planning, design, procurement, construction, operating and maintaining, and decommissioning.

Asset management should be viewed as a complete management system encompassing the entire "Plan-Do-Check-Act" cycle characteristic of all management systems. This guiding document does not set out to provide a detailed description of every element of a management system as it pertains to asset management. Section 2 of the guiding document will outline in some detail the "distinguishing elements" of an asset management system. Section 3 will provide a brief outline of the other "supporting elements" that are common to all management systems.

1.5 Potential Benefits

The Task Force has identified the following potential benefits of asset management that are specific to the Canadian Gas Delivery industry:

Improved Safety and Reliability

- Having the ability to understand and optimize the health of assets and asset systems
- Minimizing the impact of aging infrastructure
- Proactively provide insight into cost/risk decisions

Improved Financial Performance

- Investment optimization
- Reduced O&M costs
- Reduced annualized cost of ownership

Improved Regulatory Relationship

- Ability to prioritize spending with consistent, repeatable, and defensible decisions
- Creating industry alignment

Improved Decision Making

- Linking the corporate values and strategic plan to the physical asset decision-making process

Ability to capture tacit knowledge from aging workforce

- Asset Health Review provides a framework for gathering tacit knowledge from field workers and Subject Matter Experts (SMEs).

1.6 Stakeholder Considerations

To be successful, any enterprise must effectively balance the short-term and long-term, and often conflicting interests of multiple stakeholders. For example, customers and regulators expect gas delivery companies to meet or exceed safety, reliability, customer service, and cost expectations. On the other hand, shareholders expect companies to generate earnings, maximize the value of assets, and ensure the long-term viability and growth of the business. Asset management provides capabilities that help to achieve the required balance by linking asset-related decisions to corporate strategic objectives.

The asset management system can also provide a useful framework for more effective communication with stakeholders. As regulators become more familiar with asset management concepts and principles, it is anticipated that they may expect companies to submit asset health assessments and asset plans as part of the explanation and justification for proposed investments and operational expenditures. Considering the significant challenge that the industry faces with aging infrastructure, asset management can help companies present their investment needs to the regulator in a clear and defensible way.

2.0 Asset Management System Distinguishing Elements

Although asset management, as a management system, shares the same “Plan-Do-Check-Act” structure of most management systems, it includes a number of key elements that distinguish it from other management systems that member companies may currently be using. This section of the guiding document presents relatively detailed descriptions of these distinguishing elements. Member companies may choose to adopt and utilize these elements to varying degrees. However, these elements are interrelated and build upon each other; therefore, the full benefit of asset management may not be realized with only partial implementation.

2.1 Asset Health Review

Purpose:

To establish a baseline and identify trends indicating specific issues affecting the health of the assets in order to help identify and prioritize activities that need to be performed on the assets.

Deliverables:

Production of a recurring report with a consolidated view of the health of the assets, and identifying issues that require action or further study.

The cornerstone of the asset management system is the Asset Health Review. Its purpose is to establish a baseline and to identify trends in the performance and condition of the assets. It may involve gathering both quantitative and qualitative information. To facilitate identification of trends in asset health, reviews should recur at an appropriate frequency.

Knowledge of asset health helps an organization understand the likelihood of asset failure, or which assets may require continued or changing levels of attention to ensure that they perform their intended function over their intended life cycle. Responses may include new or revised maintenance practices, replacement, or “do nothing” decisions. Measures of asset health may help an organization prioritize its responses, possibly on the basis of failure likelihood or the rate of change in asset health or performance over time. This information is a required input into an Asset Management Ranking Mechanism or into selected Maintenance Optimization techniques such as Reliability Centered Maintenance (RCM). Within this document, discussion on these elements of an asset management system describes how the consequences of failure may be brought into the equation to formulate effective asset management strategies.

The Asset Health Review contains the following elements:

- A decision regarding which assets to include
- A categorization of the assets into asset groups and, potentially, sub-groups
- An inventory of those assets by group and sub-group
- Metrics used to measure condition and performance of the assets
- Maintenance history
- Projected life
- An assessment of the asset’s current condition and performance

All sources of information should be mined including, design and procurement data, construction files, maintenance files, operating files, and tacit knowledge from construction, operations, and maintenance personnel. New processes may need to be developed to gather the information.

The assets need to be categorized. An example of a categorization of gas delivery plant assets into groups and sub-groups is shown below.

Asset Categorization

MAINS	**Polyethylene**	≤ 700 kPa	≤ NPS 6
			NPS 6 - 16
		700 < x ≤ 1900 kPa	≤ NPS 6
			NPS 6 - 16
	Coated Steel	≤ 700 kPa	≤ NPS 6
			NPS 6 - 16
			> NPS 16
		700 < x ≤ 1900 kPa	≤ NPS 6
			NPS 6 - 16
			> NPS 16
		> 1900 kPa	≤ NPS 6
			NPS 6 - 16
			> NPS 16
	Other Materials	Aluminum • Bare Steel • Cast Iron • Composite • PVC • Other	
SERVICES	**Polyethylene**	≤ 700 kPa	≤ NPS 6
			NPS 6 - 10
		700 < x ≤ 1900 kPa	≤ NPS 6
			NPS 6 - 10
	Coated Steel	≤ 700 kPa	≤ NPS 6
			NPS 6 - 16
		700 < x ≤ 1900 kPa	≤ NPS 6
			NPS 6 - 16
		> 1900 kPa	≤ NPS 6
			NPS 6 - 16
	Other Materials	Aluminum • Bare Steel • Cast Iron • Composite • PVC • Other	
STATIONS	**District Regulator**	≤ 6000 m3/hr	Farm Tap
			Other
		> 6000 m3/hr	
	Customer Stations	Diaphragm Meters 200 series and smaller	Inside Customer Premises
			Outside Customer Premises
		Diaphragm Meters larger than 200 series	Inside Customer Premises
			Outside Customer Premises
		Rotary Meters	Inside Customer Premises
			Outside Customer Premises
		Turbine Meters	Inside Customer Premises
			Outside Customer Premises
		Other Meters	Inside Customer Premises
			Outside Customer Premises

Once the groupings and sub-groupings of the assets have been decided, an inventory of the assets by these groupings and sub-groupings needs to be established. Other parameters that could be considered in grouping and sub-grouping assets include material, wall thickness, pressure rating, meter capacity, regulator capacity, and age.

Metrics allow the various assets to be compared against industry and internal benchmarks and key performance indicators. They also allow a comparison between asset groups. The metrics could include such data as leaks/km, damages/km, meter seal extensions, age, mileage, and network usage. Existing industry metrics should be considered as this provides the opportunity for collaboration between departments and possibly other companies in the gas delivery industry. Examples of possible metrics that could be used to define the performance and condition of distribution assets are shown below.

Asset Health Indices

PERFORMANCE HEALTH INDICES
Cost Operating and Maintenance
Reactive O&M $ per km Main
Reactive O&M $ per Service Line
Reactive O&M $ per M&R Facility
Events • 3rd Party Damages
Damages per km Main
Damages per Service Line
Damages per M&R Facility
Events • Corrosion
Corrosion Shorts per km per year
% Annual Downtime per km (est.)
Corrosion Repairs per km per year
Events • Leaks
Leaks per km of Main per year
Leaks per Service Line per year
Leaks per M&R Facility per year

CONDITION HEALTH INDICES
Cost Operating and Maintenance
Preventative O&M $ per km Main
Preventative O&M $ per Service Line
Preventative O&M $ per M&R Facility
Condition • Residual Life
Mains
Service Lines
M&R Facilities
Events • Corrosion
Corrosion Health Rating per km
Events • Leaks
Leaks per km over multiple years
Leaks per Service over multiple years
Leaks per M&R over a specified period
Fittings of Interest
Mains
Service Lines
M&R Facilities

These types of measurements provide information required in making assessments and decisions about the assets, such as: fitness for purpose, remaining life, and prioritizing maintenance and replacement expenditures. They also provide the foundation for capital and maintenance optimization.

2.2 Asset Management Ranking Mechanism

Purpose:

To establish a methodology and supporting tools to help assess and compare capital investment opportunities based on financial, risk, and strategic considerations in order to rank these opportunities according to their total business value.

Deliverables:

Ranking of a project relative to other investment opportunities.

Another important component of the asset management system is the development of a mechanism to assess and rank investment opportunities. This can be a complex task as it involves objectively prioritizing the organization's business strategy, getting consensus between stakeholders, and assessing and prioritizing competing spend requirements. In essence, this attempts to compare various investment opportunities on an "apples-to-apples" basis.

The range of techniques used to rank investment opportunities can vary from qualitative to quantitative and depends largely on the data available, ease of use, and level of understanding of employees. Whether the system is qualitative, quantitative, or somewhere in between, the important aspect is that it be disciplined and structured so as to ensure consistency.

A logical starting point is to develop a scoring criterion to evaluate and prioritize competing investment proposals. Again, this is no small task when considering how many varied projects, programs, and applications should be assessed in order to optimally allocate resources within an organization. Asset management best practices strive to objectively and systematically assess projects, programs, and applications by taking into account strategic value, financial value, and risk. Essentially, each project is assigned a value in these key areas and is ranked according to the overall score.

