LAND USE REGULATION COMMISSION
APPLICATION FOR
PROPOSED METEOROLOGICAL TOWER INSTALLATION
ASSOCIATED WITH THE
SISK WIND POWER PROJECT

KIBBY AND CHAIN OF PONDS TOWNSHIPS,
FRANKLIN COUNTY, MAINE

March 2009

Submitted by:

TransCanada Maine Wind Development
8th Floor, Yonge Street
Toronto, Ontario, Canada M5E 1J4

TransCanada
In business to deliver

Prepared by:

TRC Engineering
249 Western Avenue
Augusta, Maine 04330

TRC

TransCanada
In business to deliver

55 Yonge St., 8th Floor
Toronto, ON M5E 1J4

tel 416.869.2145
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email christine_cinnamon@transcanada.com
web www.transcanada.com

March 12, 2009

Ms. Marcia Spencer-Famous
Department of Conservation
Land Use Regulation Commission
22 State House Station
Augusta, Maine 04333-0022

Subject: ***Application for Proposed Meteorological Measurement Towers Associated with the Sisk Wind Power Project***

Dear Ms. Spencer-Famous:

Enclosed please find ten copies of an application for proposed meteorological towers (met towers) associated with the Sisk Wind Power Project. A single application is submitted, with work proposed in Chain of Ponds and Kibby Townships (four met towers and associated access trails).

TransCanada is pleased to provide this information to you. Please do not hesitate to contact either Dana Valleau of TRC Environmental Corporation (207-621-7093; dvalleau@trcsolutions.com) or me (416-869-2145; christine_cinnamon@transcanada.com) if you have any questions, require additional information, or have concerns we can address.

Best Regards,

Christine Cinnamon
Environmental Manager, Power Generation and Development

LIST OF CONTENTS

Note that Exhibits are not consecutively numbered because only certain required exhibits are relevant to this application.

Tracking No.	For office use
Permit No.	

Maine Land Use Regulation Commission
Department of Conservation

Permit Application

for residential and non-residential development

1. APPLICANT INFORMATION

Applicant Name(s)	Daytime Phone	FAX	E-mail
Christine Cinnamon, TransCanada Maine Wind Development	(416)-869-2145	(416)-869-2056	christine_cinnamon@transcanada.com
Mailing Address 8th floor, 55 Yonge Street, Toronto, Ontario, Canada M5E IJ4			

2. AGENT AUTHORIZATION AND APPLICANT SIGNATURES

Agent Name	Daytime Phone	FAX	E-mail
Dana Valleau, TRC Environmental Corporation	(207)-621-9093	(207)-621-7001	dvalleau@trcsolutions.com
Mailing Address 249 Western Avenue, Augusta, Maine 04330			

All persons listed on the deed, lease or sales contract as owners or lessees of the property must read the statement and sign below.

I hereby authorize the above-listed individual to act as my legal agent in all matters relating to this permit application. I have personally examined and am familiar with the information submitted in this application, including the accompanying exhibits and supplements, and to the best of my knowledge and belief, this application is true and accurate. I understand that I am ultimately responsible for complying with all applicable regulations and with all conditions and limitations of any permits issued to me by LURC.

Applicant Signature(s) ______________________ Date ________

______________________ ________

3. PROJECT LOCATION AND DESCRIPTION

Describe in detail what you are proposing and the purpose of the work to be accomplished (use additional paper if you need more space).

Four temporary meteorological (met) towers are proposed to be installed for the purposes of wind data collection for continued feasibility assessment for the proposed Sisk Mountain Wind Power Project. The met towers would also be used for installation of ecological data collection equipment. Level A mineral exploration and associated access is also proposed. See Attachment A - Project Location and Description for additional information with regard to the proposed installation and the overall project being assessed.

Property Location		
Township, Town or Plantation: Kibby and Chain of Ponds Townships	County: Franklin	Lessor and Lease Lot Numbers (check your lease): See Attachment A
Tax Plan and Lot Numbers (check your tax bill): See Attachment A		Book and Page Numbers (check your deed): See Attachment A

Lot Size (in acres, or in square feet if less than 1 acre): See Attachment A	Zoning (check a LURC map - list all subdistricts covering your property): P-MA, P-SL
Road Frontage. Is your property adjacent to any roads, streets or other rights-of-way (including any camp roads)? ☐ Yes ☐ No	Water Frontage. Is there a lake, pond, river, stream, brook, or other water body on or adjacent to your lot? ☒ Yes ☐ No
If yes, write the name and frontage (in feet) for each road: N/A - Forest management roads and trails provide access to proposed work sites (see Exhibit A)	If yes, write the name and frontage (in feet) for each water body: Various unnamed first and second order streams as depicted on location maps (Exhibit A).
If no, describe how you access your property:	

4. LAND DIVISION HISTORY

Using your deed as a starting point, trace the ownership history and configuration changes of your property back to 20 years from today. List all changes in ownership and all divisions of those lots from which your property originated (use additional paper if you need more space).

Description of Transaction (including seller's and buyer's names)	Date of sale or lease	Lot size
See Attachment A		

5. EXISTING USES, STRUCTURES AND FEATURES N/A

Existing Use: What is the current use of your property?
□ Residential □ Residential with Home Occupation □ Commercial or Industrial □ Public or Institutional □ Other: ____________

Existing Structures: Are there any structures on your property? □ Yes □ No
If yes, fill in a line on the table below for each structure on your lot (use additional paper if necessary):

Type of structure (dwelling, garage, deck, porch, shed, etc.)	Year built	Exterior dimensions (LxWxH)	Number of:		Type of Foundation (full basement, slab, post, etc.)	Distance (in feet) of structure from nearest:				
			Bedrooms	Plumbing or water fixtures		Road	Property line	Lake or pond	River or stream	Wetland

Other Existing Features: If any of these features exist on your property, check off the feature and answer the appropriate questions.