Strategic Value

Asset management attempts to link asset-related decisions to the strategic objectives of the company. Therefore, one of its fundamental primary tasks is to define and prioritize the organization's business strategy. Once again, this can be challenging because executives from different functional areas may have distinct perspectives on which drivers are the most important to the business. The Marketing Vice President may consider "increase market share" to be the most important business driver, while the Operations Vice President may consider "reliable and safe delivery of natural gas" to be the most important. They can also often view assets as individual, stand-alone projects rather than pieces of a greater whole. It is especially important to achieve understanding and consensus because the entire organization is competing for finite resources. Fundamentally, all assets owned by the organization should contribute optimally to the business strategy.

Prioritizing the organization's business strategy can be achieved simplistically by ranking the business strategies 1-10 or using more advanced techniques, such as a pair-wise comparison matrix that assesses each business driver against one another. Regardless of the methodology used, the important aspect is achieving consensus and understanding.

Each project, program, or application will then need to have a strategic value assigned to it so as to clearly indicate how it contributes to the overall business strategy.

Financial Value

Project financials, which are typically part of an organization's business case requirements, summarize the project in financial terms. Every item associated with the project needs to be quantified as best as it can be known at the time of the business case development. Again, this is nothing new to member companies, but with asset management, the financials need to include full life cycle costs. It is therefore important to quantify investment dollars as well as ongoing operating costs such as maintenance, depreciation, etc., and the potential revenue generation for each project.

Finally, the information is presented in the form of financial metrics. There are many financial metrics that can be used for comparison purposes, each with advantages and disadvantages to their use. Each organization must determine which financial metrics will be used in their asset management ranking mechanism in order to provide a financial value.

Risk Value

Another aspect to be considered is the risk score for each project. In our industry, organizations mitigate risks through established policies, practices, procedures, and solid engineering principles. However, without assessing each project individually the total risk profile may not be well understood. It should be considered that even deferred projects can affect the overall risk profile that the company may be exposed to because these deferred projects may leave the company with a retained risk.

Risk is defined as a function of likelihood (i.e., how likely is it for the asset to fail) and consequence (i.e., how severe are the impacts of asset failure). There are several risk analysis tools available to determine a risk score; they range from relative risk ranking to comparison of quantitative risk estimates to established risk tolerability criteria. These can include, but are not limited to, Matrix risk ranking, Nomogram ranking, Level of Protection Analysis (LOPA), Event Tree and Fault Tree Analysis (FTA), Failure Modes and Effect Analysis (FMEA), and Quantitative Risk Assessment (QRA). For most situations a full quantitative risk assessment may not be feasible; however, a simplified risk matrix approach will normally be sufficient for relative ranking. The point is that each organization needs to develop a tool that works for it and then apply the tool consistently to all projects.

Qualitative measures of likelihood may include considering condition of the asset, effectiveness of O&M protocols, capacity and utilization, annual maintenance. A sample rating system is shown below.

Level	Descriptor	Example detail description
L1	Rare	May occur only in exceptional circumstances
L2	Unlikely	Could occur at some time
L3	Possible	Might occur at some time
L4	Likely	Will probably occur in most circumstances
L5	Almost certain	Is expected to occur in most circumstances

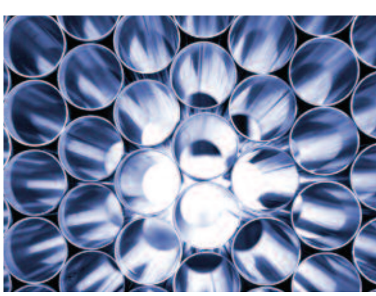
Qualitative measures of consequence/impact may consider loss of service, effect on the environment, health and safety implications, community disruption, damage to property, loss of revenue, regulatory compliance and public image. A sample rating system is shown below.

Level	Descriptor	Example detail description
C1	Insignificant	No injuries; low financial loss
C2	Minor	First aid treatment; on-site release immediately contained; medium financial loss
C3	Moderate	Medical treatment required; on-site release contained with outside assistance; high financial loss
C4	Major	Extensive injuries; loss of production capability; off-site release with no detrimental effects; major financial loss
C5	Catastrophic	Death; toxic release off-site with detrimental effect; huge financial loss

By plotting its likelihood and consequence on an established matrix, each project can then be assigned a numeric risk value to be used in the overall ranking score. A sample matrix is shown below.

LIKELIHOOD RANGES						
	L5	5	10	15	20	25
	L4	4	8	12	16	20
	L3	3	6	9	12	15
	L2	2	4	6	8	10
	L1	1	2	3	4	5
		C1	C2	C3	C4	C5
		CONSEQUENCE SEVERITY				

The higher the ranking the more critical the project and therefore the more worthy it is to receive funding. As with most tools, one size does not always fit all scenarios so it is also important to allow a management over-ride to allow for funding of projects that are considered “unrankable” or “must do” according to the risk matrix.



2.3 Capital Optimization

Purpose:

To provide a methodology and supporting tools to help select a set of capital investment opportunities which maximizes contribution to corporate strategic objectives while balancing performance, risk, and expenditures.

Deliverables:

An optimal portfolio of capital investments.

Limited funding availability and increased fiscal accountability may drive the need for Canadian Gas Delivery companies to adopt a new approach to budget decision making. An objective capital optimization methodology links decision making and action with asset information.

A key benefit of asset management comes from the ability to optimize the expenditure of capital by creating the right balance between cost, performance, and risk that is consistent with a company's corporate strategic objectives and obligations.

Required capital expenditures

Some capital expenditures must be made. They are non-discretionary and receive top priority for capital funds. For various reasons, certain projects or expenditure requirements arise and are not within the purview of the company to deny or defer. These expenditures could include those required for regulatory compliance, business continuity, franchise obligations, or non-controllable third party activities such as road widening.

Where a project is approved, initiated, and funded as a multi-year expenditure, the expenditures required in subsequent years may also be considered to be in this non-discretionary category. Based on the nature of the expenditure or project, cancelling the expenditure partway through may be imprudent or have significant financial implications. Once started, expenditures in this realm should continue until completion.

Rankable capital expenditures

Given a suite of capital investment opportunities, decisions must be made on what will and what will not receive capital funding. The asset management ranking mechanism discussed earlier lays out objective criteria and techniques to rank investment opportunities based on parameters such as strategic value, financial value, and risk value. The ranking mechanism yields a method to develop a portfolio of capital investment opportunities based on the prioritization criteria used by the company.

With a proper, objective ranking mechanism, capital can be focused where it is best aligned with corporate objectives and can be applied to a wide range of investment opportunities. In addition to investments in plant, the ranking mechanism can assess and rank diverse capital requirements such as fleet, buildings, tools, and information technology.

Portfolio Optimization and Management

With the ability to rank projects, all capital needs can be brought together into a portfolio of projects to facilitate capital optimization and management. A portfolio can be managed by applying a limited capital pool to the highest-ranking projects, (i.e., those that deliver the greatest value based on the ranking mechanism). Funding would be applied to the highest-ranked remaining opportunities until the capital pool is exhausted.

Alternatively, a company could determine that it will support expenditures that make a certain hurdle based on the ranking criteria. The portfolio would rank opportunities, highlighting those that meet or exceed the cut-off hurdle applied. Those opportunities falling below the hurdle would not receive capital funding.

This will permit capital expenditure deferral for investment opportunities where the current determination of value for that investment falls below the value of other opportunities. The investment opportunity will be kept for subsequent re-ranking and should the situation change and the criteria applied yield a higher ranking at a later date, it will then receive capital funding.

Further, the portfolio can be divided into sub-portfolios, such as customer-related projects, system integrity projects and information technology projects, to allow a two-stage optimization process.

Each sub-portfolio could be optimized to meet specific criteria. For example, a company objective of adding 25,000 customers this year will require that capital be allocated in the customer-related sub-portfolio. Optimizing this sub-portfolio could involve considering factors such as the expected revenue and return on equity that these new customers will generate versus any capital constraints. Attempts to optimize this sub-portfolio could also focus on ensuring that unit cost per customer addition is optimized.

Other sub-portfolios could be similarly optimized. Then all sub-portfolios would be brought together and the portfolio as a whole could go through a separate stage of optimization. This portfolio optimization would look at various scenarios of return versus invested capital, and could involve trade-offs between sub-portfolios based on overall project rankings and overall capital constraints.

The portfolio is also used to maintain the ranking of projects should additional capital become available. The additional capital can then be applied next to the highest-value opportunity of those opportunities remaining.

Portfolio management provides a tool to apply objective criteria to the choice of which of many investment opportunities receive the often limited capital funding available. It reduces judgment bias traditionally associated with less rigorous capital expenditure planning.

Example of a Capital Investment Portfolio

	Project	Investment Cost ($m)	Total Business Value	Profitability Index
	C	50	160	3.2
	B	10	27	2.7
	A	25	52.5	2.1
	D	40	76	1.9
	I	80	136	1.7
	L	15	24	1.6
	H	30	42	1.4
$250M Threshold	Sub-Total	250		
	E	10	13	1.3
	G	25	30	1.2
	K	15	16.5	1.1
$300M Threshold	Sub-Total	300		
	M	60	66	1.1
	J	15	13.5	0.9
	F	25	17.5	0.7
$400M Threshold	Sub-Total	400		

2.4 Long-term Capital Planning

Purpose:

To assess the long-term capital needs of the assets to support system growth, asset replacement, and operational performance.

Deliverables:

A capital plan with a sufficiently long time horizon to prepare for orderly system growth and asset replacement.

Asset management values a multi-year perspective. Capital planning needs to look at not only initial capital costs, but also, through life cycle costing, future costs as well. Costs are minimized starting with the initial investment, continuing through operations and maintenance, and ending with disposal. The connections between the choice of assets and their lifecycle costs are critical. These connections require that multi-year asset plans be integrated with multi-year financial plans.

Delivery systems require capital planning for system growth, to expand the delivery system to new areas, and to connect new customers. Capital is also required for asset replacement. To maintain safe, reliable service, assets need to be replaced as they deteriorate, become obsolete, or when risk of failure becomes intolerable.

System growth

Multi-year capital plans are required to manage system growth. While customer energy choices, changes in the economy, and conservation efforts may reduce the load in certain areas, new customer growth will add load, requiring capital investment for customer additions and system capacity. Economic drivers can drive load changes in certain economic sectors or customer classes. This can result in load patterns that evolve over time requiring plant additions to meet the growing or shifting load patterns. As these developments typically follow multi-year trends, they require a multi-year focus and planning to provide the capital at the required level to meet these opportunities and obligations. Part of capital optimization is determining an appropriate planning horizon for system capacity planning and design.

Asset replacement

A multi-year plan is essential for asset replacement plans. As plant reaches the end of its serviceable life, or as materials and technologies are developed, replacement is required for continued delivery system operation or performance. Asset replacement is not a new concept for many utilities. Many years ago, several utilities replaced original wooden pipes with pipes made of cast iron. This cast iron is now being replaced with steel or plastic pipes. Some of the early plastic pipes are approaching the end of their useful life and similarly will need replacement. Other components of the delivery system, such as regulators, meters, pressure regulation stations, and compressor stations, will require replacement at some point due to equipment obsolescence, end of useful life, or changing system capacity requirements. With the vast magnitude of asset replacement needed for system renewal, a multi-year focus is vital.

Operational performance

Maintaining or improving system reliability also requires a multi-year focus. Capital expenditure planning is required for system reliability improvements to mitigate customer impacts related to potential failures of supply or flow continuity in a delivery system. This could include system reinforcements such as looping or back-feeding. Long-term planning is appropriate to address pipeline system management issues. Technology is constantly improving and operational data requirements are increasing. A multi-year approach may be required for projects that implement the acquisition of data such as pressure, flow, and operational status at facilities such as pressure regulation stations, pipelines, or individual customer delivery points.

In summary, long-term capital planning ensures that the needs of assets can be accommodated in an orderly manner, without incurring rate shocks or other negative consequences. Long-term capital requirements need to be understood so that efforts can be made to smooth out capital requirements and to ensure that regulators and other stakeholders are informed about long-term capital needs.

Example of Changing Capital Expenditures in a Capital Forecast

2.5 Life Cycle Costing

Purpose:

To establish a methodology and supporting tools to help assess the total life cycle costs of an asset.

Deliverables:

A Life Cycle Costing Model to help determine the economic life of an asset and support repair/replace and other asset-related decisions.

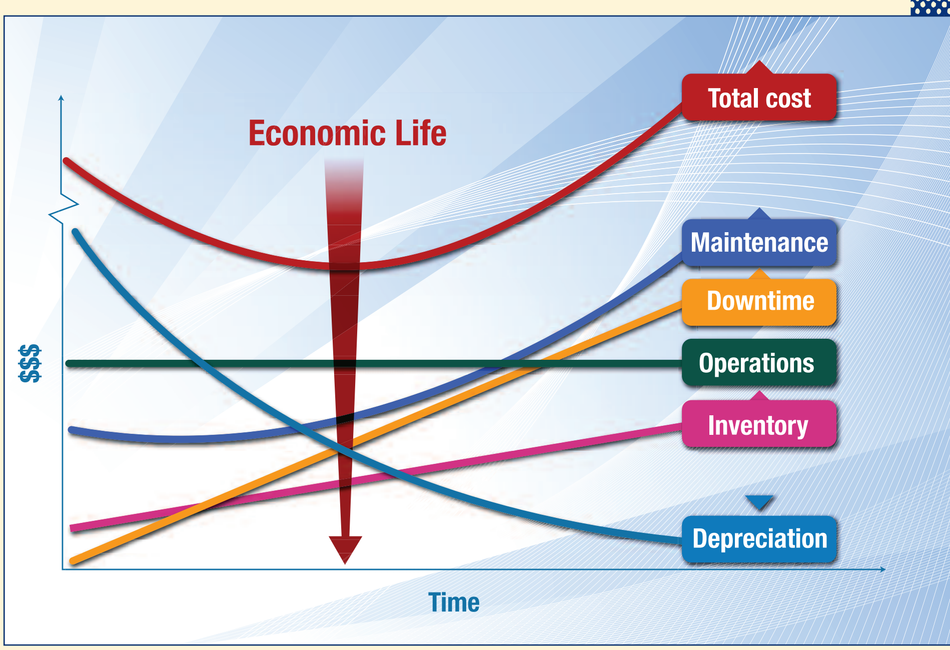
Life Cycle Costing looks at the total costs that may be encountered throughout an asset's lifetime, including planning, design, procurement, construction, operating and maintaining and decommissioning.

Understanding life cycle costs provides a means to help assess a variety of asset management decisions, such as:

- Affordability/financial impact of current and proposed practices
- Source selection (supplier studies)
- Possible need for design trade-offs due to sustainment cost impacts
- Appropriate repair levels and changes over time
- Repair versus replace strategies
- Determining the economic life of an asset

A generic "Economic Life Model" is illustrated below.

Economic Life Model



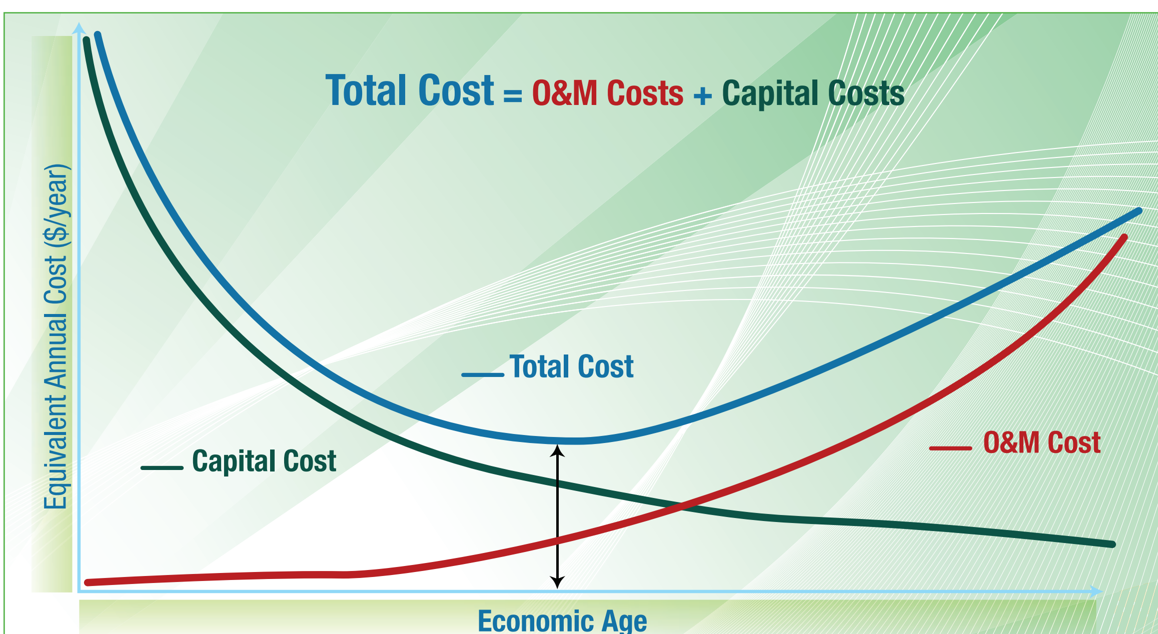
Inputs to a life cycle cost analysis would typically include the following:

- Expected rate of return
- Depreciation rate
- Investment tax credit, capital cost allowance, CCA depreciation type, federal and provincial tax rates
- Inflation rates
- Unit purchase year and price
- Unit yearly total operating and maintenance costs
- Unit yearly salvage returns
- Replacement costs

As a practical example of how Life Cycle Costing can be applied to Canadian Gas Delivery assets, consider the following Life Cycle Costing Model for cathodically protected steel mains.

The model involves deriving a Total Cost curve by summing the Capital Cost curve and the O&M Cost curve for this class of assets. The Capital Cost curve would be based on factors such as initial capital costs, depreciation, and eventual abandonment costs. The O&M Cost curve would be based on all of the potential maintenance costs of sustaining the asset, such as inspection costs, cathodic protection costs, and repair costs. One of the major challenges in developing the O&M Cost curve is predicting the repair costs due to leaks over time. However, there are well-established maintenance engineering models, such as the Proportional Hazards Model (a statistical procedure for estimating the risk of equipment failure when it is subject to condition monitoring), which can be applied to this problem.