□ Driveways
Dimensions (LxW): ____________
Shared driveway? □ Yes □ No
Distance of driveway (in feet) from nearest:

Property line	Lake or pond	River or stream	Wetland

□ Parking areas
Number of parking areas: ____________
Dimensions (LxW): ____________
Distance of parking areas (in feet) from nearest:

Road	Property line	Lake or pond	River or stream	Wetland

□ Water supply
What type of water supply serves your property?

□ Signs
Number of signs: ____________
Dimensions (LxWxH): ____________
Are any signs lighted? □ Yes □ No
Distance of signs (in feet) from advertised structure or activity: ____________

□ Exterior lighting
List the fixtures that have been installed to illuminate your property:

Type of bulb	Watts	Date fixture installed	Cutoff fixture?	Motion activated?
			□	□
			□	□
			□	□

6. CHANGES TO EXISTING STRUCTURES OR FEATURES N/A

Will you be expanding, reconstructing, relocating, or otherwise altering any existing structures on your property? □ Yes □ No
If yes, fill in a line on the table below for each structure proposed to be altered (use additional paper if necessary):

Structure to be altered (dwelling, garage, porch, shed, driveway, sign, etc.)	Proposed alterations (check all that apply)						New exterior dimensions (LxWxH)	New number of:		Distance (in feet) of altered structure from nearest:				
	Expand or add on	Reconstruct or replace *	Permanent foundation	Relocate	Enclose deck or porch	Other **		Bedrooms	Plumbing or water fixtures	Road	Property line	Lake or pond	River or stream	Wetland
	□	□	□	□	□	□								
	□	□	□	□	□	□								
	□	□	□	□	□	□								
	□	□	□	□	□	□								

* Reconstruction or installation of a permanent foundation. If you are reconstructing an existing structure, or if you are installing a permanent foundation beneath an existing structure:

- Has the existing structure been damaged, destroyed or removed from your property? □ Yes □ No
  If yes, provide the date the structure was damaged, destroyed or removed: ____________
- If the reconstructed structure or permanent foundation will not meet LURC's minimum setback requirements from property lines, roads, water bodies or wetlands, explain what physical limitations (such as lot size, slope, location of septic system, etc.) prevent the structure or foundation from meeting such setbacks:

** Other. If you selected "Other" from the table above, describe in detail the type of alteration you are proposing (use additional paper if needed):

7. PROPOSED USES, STRUCTURES AND FEATURES

Proposed Use: What is the proposed use of your property?

☐ Residential ☐ Residential with Home Occupation ☐ Commercial or Industrial ☐ Public or Institutional ☒ Other: Meteorological towers

New Structures: Will you be constructing or installing any new structures on your property? ☒ Yes ☐ No

If yes, fill in a line on the table below for each new structure.

Type of structure (dwelling, garage, porch, shed, etc.)	Exterior dimensions (LxWxH)	Number of: Bedrooms	Number of: Plumbing or water fixtures	Type of Foundation (full basement, slab, post, etc.)	Distance (in feet) of structure from nearest: Road	Property line	Lake or pond	River or stream	Wetland
Meteorological towers	See Attachment B	0	0						

Other Proposed Features: If you are proposing to add any of these features, check off the feature and answer the appropriate questions:

☐ Driveways N/A

Dimensions (LxW): ______

Shared driveway? ☐ Yes ☐ No

Distance of driveway (in feet) from nearest:

Property line	Lake or pond	River or stream	Wetland

Will the driveway have a slope greater than 8%? ☐ Yes ☐ No

Will the driveway cross any flowing water? ☐ Yes ☐ No

If yes, what type of crossings will be used? ☐ Bridge ☐ Culvert

Will crossings be sized at least 2½ times the cross-sectional area of the flowing water? ☐ Yes ☐ No

☐ Water supply N/A

What type of water supply will serve the property?

☐ Exterior lighting N/A

List the fixtures that will be installed to illuminate your property:

Type of bulb	Watts	Cutoff fixture?	Motion activated?
		☐	☐
		☐	☐
		☐	☐

☐ Parking areas N/A

Number of parking areas: ______

Dimensions (LxW): ______

Distance of parking areas (in feet) from nearest:

Road	Property line	Lake or pond	River or stream	Wetland

☐ Signs exceeding LURC standards N/A

Number of signs: ______

Dimensions (LxWxH): ______

Will any signs be lighted? ☐ Yes ☐ No

Distance of signs (in feet) from advertised structure or activity: ______

What features of the signs exceed LURC standards?

Why do the signs need to exceed LURC standards?

Will the signs be a hazard to traffic? ☐ Yes ☐ No

How will the signs' design elements (color, bulk, materials, height, etc.) be compatible with the property and fit harmoniously into the surroundings?