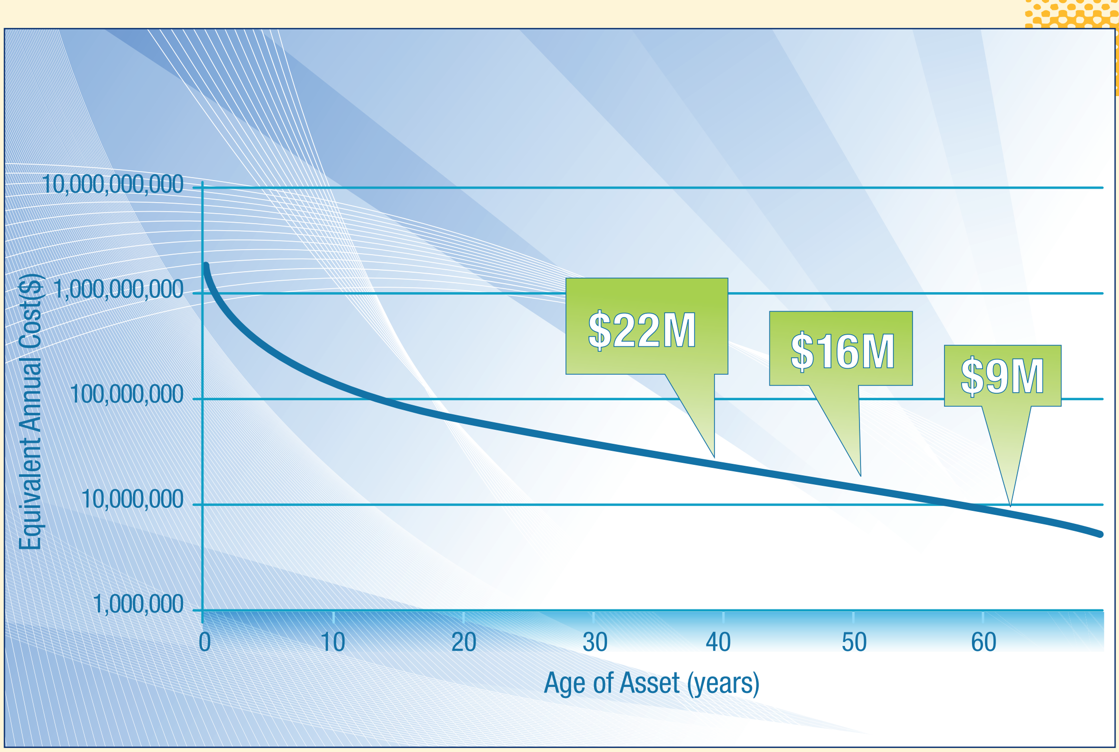
Life Cycle Costing Model



The first benefit that can be derived from the Life Cycle Costing Model is the predicted economic life of the asset. Having a better understanding of the economic life of assets is clearly useful for long-term capital planning. The Life Cycle Costing Model can also be used to provide a more rigorous basis for repair/replace decision making.

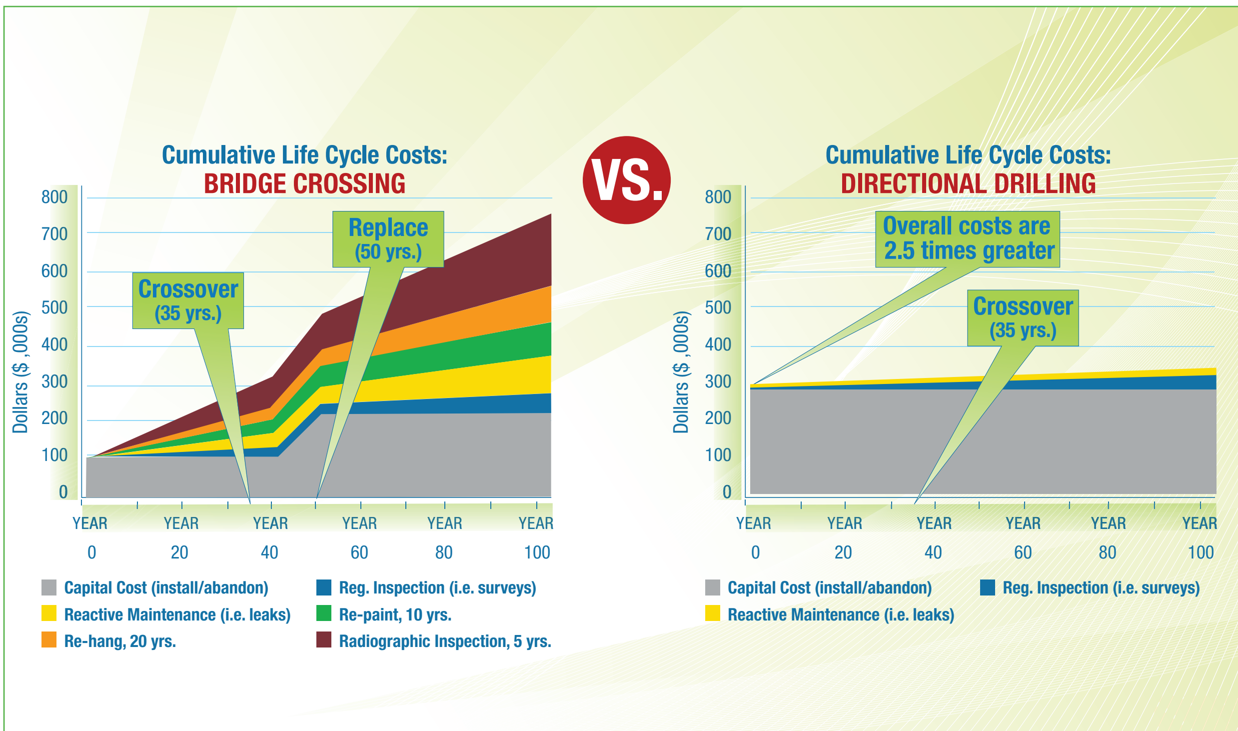
Having a better understanding of the life cycle costs of assets also highlights the significant benefit of taking appropriate measures to extend the economic life of the assets. The graph below illustrates the savings opportunity, in terms of Equivalent Annual Cost of ownership, if the life of the assets can be extended.

Value of Extending Asset Life



Another potential benefit of having a better understanding of life cycle costs is to support decision making where alternative solutions exist to a given problem. For example, when faced with spanning a river with a pipeline, alternative solutions may be available, such as a bridge crossing versus installing the pipeline under the river using directional drilling. The initial capital costs of the directional drilling option are considerably higher than the bridge crossing option. As a result, the common industry practice is to choose the bridge crossing option. However, the bridge crossing option inherently requires more maintenance over time. A better understanding of the life cycle costs of these two options might reveal that the directional drilling option is the better long-term financial choice.

Optimizing the Cost of Ownership



2.6 Maintenance Optimization

Purpose:

To establish an optimal maintenance portfolio by balancing performance, risk, and expenditures.

Deliverables:

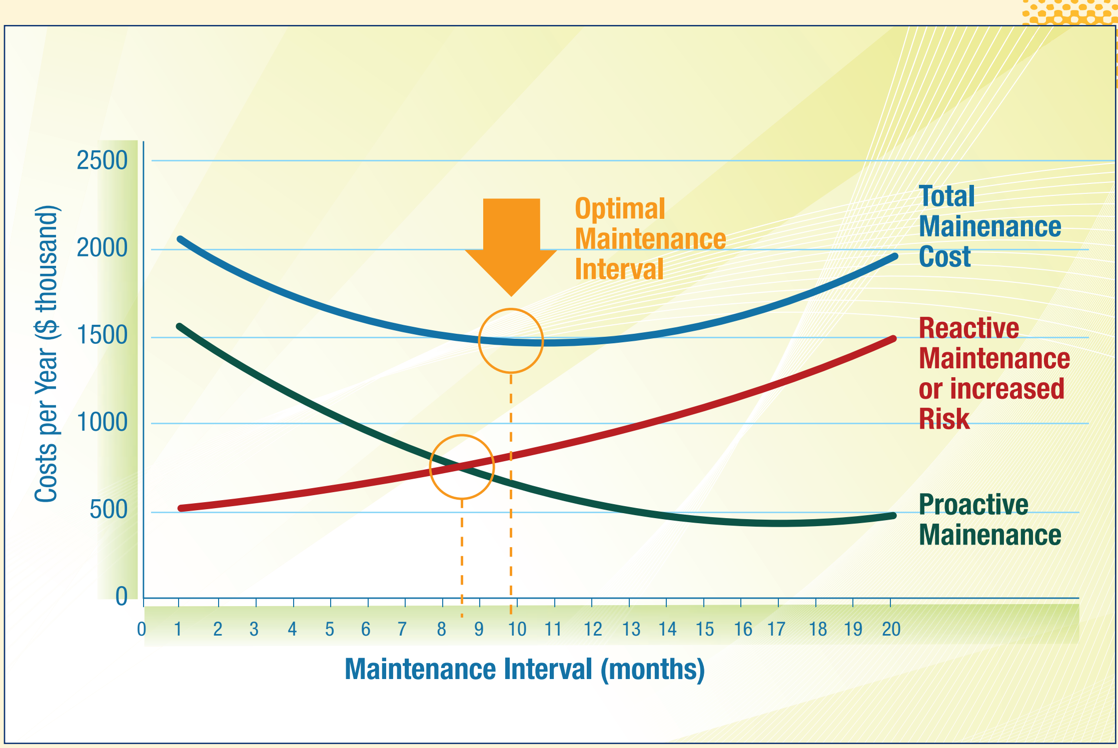
Optimized maintenance tactics and maintenance intervals.

Maintenance Optimization refers to the allocation of operating and maintenance (O&M) funds in accordance with corporate strategic objectives by balancing risk, cost, and performance. To achieve this, appropriate maintenance tactics and maintenance intervals must be identified.

Different maintenance tactics may apply depending on the nature of the assets, their intended function, their failure modes, and the consequences of failure. Examples of maintenance tactics include run-to-failure, condition-based maintenance, and time-based maintenance.

Optimizing maintenance intervals involves determining the interval that minimizes the sum of proactive and reactive maintenance activities.

Optimizing Maintenance Intervals



As a general statement of current industry standard practice for Canadian Gas Delivery companies, it can be said that maintenance activities and frequencies are generally derived from the following sources:

- Prescriptive frequencies in regulations or adopted standards
- Industry standard practices
- Manufacturer's recommendations
- Risk assessments, where data is available to support decisions and/or where it makes business sense to expend the effort on a risk assessment

As the field of asset management has expanded, more specific tools, methods, and concepts have been developed for the purposes of achieving specific outcomes, such as reliability centered maintenance (RCM).

RCM is an analytical process used to determine appropriate failure management strategies to ensure safe and cost-effective operation of a physical asset in a specific operating environment. Implementing a proactive maintenance program using RCM has been shown in many applications to greatly reduce the cost of ownership of an asset.

The RCM methodology develops the appropriate maintenance tactics through a thorough and rigorous decision process as shown below.

The RCM Process

Maintenance actions are performed to mitigate functional failures. A decision logic tree is used to select the appropriate maintenance tactics for the various functional failures.

The path to maintenance optimization can be through expansion of data-based and risk-based decision making. This requires collection of information from asset operation and maintenance work, analysis and measurement of asset and program performance, and continuous improvement through revised O&M plans and programs.

3.0 Asset Management System – Supporting Elements

Asset management has been consciously defined as a strategic management system, which implies a collection of distinct, ongoing, and interlinked elements that should be performed in order to fully achieve the benefits of asset management. These elements will most likely exist, in various stages of maturity, within an organization either as stand-alone programs or within the framework of other management systems. These elements should therefore be interlinked appropriately so as to address the asset management objectives and follow a "Plan-Do-Check-Act" approach that is consistent with many international management system standards.

3.1 Policy

The purpose of an asset management policy is to declare the organization's commitment to the development and implementation of an asset management system. It will provide the vision, high level guidelines, common principles, and goals that can be communicated to all stakeholders to ensure the asset management system's ongoing suitability, adequacy, and effectiveness. The policy should be approved and endorsed by top management.

3.2 Objectives, Targets, and Planning

The organization should define a process for developing and reviewing objectives and targets to ensure consistency with the asset management policy, vision, and goals. This will promote objectives and targets with proper documentation, communication, implementation, and periodic review. To achieve the targets adequate resources must be provided.

3.3 Document Management

Documentation of policies, practices, and procedures forms the basis for understanding the asset management system. It is foundational in assisting to describe and communicate the asset management system to others and as a basis for training, auditing, and objective setting. The extent of the required documentation depends upon the size of the organization, the complexity and interaction of the processes, and the competency of the organization's people.

The organization should define the requirements and processes for ensuring that the asset management system and all associated documents are controlled appropriately. This includes defining how documentation is prepared, reviewed, approved, distributed, revised, and archived in a controlled manner. It is also important to define who requires the use of this documentation and ensure that it is made available at all required locations.

3.4 Records Management

A record is a special type of document that provides evidence that an activity has taken place or an event has happened. Records also provide all relevant information about an asset, such as condition, manufacturing reports, quality reports, mill reports, pressure tests, design drawings, corrosion reports, and leak reports.

The organization should define the requirements for the maintenance of records from the time they are created until their eventual disposal. This is critical because of the primary concern with respect to evidence of activities, and the extensive data requirements needed for various asset management analyses. Records can be either physical, such as paper-based drawings, test charts, bill of materials, or digital, such as GIS, databases, and emails. Records management should include establishing protocols for the identification, storage, protection, retrieval, retention, and disposition of all records.

3.5 Legal and Other Requirements

Ensuring compliance with all legal and other requirements is paramount in a regulated industry.

The organization should define the process used to identify and provide access to legal and other requirements and ensure compliance. This should include the identification of requirements, including federal, provincial, and municipal regulations; operational permits and approvals; licences and authorizations. Once identified, these requirements must be reviewed periodically to ensure continued compliance.

3.6 Risk Management

The organization should establish a means to identify, assess, control, mitigate, and establish its tolerance of risks. Managing risks will help a company operate within the established levels of tolerance. Risk Management is a systematic approach to decision making that addresses uncertainty, increases transparency, and supports due diligence while considering all stakeholders’ interests. Examples of risk include financial performance, operational performance, market share, safety, image, environment, legal compliance, and regulatory compliance.

Understanding, assessing, and managing risks and aligning them to strategic values will help an organization optimize its decisions.

3.7 Training and Competency

Having competent personnel at all levels of the organization is critical to meet the goals of the asset management system. It is essential that the organization ensures the competency of personnel, including employees and agents of the company, with critical asset management tasks and processes. Competence should be based on appropriate education, training, skills, and experience. The determination of the necessary competence required, the assessment of competence, the action necessary to address competency gaps, and the evaluation of the effectiveness of actions to close competency gaps are all key components that must be addressed. Guidance for competency assessment can be found in the CGA Competency Assessment Plan (CAP) November, 2007.

The organization should ensure that training needs for all critical roles are identified and competency assessed for those performing these functions.

3.8 Performance Evaluation and Audit

The organization should determine the processes required to achieve the asset management goals and ensure that the necessary performance evaluation, including monitoring, measuring and analysis, is done. The intent is to identify trends and factors for continual improvement. In addition to performance evaluations, the organization should conduct internal audits at planned intervals to determine whether the management system conforms to plans and is being effectively implemented and maintained. Audit results should be documented and reviewed at the appropriate level of management to ensure follow-up and continual improvement.

3.9 Communication

Communication is key to the successful implementation and understanding of the asset management system. The organization should develop a communication plan that defines the key requirements, responsibilities, and methods for communicating information to internal and external stakeholders.

3.10 Management Review

Management review of the asset management system is the responsibility of top management and must identify opportunities to improve the system and its processes.

The organization should define the process by which top management will periodically review the management system to ensure its continuing suitability, adequacy, and effectiveness. The review should address the potential need for changes to policy and objectives based on results of audits, changing circumstances, and the commitment to continual improvement.

3.11 Management of Change

The organization should define the methods for managing the implementation of a change and accounting for how the decision to make the change was reached. This should include, at a minimum, a decision-making process, documentation, and an approval process. It must ensure that critical aspects are properly considered prior to implementing a change within the asset management system. Changes typically pertain to plant and facilities, procedures, materials, construction, operations, equipment, information technology, and organizational changes. Asset-related changes are a particular concern within asset management.

4.0 Implementation Considerations

In planning the implementation of an asset management system, there are a number of issues that need to be considered to help ensure success. This section highlights a number of these issues.

4.1 Management Commitment and Governance

Effective implementation of an asset management system requires an environment of organizational buy-in and culture change. This environment, at a minimum, requires the commitment of the company's top management. Without such commitment, it will be difficult to achieve employee buy-in and empowerment, leading ultimately to failure in the implementation of the organization's asset management objectives. Commitment to an organization's asset management objectives can be supported by its top management by:

- Appointing a member of the Executive to act as a Sponsor to the organization's asset management initiatives
- Ensuring the company's asset management policy is consistent with the organization's overall and long-term objectives
- Communicating to the organization the overall asset management objectives through a defined communication plan

In addition to having top management commitment, it is important to ensure decision-making accountabilities are clear. To accomplish this, roles, responsibilities and authorities need to be defined, documented, and communicated to individuals across the organization. This should include assigning responsibility for the various assets to member(s) of management. These assignments will include the necessary authority to ensure the strategic asset management objectives set for the various assets are achieved.

At the same time, corporate governance needs to be addressed by ensuring the consistency, viability, and continuity of the company's asset management plan as compared to its overall corporate goals and policies. This can be accomplished by a review of existing and proposed process and policy, then the establishment and maintenance of an organizational structure of roles, responsibilities and authorities.

4.2 Organizational Structure

For a Canadian Gas Delivery company to successfully implement an asset management system, consideration must be given to the company's organizational structure. While there is a certain freedom and flexibility as to the levels and/or elements of an asset management system that a company may choose to implement, certain organizational structures may help optimize the process.

It should be noted that organizational structure changes may not be required, provided the company's existing organizational structure aligns with the organization's asset management objectives. However, because an asset management system involves many functions within an organization, one of the most challenging aspects of implementing an effective system may be organizing the people involved. An effective organizational structure will help focus the functions, relationships, responsibilities, authorities, and communications of the staff within the company. While organizational change is not a prerequisite for implementing an asset management system, it is important that the company understands the implications, benefits, and challenges of how different organizational structures will relate to asset management. There are many different types of organizational structures, and for simplification only three types of organizational structures will be discussed. The three structures to be considered are: Functional, Divisional, and Asset Owner/Asset Manager/Service Provider.