8. SEWAGE DISPOSAL FOR NEW AND ALTERED STRUCTURES

Will any proposed new or altered structures include bedrooms, bathrooms or plumbing/water fixtures, or otherwise generate waste water? ☐ Yes ☒ No

9. WETLAND ALTERATIONS

Will your proposal alter any amount of land that is a mapped P-WL subdistrict or any ground below the normal high water mark of a lake, pond, river, stream, or intertidal area? ☐ Yes ☒ No

See Supplement S-3

Will your proposal alter an acre or more of any land area, either upland or wetland? ☐ Yes X No

10. FEMA FLOOD ZONING

Are you proposing first-time development or making substantial improvements to any existing development within a mapped FEMA floodplain? ☐ Yes ☒ No

11. VEGETATION CLEARING

Will your project involve any clearing of vegetation? (If yes, answer the following questions) ☒ Yes ☐ No

- Total area of clearing: See Attachment B ________ sq. ft.
- Distance between edge of cleared area and the nearest:

Road	Property line	Lake or pond	River or stream	Wetland

12. BUFFERING IN PROSPECTIVELY ZONED AREAS

Is your property located in a development subdistrict within a prospectively zoned area? ☐ Yes ☒ No

- If yes, how wide are any existing wooded buffers (as measured at the narrowest point) between existing and proposed structures on your property and the nearest:

Road	Side property line	Rear property line	Subdistrict boundary (if in D-ES or D-CI)

- Do these buffers or any other features of your property screen the proposed development from view from the road and adjacent properties? ☐ Yes ☐ No

13. EROSION AND SEDIMENTATION CONTROL

- Total area of new or expanded soil disturbance: See Attachment B ________ sq. ft.
- Distance between the disturbed area and the nearest:

Road	Property line	Lake or pond	River or stream	Wetland

- If soil disturbance will occur within 250 feet of a water body or wetland, what is the average slope of the land between the disturbed soil and the normal high water mark or upland edge? Slope: <10 %
- Will soil disturbance occur when the ground is frozen or saturated? ☒ Yes ☐ No
- Will soil disturbance occur (a) in water bodies, wetlands, natural drainage systems, or water crossings; (b) on slopes exceeding 15%; or (c) in other sensitive areas? ☒ Yes ☐ No

  If yes, how will you stabilize disturbed areas and minimize the amount and duration of soil exposure?

  See Exhibit H

- Will existing catch basins and culverts on or near the property be protected from sediment by the use of hay bale check dams, silt fences or other effective measures? ☒ Yes ☐ No
- Will topsoil be stripped from the property? ☐ Yes ☒ No

  If yes, will the topsoil be stockpiled at least 100 feet from water and wetlands? ☒ Yes ☐ No
- Will all disturbed areas and stockpiled soils be effectively stabilized at the end of each workday? ☒ Yes ☐ No
- Will any fill used be free of hazardous or toxic materials, debris, trash and rubbish? ☒ Yes ☐ No
- What will you do (during site preparation, construction, cleanup, and post-construction) to stabilize disturbed soil and prevent sediment from entering water, wetlands, natural drainage systems, catch basins, culverts or adjacent properties?

  See Attachment B and Exhibit H

- What provisions will you make for the continued maintenance of all proposed erosion and sedimentation control measures?

  See Exhibit H

- Provide a general timeline of construction activities on your property, including clearing, grading, construction and landscaping:

  See Attachment B

14. ADDITIONAL INFORMATION

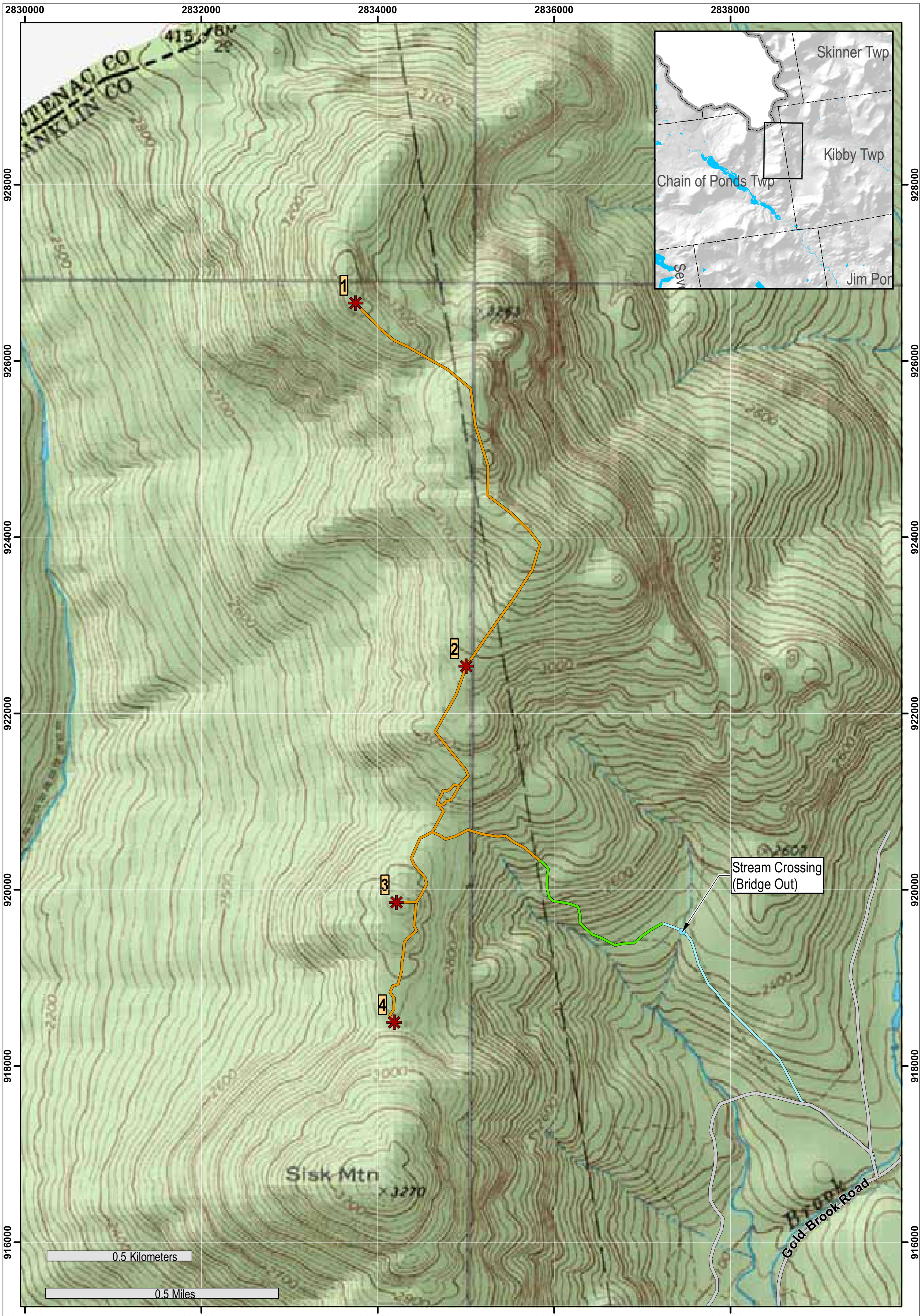
State any facts that further explain your proposal or may help us in our review of your application (Use additional paper if needed).