Functional structures organize employees based upon the functions of specific tasks within the organization. Typically, functional organizational structures are utilized in small, geographically-centralized companies. The benefits of a functional structure when trying to implement an asset management system are:

- Centralizes decision making
- Avoids duplication of processes and activities
- Develops a strong core of technical knowledge

Some of the challenges that may be faced when implementing an asset management system in a functionally structured organization are:

- Groups tend to focus on individual tasks and not on overall goals
- Difficult to coordinate activities between various task groups
- May experience restrictions in decision making

Divisional structures can typically be divided into three classes: product, market, and geographic. Based on the nature of the Canadian Gas Delivery Industry, only geographic structures will be considered in this document. Geographic structures organize employees based upon their specific geographic location. Typically, geographic-divisional organizational structures are utilized in large, geographically dispersed companies. The benefits of a geographic-divisional structure when trying to implement an asset management system are:

- Decision making can be streamlined at the operational level
- Accountability is improved as each work group is directly responsible for their group's performance.
- Improves coordination of tasks between various asset classes/groups

Some of the challenges that may be faced when implementing an asset management system in a geographic-divisional structured organization are:

- Difficult to coordinate entire asset class decision making
- Difficult to evaluate risks between various asset classes
- Hard to allocate corporate staff support
- Culture change may be difficult to implement
- Loses some economies of scale
- Fosters rivalry among divisions

An Asset Owner/Asset Manager/Service Provider organizational structure leads to a company becoming more asset-centric. Under this model, a separation between asset-related decision making and work execution is made. This leads to a culture of asset-driven decision and investment activities. With this organizational structure, the complexity of managing assets is clarified by dividing responsibilities among the Asset Owner, Asset Manager, and Service Provider.

Under this structure, the Asset Owner is the group that sets an organization's business values, risk tolerance level, corporate strategy, corporate structure, and financial and operational performance targets. In this role, the Asset Owner would address the areas of:

- Governance
- Finance
- Regulatory Management
- Business Planning

Taking guidance from the Asset Owner, the Asset Manager is the group that formulates asset strategies and decisions along with optimizing asset value in line with Asset Owner objectives. In this role, the Asset Manager is accountable for:

- Clearly defining asset strategies
- Procurement
- Project management
- Economic decision making
- Ensuring asset performance and integrity
- Performance analysis
- Financial analysis
- Risk management
- Implementation strategies and policies

The relationship of the Asset Manager to the Service Provider is to provide technical support and convey decisions regarding the building, operation, maintenance, and replacement of the assets. The Service Provider is the group that accomplishes the front line execution of the Asset Manager's plan and day-to-day operation of the assets. In this role, the Service Provider group would:

- Manage the scheduling of resources
- Monitor asset performance
- Acquire resources
- Continually improve performance
- Provide continuous support to the operation and repair of the assets in the company's system
- Meet defined service levels
- Provide asset performance feedback and data

The benefits that may be experienced when establishing an asset management system in this type of organizational structure include:

- Specialization within groups leading to focus on specific capabilities and responsibilities
- Improved understanding of the impact of spending on asset condition by geographic area and asset type
- Increased capital efficiency
- Defensible investment decisions
- Improved customer service and regulatory compliance
- Reduced maintenance costs
- Increased clarity on roles and responsibilities
- Improved risk management understanding and implementation

Some of the challenges that may be faced when implementing an asset management system in conjunction with an Asset Owner/Asset Manager/Service Provider structured organization include:

- Ensuring alignment, support, and growth of core competencies
- Loss of service provider knowledge within the Asset Manager groups over time
- Tension within the organization created by the required behavioral changes
- Initial transition and implementation costs
- Requirement of strong leadership and compelling business rationale for change
- Need for substantial data integration from previous geographic and functional work groups
- May foster a "them versus us" attitude between manager and service provider groups

4.3 Implementation Approach

In this document, asset management has been characterized as a management system comprised of a number of elements. Implementing these elements requires the development of new processes and supporting tools and enhanced corporate competencies. The implementation of asset management can also involve implementing a new organizational structure such as the Asset Owner/Asset Manager/Service Provider model.

One way to approach implementing elements of asset management is to take a building block approach. Asset Health Review is a logical place to start. Once this is in place, an organization can progress to the Asset Management Ranking Mechanism, then to Capital Optimization, and so on. This approach would also make sense if a member company is unsure about adopting a full asset management system and is only interested in tackling certain elements of asset management to start.

One of the challenges for member companies is determining how to adapt asset management concepts to their particular situation. For example, in implementing a formal Asset Health Review process many decisions must be considered, such as:

- How should the assets be grouped?
- What health indices are appropriate for each asset grouping?
- What existing reports can be incorporated into the review?

Given the nature of the task, a “learning by doing” approach can work well. In one example, a member company formed a small core team to learn about asset management concepts and do the initial ground work to determine how each concept could be implemented in their company. This team then engaged the business department that would eventually own the new process, transferred the knowledge they had gained to the appropriate members of the department, and facilitated the first application of the new process. The business department then took custody of the new process and worked to refine and improve the process, while the core team moved on to tackle the next asset management element.

An alternate approach to implementing asset management could be through structural changes within the organization to promote and facilitate an asset management focus. These structural changes could include the creation of organizational positions with accountability for some or all asset management system elements. As an example, accountability could be assigned for maintenance optimization for a selected asset or group of assets. To meet objectives, processes would need to be developed, requirements for data would need to be set, and systems would need to be specified to improve the ability to optimize maintenance. Accountability should include control over planning and budget for the assets in question.

Regardless of the implementation approach, it should be noted that structural changes alone or asset management system elements alone may not be sufficient. Implementing a successful asset management system will inevitably involve both system elements and organizational structure considerations.

4.4 Asset Management Information System (AMIS)

Successful implementation of an asset management system requires the collection and integration of asset data. Companies may have a variety of paper-based or computer applications managed by individual departments to satisfy the corporate objectives and goals in their respective areas of operation. Data integration from these various paper-based or computer applications is a particularly important consideration. The concept of an AMIS is to have the appropriate system or combination of systems to automate the collection, integration, and organization of asset data for improved decision making.

An AMIS needs to have the capability to support the asset management system. In particular, it needs to have the capability to support the distinguishing elements outlined in section 2 of this document. The core components of an AMIS would include:

- Asset Registry (asset information)
- Work History Collection (work orders) – see “what data to collect”
- Proactive Maintenance management
- Reporting ability

An AMIS is an essential tool to collect and organize data into useful information and to gain knowledge that can be used to more effectively manage assets. As such it could be integrated with other sources of information such as:

- Standards (job plans, safe work procedures, repair procedures, emergency response plans, etc.)
- Risk analysis
- Planning and scheduling
- Inventory/Material management
- Human Resource management
- Billing
- Accounting/Financial
- GIS
- Meter Management
- CAD (drafting)
- Mobile Dispatching
- Incident Tracking
- Contract Management
- Service Management
- Procurement Management
- Metrics or Key Performance Indicators
- Data Analysis and Graphing

4.5 Work Management

Work Management, the process by which a company actually performs work on its assets, can be considered an integral part of the asset management system. The scope of this guiding document does not cover a detailed discussion of Work Management. Also, most member companies already have some form of Work Management in place. Therefore, this guiding document will only highlight the important supporting role of Work Management in the asset management system.

Work Management usually includes six key components: work identification, planning, scheduling, assignment or dispatching, execution, and completion. A work management system generally uses work orders to manage the various work activities and to gather data regarding the cost and other details of the completed activities. The job instructions on the work orders should be aligned to the company's standard practices, providing consistent and safe work procedures. The data collection should be aligned to support the information needs of the asset management system. Asset management techniques like life cycle cost analysis and maintenance optimization set the strategies used to optimally manage distribution assets. Work management supports the planning and execution of these strategies.

4.6 Supply Chain Management

Supply chain management, which includes components such as inventory management, materials management, and the procurement process, can also be considered an integral part of the asset management system. It supports maintenance optimization by ensuring the right materials for the execution of maintenance are available when required. It contributes to optimizing the life cycle costs of assets by procuring the right assets at the beginning of the life cycle.

4.7 Use/Relevance of PAS 55 During Implementation of Asset Management

One approach for the development of an asset management system in our industry is to use the model established in the British Standards Institute's publicly available specification, PAS 55. While this specification was devised to meet the needs of a number of asset intensive industries, its original application began in deregulated water and wastewater utilities in the UK to ensure that water assets were being managed in a way that served and protected the public interest as well as the interests of private shareholders. However, it contains many useful elements that are applicable to any organization that manages large physical assets. PAS 55 is currently being used in other industries.

PAS 55 provides one possible framework for an asset management system, however its wholesale adoption, in its entirety, to the Canadian Gas Delivery industry may not be appropriate. Each organization would need to assess the elements, incorporate their company's nomenclature and culture, and determine what level of adoption is appropriate.

We recognize that PAS 55 is the only known published specification for the optimized management of physical assets and is, therefore, an important reference source. This guiding document is our attempt to interpret the intent of PAS 55 for the Canadian Gas Delivery Industry.

5.0 Relationship of Asset Management to CSA Z662-07

Overview of CSA Z662-07

The CSA Z662 Standard for Oil and Gas Pipeline Systems is the governing standard for gas pipelines in Canada. It specifies the accepted practices, technical requirements, and terminologies for pipelines and has been developed by a committee of interested experts.

The objective of the CSA Z662-07 is safety. It specifies the essential requirements and minimum technical standards for the design, construction, operation, and maintenance of pipeline systems. CSA Z662-07 Commentary, section 0.1 states that "CSA Z662- 07 presents a collection of requirements for oil and gas pipeline systems to describe what has been accepted as good practice from the standpoint of safety."