15. REQUIRED FEES, EXHIBITS AND SUPPLEMENTS

Submit all necessary fees, exhibits and supplemental information with this application, as described in the instructions.

EXHIBIT A:

LOCATION MAP



Potential Met Tower Sites	Maintained Road
Stream Crossing	Existing Winter Road
	Existing Skid Trail
	Potential New Access Trail

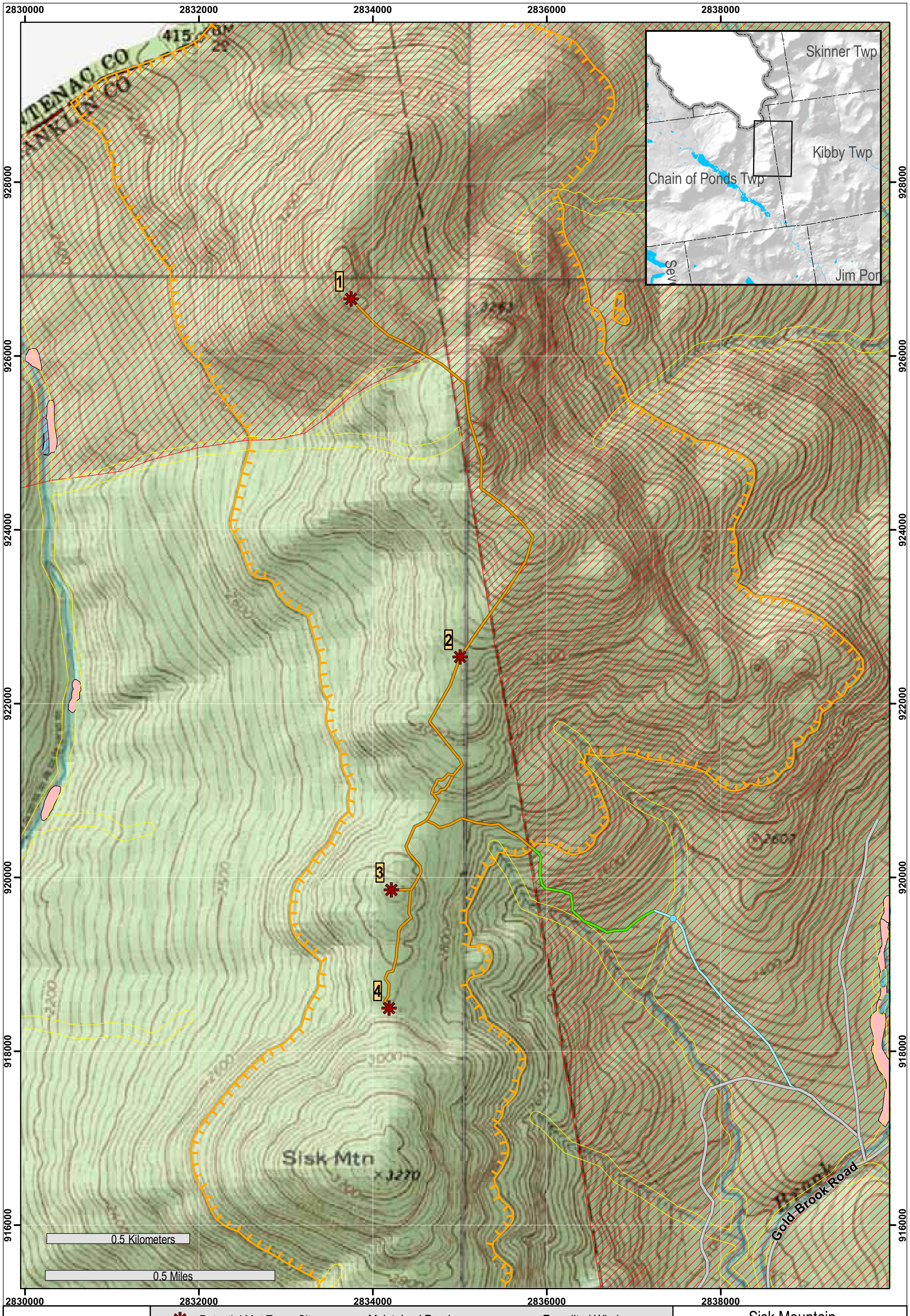
Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

Sisk Mountain
Proposed Meteorological Tower
Sites and Access

EXHIBIT: A-1

249 Western Ave
Augusta, ME 04330

Created:
3/10/2009



Sisk Mountain
LURC Zones and Expedited
Windpower Project Permitting Area

EXHIBIT: A-2

249 Western Ave
Augusta, ME 04330

TRC

Created:
3/10/2009

Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

EXHIBIT B:

DEED, LEASE OR SALES CONTRACT

LICENSE AGREEMENT
Wind Resource Evaluation

THIS LICENSE AGREEMENT is made and entered into this 22nd day of December, 2008 (the "Effective Date") by and between Kennebec West Forest, a Delaware Limited Liability Company having a place of business at 40 Rowes Wharf, Boston, Massachusetts 04112 ("Licensor"), and TransCanada PipeLine USA Inc., a Nevada corporation with a place of business at 110 Turnpike Rd, Ste. 203, Westboro, MA 01581 ("Licensee").

WITNESSETH:

WHEREAS, Licensor is the owner of a certain lot or parcel of land located in Chain of Ponds Township, Franklin County, Maine more particularly described in the deed referenced in Exhibit A attached hereto ("Licensor's Land"); and

WHEREAS, Licensee wishes to use that portion of Licensor's Land described on Exhibit B attached hereto (the "Premises") for access and egress, for its and its contractors' personnel, vehicles and equipment, and for the installation, maintenance, operation, and repair of a meteorological tower and other related equipment, as more specifically described in Exhibit C attached hereto (the "Evaluation Equipment") for the purpose of evaluating the wind resource available at and near the Premises and other uses described on Exhibit C (collectively, the "Permitted Uses"); and

WHEREAS, Licensor is agreeable to allowing Licensee to use the Premises for the Permitted Uses on the terms and conditions set forth herein; and

WHEREAS, Licensor and Licensee intend to negotiate and, upon mutual agreement, execute a further agreement with regard to Licensee's use of Licensor's Land and the Premises (the "Option Agreement") which would supersede and replace this License.

NOW THEREFORE, in consideration of the License Fee set out in Section 2 below and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Licensor and Licensee hereby agree as follows:

1. **Term:** The term of this License (the "Term") shall be for three years, beginning on the Effective Date and ending at the earlier of; (a) 5:00 p.m. on the third anniversary of the Effective Date or (b) execution and delivery of the Option Agreement, unless earlier terminated as set forth herein

2. **License Fee:** Licensee shall pay to Licensor an annual License Fee of [redacted] on the Effective Date and on each anniversary of the Effective Date during the Term. Any License Fee paid during a year of the Term during which the Option Agreement is executed shall be credited to any amounts owing by Licensee pursuant to the Option Agreement.

3. **Permits:** Promptly after the Effective Date, Licensee shall apply for any and all governmental permits, authorizations and approvals necessary for the construction and maintenance of the Evaluation Equipment, and for use of the Premises as contemplated herein (collectively, the "Permits") The Licensor shall cooperate with and support the Licensee in its application for Permits, at no cost to Licensor (and Licensee shall reimburse Licensor for all reasonable costs and expenses associated with the same) The Licensor shall provide any and all non-confidential information in its possession, to the extent commercially reasonable, as requested by the Licensee, that is required to support such Permit application In the event Licensee fails to obtain any of the Permits prior to the 180th day following the Effective Date (the "Permit Date"), then this License shall terminate automatically on the Permit Date. Notwithstanding the foregoing, if the failure of Licensee to obtain any of the Permits is solely the result of a delay in processing, making a final determination upon, or issuing a Permit by the permitting authority, and not due to any failure on the part of Licensee to timely file, submit, or provide materials, data, or other information requested by the permitting authority, then the Permit Date shall be extended for a period necessary to allow the permitting authority to process, make a final determination upon, and issue such Permit, provided that in no event shall such extension exceed 180 days.

4. **Use; Restoration of Premises:** Licensor hereby grants Licensee the exclusive right to use the Premises for the Permitted Uses for the Term Except for the Permitted Uses or as set forth on Exhibit C, Licensee shall not make any improvements to the Premises or Licensor's Land without the prior written consent of Licensor, which may be withheld or conditioned in Licensor's sole discretion. The Evaluation Equipment and all other improvements and equipment of Licensee shall remain the property of Licensee during the Term Within 30 days after the expiration of the Term or earlier termination of this License, Licensee shall remove all Evaluation Equipment and other property of Licensee, and shall restore the Premises to substantially the same condition it was in prior to the Effective Date; provided that Licensee shall not be required to replace any trees or bushes removed by it in the exercise of its rights under this License Any Evaluation Equipment or other property of Licensee not removed within 30 days after the expiration of the Term or earlier termination of this License shall immediately, and without the necessity of any further action on the part of Licensor or Licensee, become the property of Licensor

5. **Conduct of Operations:** At all times during the Term, Licensee shall keep the Premises in a clean and sanitary condition, and all improvements thereon shall be properly maintained and kept up. Licensee shall at all times comply with all applicable laws, rules, and regulations, and the conditions of any and all Permits, approvals, authorizations and/or consents related to Licensee's use of the Premises Licensee agrees to conduct his operations on said Lands in a prudent manner and to take every reasonable precaution to prevent accidents of any nature

6. **Vegetation Clearing:** Subject to applicable laws, regulations, and, if provided to Licensee prior to Licensee's commencement of clearing on the Premises, private agreements and voluntary sustainability programs adopted by Licensor, Licensee may clear the Premises, including the cutting of timber, for the purpose of the Permitted Uses, but may not otherwise cut any timber, or permit any timber to be cut, on the Premises and agrees to conduct all of its

operations on the Premises so as to otherwise prevent damage to timber growing thereon, or on Licensor's Land, by fire or otherwise and further agrees to assist in the suppression and prevention of fires on Licensor's Land Licensee shall pay to Licensor the then-current market value (as reasonably determined by Licensor) of any and all timber, trees, and other vegetation cut or cleared in connection herewith