A significant majority of the content of CSA Z662-07 contains specific technical criteria specifying what an operating company shall do. These can be design criteria, testing parameters, materials requirements, welding requirements, corrosion protection requirements, or other such technical requirements. Operating companies can measure their pipelines, facilities, or practices against these requirements to assess compliance.

Over the last few years, CSA Z662-07 has begun to introduce a management system approach through a number of non-mandatory annexes.

Annex N was introduced to "provide guidelines for developing, documenting, and implementing a pipeline integrity management program to provide safe, environmentally responsible, and reliable service." While the wording throughout refers to "a pipeline integrity management program", the content of the Annex clearly presents a management system approach.

Annex M was introduced to "provide guidelines for enhancing the management of integrity in gas distribution systems." There were sufficient distinct aspects to gas distribution that this parallel annex was developed with provisions suited to gas distribution. As with Annex N, this Annex M was written with a management system approach.

Also, a new clause (10.2) and a new accompanying non-mandatory annex (Annex A) were added, introducing requirements for a Safety and Loss Management System. Although the entire CSA Z662-07 is a collection of requirements to describe what has been accepted as good practice from the standpoint of safety, previous editions of the Standard offered very little on the subject of safety and loss management systems. Although not explicitly stated in section 10, the CSA Z662-07 Commentary clarifies the intent that the principles of the safety and loss management system should also apply to the entire main body of the Standard. Some jurisdictions have now made these annexes mandatory.

Recognizing that there is duplication and overlap with these three annexes, the Technical Committee of CSA Z662-07 is endeavouring to amalgamate or restructure them. While at this time this work is in progress and the final result of this effort is yet to be determined, it is anticipated that the requirement for a management system for Safety and Loss and also Integrity will remain in CSA Z662-07.

Management System Common Elements

There is no singular definition of what comprises a management system. While general similarities often exist, management systems are tailored to the subject that they are intended to manage. This is the case with asset management, and it is also the case with the management system requirements stipulated in Annex A, M and N of CSA Z662-07. As such, a definitive list of the elements or components of a management system does not exist.

Section 3 of this guiding document presents elements and policies that support asset management. These elements can be found in many management systems. Examples of similarities to requirements found in CSA Z662-07 are outlined below.

Documentation Policy / Process:

Similar to Records above, documentation is core to any management system (CSA Z662 Annex A - A.3.3 Documents and records & A.3.3.2 Control of documents).

Records:

While there will be differences in some required records and similarities or overlap of other records, the record keeping structure and requirements are common (CSA Z662-07 Annex A - A.3.3 Documents and records & A.3.3.3 Control of records).

Management of Change:

Processes for the Management of Change are a common element to management systems (CSA Z662-07 Annex A - A.3.4 Management of change).

Training:

Although the training topics and curriculum requirements of a management system are designed for that particular system, the requirements of training and competency are commonly found in different management systems (CSA Z662-07 Annex A - A.5.2.1 Training and competency).

Risk Management:

Risk management is found in Annex A, and is a major part of the Integrity annexes, M and N (CSA Z662-07 Annex A - A.6.3 Risk management).

Measurement System / Performance Metrics:

The concept of monitoring and measuring is common to management systems (CSA Z662-07 Annex A - A.7 Continual improvement).

Distinguishing Elements of Asset Management

In Section 2, the key elements that distinguish asset management from other management systems were identified and described. The CSA Z662-07 content that relates to these asset management distinguishing elements is explored below.

Asset Health Review:

The CSA Z662-07 does not require, acknowledge, or mention Asset Health Review as it is understood in terms of an asset management system. While an Asset Health Review is not required, conducting one is in no way contrary to CSA Z662-07 and would be in keeping with parts of CSA Z662-07 if health concerns of certain components were identified.

CSA Z662-07 contains several references to the condition of the pipelines. Clause 10.14.1 requires an integrity management program for pipelines “so that they are suitable for continued service.” Elsewhere in CSA Z662-07, there are requirements for valve inspections, inspections of pressure control and pressure relieving devices, cathodic protection, and leak surveys. These activities relate to the condition and, in a broader sense, to the health of the pipeline but they are very focused and limited in scope. They address particular components of a pipeline system but not the whole pipeline, network, or corporate asset class.

Asset Management Ranking Mechanism:

The Asset Management Ranking Mechanism, being a method to assess and rank investment opportunities, is a subject matter not touched on and is outside the scope of CSA Z662-07. CSA Z662-07 can indirectly affect the ranking where one or more projects being ranked are being done to achieve compliance with CSA Z662-07. This would be but one factor that would be considered in the Asset Management Ranking Mechanism.

Capital Optimization:

The CSA Z662-07 is essentially silent on the subject of cost. The word “cost” does not appear in the main body of CSA Z662-07 and is used once in Annex A in the definition of a project. While cost is a consideration of the Technical Committee and Technical Sub-committees in their work developing and updating the CSA Z662-07, it is not carried forth in terms of a requirement in the main body of the code. Capital optimization is about spending dollars wisely while CSA Z662-07 is a technical code and does not address spending decisions.

Life Cycle Costing:

Whether addressing costs on a life cycle basis or through capital optimization, CSA Z662-07 does not have requirements for cost considerations.

Maintenance Optimization:

While CSA Z662-07 has many requirements for maintenance, cost performance in conducting that maintenance is not an issue for CSA Z662-07. Provided the minimum maintenance technical requirements are met, optimization in terms of activities, frequency, or cost is outside the purview of CSA Z662-07. The word “optimize” does not appear in CSA Z662-07.

Long-term Capital Planning:

Long-term capital planning addresses matching capital expenditures to the need for those expenditures presently and in years to come. CSA Z662-07 has no position on capital planning. The focus of CSA Z662-07 is on the technical requirements of the gas pipelines and other plant on which the capital will be spent.

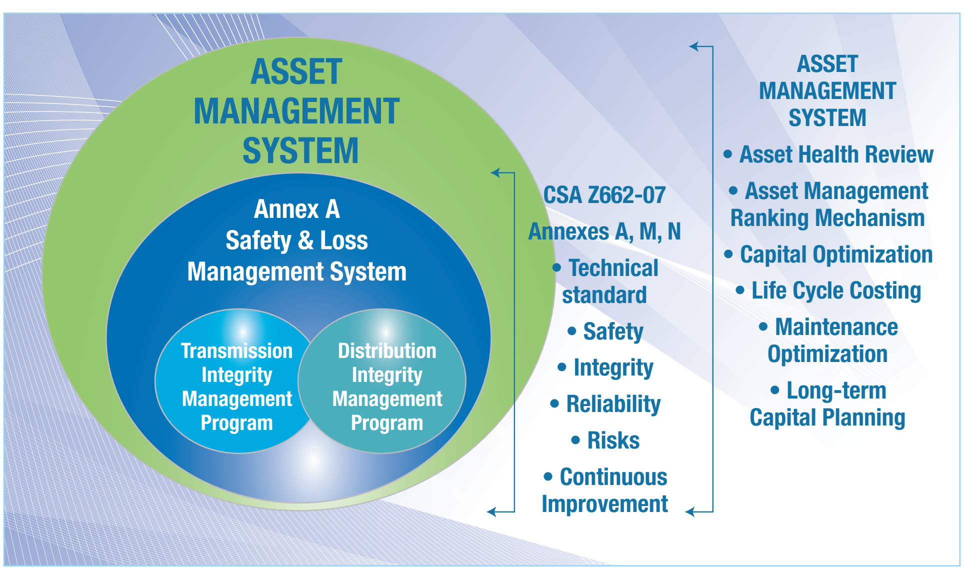
Asset management is focused on balancing costs, risks, and performance, which includes meeting technical requirements. The CSA Z662-07 is focused on technical requirements and safety and, therefore, is complimentary to asset management.

The Safety and Loss Management System and the Integrity Management Program requirements of CSA Z662-07 are laid out as management systems in the annexes. Although the annexes are written to be informative and non-mandatory, the direction is clear that a management system approach is advocated. It should be noted that some jurisdictions have made the annexes mandatory.

The distinguishing elements of asset management are not included in the management systems promoted within CSA Z662-07. However, as there is commonality in several of the supporting elements, there is a synergy possible where one management system incorporating these elements would serve the needs of both.

In summary, there is no conflict between the requirements of CSA Z662-07 and asset management and there are synergies possible for several elements where a management system approach is used for both.

Relationship between Asset Management and CSA Z662 - 07



Appendices

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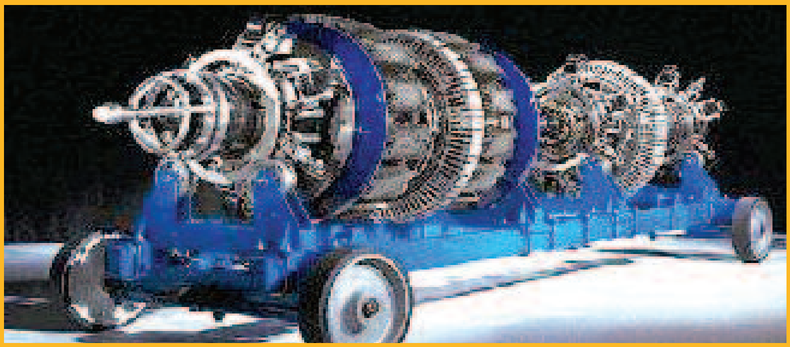
B) International Gas Union (IGU) - Participation

Given that utilities in countries such as the U.K. and Australia are currently more advanced in their adoption of asset management disciplines, it was decided that participation in the IGU working committee on asset management would be beneficial. Accordingly, Lloyd Chiotti, chair of the CGA Asset Management Task Force, joined Working Committee 4 (WOC 4) of the IGU in October 2008.