7. **Licensor's Retained Rights:** This License shall not in any way affect the right of Licensor to enter upon the Premises on foot, or with horses and/or motor vehicles, at any and all times for any purposes whatsoever; nor shall it affect the right of Licensor to use and enjoy the Premises fully, whether in connection with forestry work, land management, logging operations or otherwise, except and unless such use would be incompatible with the uses of the Premises by Licensee herein If any of the Evaluation Equipment is damaged by the Licensor, its guests, employees, contractors, or invitees, Licensor shall repair such damage at its sole expense and to the reasonable satisfaction of the Licensee

8. **Hunting Rights:** All game and hunting rights on the Premises are reserved to Licensor and Licensee shall not have the right to do or permit any hunting on or about the Premises

9. **Non-interference:** Except as set out in Section 6, Licensee shall not make any clearing on the Premises and shall not dam or raise the natural water level of any lakes, ponds or streams located thereon Licensee shall not interfere with any dams, logs, booms, boats, tools or other property belonging to Licensor located on the Premises or Licensor's Land. Licensee shall not conduct its operations (including the operation of motor vehicles) or allow its guests, employees, contractors, or invitees to conduct their operations or operate motor vehicles in such a manner as to interfere with the operations of Licensor, or its servants, agents, employees or contractors. Licensee shall not block or allow the blocking of any roads If any roads on or serving the Premises are damaged or destroyed by Licensee, its guests, employees, contractors, or invitees, Licensee shall repair any such damage at its sole expense and to the reasonable satisfaction of Licensor

10. **Access:** Licensee shall be permitted to use that portion of the private road known as Gold Brook Road located on Licensor's Land and providing access to the Premises from State Route 27, for pedestrian and vehicular ingress and egress to and from the Premises, including with heavy machinery and for the transportation of the Evaluation Equipment; provided, however, that Licensee shall be responsible for the cost and expense of repairing any damage to said road caused by Licensee's use thereof Alternative or additional access to the Premises by Licensee shall be over such roads, ways, or routes as may be mutually agreed upon by Licensor and Licensee from time to time

11. **Indemnity:** Licensee agrees to indemnify, defend, and hold harmless Licensor from and against any and all loss, damage, liability, cost or expense, including reasonable attorney fees, relating to or arising from Licensor's use of the Premises or in any manner resulting from the granting or existence of this License, provided that Licensee shall not be liable to Licensor for any special or punitive damages (whether in contract, tort or otherwise).

12. No Warranties: No warranty or representation of any kind whatsoever is made by Licensor to Licensee as to Licensor's title to the Premises or as to the adaptability or suitability of the Premises for the purposes and uses herein set forth.

13. Insurance: Licensee agrees to secure and maintain public liability insurance, including all contractual liability, in connection with the use of the Premises in such amounts and with such insurance companies as shall be agreeable to Licensor. Licensor further agrees that it will require any such insurance companies to submit authenticated copies of such insurance policies to Licensor, which policies must contain guaranteed cancellation clauses providing that the insurance company will notify Licensor at least thirty (30) days prior to any cancellation, change in, or reduction of the coverage shown therein.

14. Default: In the event of a default by Licensee in any of its obligations hereunder, Licensor shall have the right to terminate this License upon 30 days written notice to Licensee if Licensee fails to cure such default within such 30 day period. Any act or omission in contravention of any provision hereof by any guest, agent, invitee, contractor or employee of the Licensee shall be deemed to be a default by the Licensee under such provision. Licensee shall be liable for all damages which Licensor may sustain by reason of such default, including without limitation all attorney fees and other expenses. In addition to the foregoing, Licensor reserves all other rights and remedies available to it at law and/or in equity.

15 Assignment: This License may not be assigned in whole or in part without the prior written consent of Licensor, which may be withheld or conditioned in Licensor's sole discretion.

16. Notices: All notices, requests, demands, and other communications required or permitted to be given under this License shall be in writing and shall be either served (i) personally on the party to whom notice is to be given (in which case such notice shall be deemed to have been duly given on the date of such service), (ii) sent by Federal Express (or other overnight courier service) (in which event notice shall be deemed to have been given on the day of receipt), or (iii) mailed to the party to whom notice is to be given, by first class United States mail, registered or certified, return receipt requested, postage prepaid, and properly addressed as follows (in which case such notice shall be deemed to have been duly given on the second day following the date of such mailing):

To LICENSOR:

Christina Petersen
GMO Renewable Resources
69 South Pleasant St
Amherst, MA 01002

To LICENSEE:

110 Turnpike Rd , Ste 203
Westboro, MA 01581

17. **Miscellaneous:** This Assignment shall be binding upon and shall inure to the benefit of the parties and their respective successors and assigns (to the extent assignment is permitted hereunder) and may be executed in multiple counterparts, each of which when so executed shall be deemed an original, but all such counterparts shall constitute one and the same instrument This Assignment contains the entire agreement and understanding of the parties with respect to the subject matter hereof and supersedes all prior and contemporaneous agreements with respect thereto This Assignment shall be governed by and construed in accordance with the laws of the State of Maine, without regard to the principles thereof relating to conflicts of laws

IN WITNESS WHEREOF, LICENSOR and LICENSEE have caused this instrument to be executed effective as of the Effective Date

LICENSOR

By:
Its: Operating Member

LICENSEE

TRANSCANADA PIPELINE USA INC

By:
Its: GARRY LAMB
Vice-President, Risk Management

By:
Its: Donald J. DeGrandis
Assistant Secretary

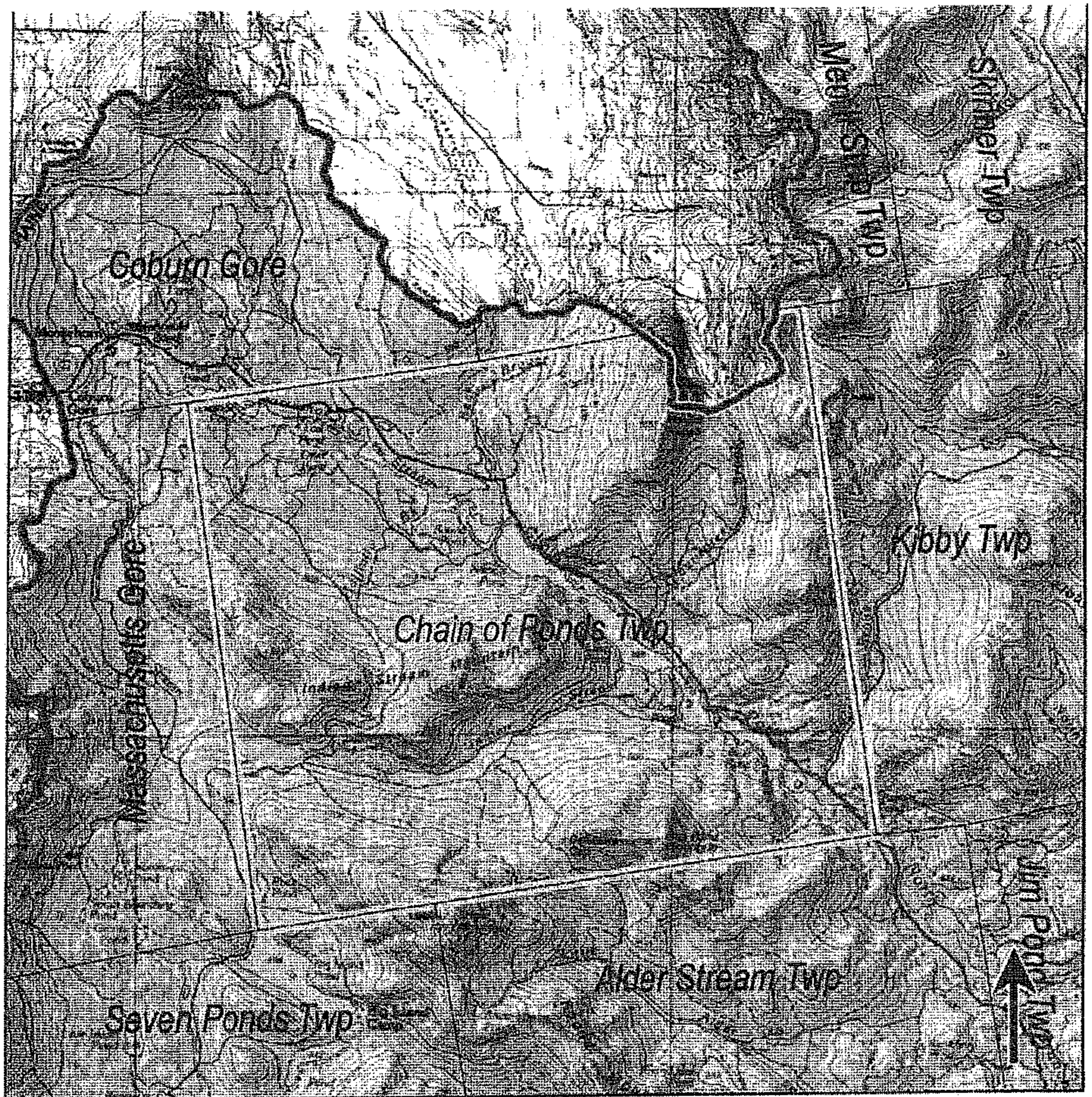
LEGAL	
CONTENT	

Exhibit A

Licensor's Land

See attached map:

Kennebec West Forest LLC
Chain of Ponds Township



0 1 2
Miles

~~Kibby~~ Wind Power Project

Chain of Ponds Township

Base: 100k USGS Topographic Map

TRC 249 Western Ave
Augusta, ME 04330

Exhibit B

The Premises

All that certain lot or parcel of land now owned by Licensor located in Chain of Ponds Township, Franklin County, Maine and lying northerly and easterly of State Route 27.

Exhibit C

Evaluation Equipment and Scope of Work

Installation of one or more meteorological towers, new trails to facilitate the construction and operations of these towers, and structures as required to undertake avian radar studies, all as permitted by the LURC.

SPECIAL USE LICENSE AGREEMENT

PLUM CREEK MAINE TIMBERLANDS, L.L.C., a Delaware limited liability company, having offices at One Concourse Parkway Suite 755 Atlanta, Georgia 30328, hereinafter referred to as "PLUM CREEK", in consideration of the covenants and conditions contained herein, hereby authorizes **TRANSCANADA MAINE WIND DEVELOPMENT INC.**, a Delaware corporation, with an address of 110 Turnpike Rd., Ste. 103, Westboro, MA 01581, hereinafter referred to as "LICENSEE", to enter upon certain property owned by PLUM CREEK in the State of Maine, County of Franklin, (the "Real Property") and described on Exhibit "A" attached hereto and made a part hereof by reference.

This Special Use License Agreement (the "License") is made upon the following terms and conditions:

1. The undersigned LICENSEE voluntarily assumes all risk of injury (including death) or property damage arising out of, or based upon, the undersigned LICENSEE's use of the Real Property.