This committee, which focuses on the distribution sector of the gas industry, had formed a study group in 2007 to survey best practices in asset management amongst IGU member companies. The results of this work were presented at the World Gas Conference held in October 2009.

Even though participation in this committee was limited to the latter part of its work, it was very beneficial, particularly in helping to confirm the task force's interpretation of asset management as it relates to the gas delivery business. As well, a number of papers presented at the World Gas Conference on the subject of asset management have been made available to all task force members. Finally, good contacts have been established with many gas companies around the world, which will provide an ongoing source of valuable information to the CGA



CANADIAN GAS ASSOCIATION
ASSOCIATION CANADIENNE DU GAZ

CANADIAN GAS ASSOCIATION
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Appendix F

GLOSSARY

GLOSSARY

ACESA – *American Clean Energy and Security Act.*

ACP – Annual Contracting Plan.

AEO – Annual Energy Outlook, reporting long-term projections of energy supply, demand, and prices through 2035.

AFUDC – Allowance for Funds used during Construction, which is an allowance for the cost of debt and equity funding of capital projects before they are completed and placed into service and included in rate base; the AFUDC recorded for a project is added to the overall project cost.

AFUE - Annual Fuel Utilization Efficiency.

AIMP - Asset Integrity Management Plan.

Annual demand – the cumulative daily demand for natural gas over an entire year.

Bcf – billion cubic feet.

BCH – BC Hydro.

BCTC – BC Transmission Corporation.

BCUC (British Columbia Utilities Commission) – the BCUC is the provincial body regulating utilities in British Columbia.

BTU – British thermal units.

Burrard Thermal – BC Hydro's Burrard Thermal Generating Station.

CEA – *Clean Energy Act.*

CGA – Canadian Gas Association.

CIAC – Contributions in aid of Construction.

CIS – Customer Information System.

CMHC – Canada Mortgage & Housing Corporation.

CNG – Compressed Natural Gas.

Commission – British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia.

CPCN (Certificate of Public Convenience and Necessity) – a certificate obtained from the British Columbia Utilities Commission under Section 45 of the Utilities Commission Act for the construction and/or operation of a public utility plant or system, or an extension of either, that is required, or will be required, for public convenience and necessity.

CPR (Conservation Potential Review) – a study completed to identify opportunities for energy savings across gas and electrical energy delivery infrastructures and improvements to overall energy utilization efficiency.

CTS – Coastal Transmission System.

Daily demand – the amount of natural gas consumed by Terasen Gas' customers throughout each day of the year.

Demand forecast – a prediction of the demand for natural gas into the future for a given period and under a specified set of expected future conditions.

Demand side, Demand Side Management (DSM) – defined as "any utility activity that modifies or influences the way in which customers utilize energy services".

DES – District Energy Systems.

Design-day, design hour demand (see also: peak day) – the maximum expected amount of gas in any one day or hour required by customers on the TGI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. For transportation customers, the design-day is equivalent to the firm contract demand. (See also: peak day).

DHW – Domestic Hot Water.

DLE – Diesel Litre Equivalents.

EEC – Energy Efficiency and Conservation.

EF – Efficiency Factor.

EIA – Section of the U.S. Department of Energy providing statistics, data, analysis on resources, supply, production, consumption for all energy sources.

GDP – Gross Domestic Product.

GHG – Greenhouse gas.

GJ – Gigajoule – a measure of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).

GLE – Gasoline litre equivalent.

GLJ – GLJ Petroleum Consultants Ltd. is a private petroleum industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis.

GSHP – Ground Source Heat Pumps - a form of geo-exchange system.

GTN – Gas Transmission Northwest.

GWh – giga-watt hours, equal to 1 million kilowatt-hours

HDD – Heating degree day – a measure of the coldness of the weather experienced. The number of heating degree days for a given day is calculated based on the extent to which the daily mean temperature falls below a reference temperature, 18 degrees Celsius.

Huntingdon/Sumas – gas flow regulating stations on either side of the British Columbia / US border through which much of the regional gas supply is traded.

I-5 Corridor – the natural gas regional market area served by infrastructure located along Interstate 5 in the north western US. The I–5 Corridor includes B.C.'s Lower Mainland and Vancouver Island, Western Washington and Western Oregon.

ICP – Island Cogeneration Project – a cogeneration plant located at Elk Falls, Campbell River supplying electricity and thermal energy on Vancouver Island.

ILM transmission project – interior to Lower Mainland electrical transmission project being developed by BCTC to serve BC Hydro Lower Mainland load.

IMP – Integrity Management Plans.

IRP – Integrated Resource Plan – a document that details the resource planning process and outcomes that guide a utility in planning to serve its customers over the long term.

ITS – Interior Transmission System.

JPS – Jackson Prairie Storage.

kW – kilowatt – one thousand watts; the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light 10 100-watt light bulbs.

kWh – kilowatt hour – one thousand watts used for a period of one hour; the basic unit of measurement of electric energy. On average, residential customers in B.C. use about 10,000 kWh per year.

LML – Vancouver Lower Mainland area.

LNG (Liquefied natural gas), LNG storage – natural gas stored under high pressure turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state; however, specialized storage facilities must be constructed.

Load – the total amount of gas demanded by all customers at a given point in time.

LTAP – BC Hydro's Long Term Acquisition Plan, which identifies the preferred resources, both supply and demand that the utility intends to acquire over the long-term to serve the growing demand for electricity in BC.

LTRP – Terasen Utilities' Long Term Resource Plan, which examines future demand and supply resource conditions over the next 20 years and recommends actions needed to ensure customers' energy needs are met over the long term.

MFD – Multi-Family Dwelling.

MMBtu – one million Btu.

MMcf – one million cubic feet.

MMcfd – one million cubic feet per day.

MOP – Maximum Operating Pressure.

Mt – Million Tonnes.

MW – mega watt – one million watts; one thousand kilowatts. A unit commonly used to measure both the capacity of generating stations and the rate at which energy can be delivered.

NAT GAS Act – *New Advanced Transportation to Give Americans Solutions Act.*

NEB – National Energy Board.

NG – Natural Gas.

NGTL – Nova Gas Transmission Limited.

NGV – Natural Gas Vehicles.

Normal demand (also called annual demand) – when considering historical normal demand, this is the actual demand experience that has been adjusted to account for weather that has been colder/warmer than normal. The expected demand during a year of normal weather conditions. When considering forecast normal demand, this is the expected demand under normal weather conditions. Normal weather conditions are based on a rolling 10 year average of heating degree days experienced during each of the 10 years.

NPCC – Northwest Power and Conservation Council.

NRCan – Natural Resources Canada.

NREL – National Renewable Energy Laboratory.

NWGA – Northwest Gas Association is a trade organization of the Pacific Northwest natural gas industry. Its members include six natural gas utilities, including Terasen Gas, serving communities in Idaho, Oregon, Washington and British Columbia, and three interstate pipelines that move natural gas from supply basins into and through the region.

NWP – Northwest Pipeline.

NWPCC – Northwest Power and Conservation Council.

O&M – Operating and Maintenance.

OEM – Original Equipment Manufacturer.

Peak day, peak demand, peak day demand – the maximum expected amount of gas in any one day or hour required by customers on the TGI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. For transportation customers, the design-day is equivalent to the firm contract demand. (See also: design day)

PJ – petajoule – equal to 1000 terajoules or 10^6 gigajoules.

PNW – Pacific Northwest Region.

PNWER – Pacific Northwest Economic Region.

Portfolio, resource portfolio, supply portfolio – selected supply and / or demand resources that, when grouped together, can meet the future demand and supply needs of a service area.

PSE – Puget Sound Energy.

psig – pounds per square inch gauge.

QUEST – Quality Urban Energy Systems of Tomorrow.

Rate volatility – the amount to which natural gas rates fluctuate and the frequency of those fluctuations.

Resources – demand side and supply side means available to meet forecasted energy needs. Examples of supply side resources within the context of the Resource Planning process are Pipeline Looping, Compression and Storage.

REUS – Residential End Use Study.

RIB – BC Hydro's Residential Inclining Block rate.

RIM – Rate Impact Measure.

RPAG – Resource Plan Advisory Group.

RPS – Renewable Portfolio Standards.

RRA – Revenue Requirement Application.

SCP – Southern Crossing Pipeline.

SFM – single family dwelling.

Tcf – trillion cubic feet.

TCPL – TransCanada Pipeline.

Terasen Utilities – collectively referring to TGI, TGVI, and TGW.

TES – Terasen Energy Services.

TGI – Terasen Gas Inc.

TGVI – Terasen Gas (Vancouver Island) Inc.

TGW – Terasen Gas (Whistler) Inc.

TRC – Total Resource Cost.

TSA - Transportation Service Agreement.

TJ – terajoule – equal to 1000 gigajoules.

UBCM - Union of British Colombia Municipalities.

UCA Act – *Utilities Commission Amendment Act*.

Utilities – see Terasen Utilities.

VIGJV (Vancouver Island Gas Joint Venture) – a joint venture of industrial customers (primarily large mills) on Vancouver Island who contract for transportation services as a single entity.

WCI – Western Climate Initiative.

WCSB – Western Canadian Sedimentary Basin.

WREZ – Western Renewable Energy Zones.