2. The rights herein granted are not exclusive and LICENSEE's use is confined to the area necessary to serve its immediate need and does not include the right to control the use of the Real Property to the exclusion of the public or to others who may have been granted rights by PLUM CREEK. In addition, the rights granted herein are only for the Real Property and access to the Real Property over roads owned by PLUM CREEK. It shall be LICENSEE's responsibility to secure access rights across lands owned by other parties.

3. LICENSEE acknowledges and agrees that this License is given and received for the sole purpose of authorizing LICENSEE and its contractors to use existing roads and trails on the Real Property and to construct and use a new trail on the Real Property as described below for the purposes of access and egress, by its and its contractors' personnel, vehicles and equipment, to adjoining third party property. LICENSEE shall not utilize the Real Property for any other purpose. The new trail shall (i) be approximately 4000 feet long, (ii) not exceed twelve feet in width, (iii) be located along the route shown on the attached Exhibit "A"; and (iv) not disturb more than two (2) acres. LICENSEE shall pay PLUM CREEK [redacted] for the new trail upon the execution of this Agreement, and an additional [redacted] upon completion of the trail if the total disturbed area for the new trail exceeds 1.0 acre.

4. This License is made without warranty of title and subject to any and all easements, leases, rights of way, oil and gas leases and/or servitudes, of whatever kind or nature, which may be presently of record or visible by a physical inspection of the Real Property. PLUM CREEK HEREBY EXPRESSLY DISCLAIMS AND NEGATES ANY REPRESENTATIONS OR WARRANTIES OF ANY KIND, EXPRESS OR IMPLIED, RELATING TO THE CONDITION, MERCHANTABILITY OR FITNESS FOR A

PARTICULAR PURPOSE OF THE REAL PROPERTY, it being the intention of PLUM CREEK and LICENSEE that rights to enter upon the Real Property is granted subject to the "as is", or present condition of the Real Property and that LICENSEE has made or caused to be made such an inspection as it deems appropriate.

5. LICENSEE shall obtain all licenses and permits with respect its operations at the Real Property and pay all fees and charges in connection therewith or otherwise which are or may be lawfully demanded or required by any governmental authority. LICENSEE, at its sole expense, shall comply with all laws, orders and regulations of any governmental authorities and with any directive of any public officer which shall impose any violation, order or duty upon PLUM CREEK or LICENSEE with respect to the Real Property or the use or occupancy thereof by LICENSEE including, without limitation, any governmental law or statute, rule, regulation, ordinance, code, or policy now or hereafter in effect relating to endangered species, game management, the environment, health, safety or any substances, materials or wastes regulated by any governmental authority or deemed or defined as a "hazardous substance", "hazardous material", "toxic substance", "toxic pollutant", "contaminant", "pollutant", "solid waste", "hazardous waste" or words of similar import under applicable laws and regulations of the jurisdiction in which the Real Property is located and the political subdivisions thereof having jurisdiction over the Real Property.

6. As additional consideration for the use of the Real Property, the undersigned LICENSEE shall indemnify and save PLUM CREEK and Plum Creek Timber Company, Inc., together with its subsidiaries and affiliates (the "Plum Creek Companies") harmless, and, at LICENSEE's expense, shall defend PLUM CREEK and the Plum Creek Companies from and against any and all claims, suits, losses, damages, or expenses, whether caused or contributed to by the negligence of PLUM CREEK and the Plum Creek Companies, or their respective agents, or employees, or otherwise, on account of injuries to or death of any and all persons whomsoever, including LICENSEE, employees of LICENSEE, and of PLUM CREEK and the Plum Creek Companies, and any and all damage to property to whomsoever belonging, including property owned by, rented to, or in the care, custody, or control of the parties hereto, arising or growing out of, or in any manner connected with the exercise of the rights granted under this License or caused or occasioned, in whole or in part by reason of or arising during the presence of the person or of the property of LICENSEE, its employees, agents or invitees, upon or in proximity to the property of PLUM CREEK and the Plum Creek Companies, provided that LICENSEE shall not be liable to PLUM CREEK and the Plum Creek companies for any consequential, indirect, special or punitive damages (whether in contract, tort or otherwise). Notwithstanding the foregoing, nothing herein contained is to be construed as an indemnification against the sole combined negligence of PLUM CREEK or the Plum Creek Companies, and their respective officers, employees, or agents. Further, LICENSEE will defend at its own expense, in the name and on behalf of PLUM CREEK and the Plum Creek Companies all claims or suits for injuries to or death of persons or damage to property arising or growing out of the exercise of the rights granted under this License for which PLUM CREEK or the Plum Creek Companies are liable or are alleged to be liable.

7. In further consideration of the authorization herein granted the undersigned LICENSEE does hereby release and discharge PLUM CREEK, and the Plum Creek Companies and their respective officers, agents, employees, successors and assigns, from any and all manner of claims, demands, damages, causes of action or suits that the undersigned might now have or that might subsequently accrue against them, created by, arising out of, or based upon the undersigned's use of the above described Real Property owned by PLUM CREEK.

8. a. LICENSEE shall obtain and maintain during the term of this License, at LICENSEE's expense, policies of liability and Workers' Compensation Insurance, issued in a form and by an insurance company acceptable to PLUM CREEK with a Best's Key Rating Guide of B+ or better. Minimum coverage requirements shall be as follows:

(1) Commercial General Liability Insurance to include minimum limits of $500,000 combined single limit Bodily Injury and Property Damage each occurrence. Extensions of coverage to include Contractual Liability, Broad Form Property Damage, Completed Operations, Cross Liability and Pollution arising out of heat, smoke or fumes from a Hostile Fire.

(2) Comprehensive Automobile Liability Insurance covering owned, non-owned, hired and other vehicles, with a combined single limit of $500,000 for bodily injury, death and property damage per occurrence.

(3) Employer's Liability Insurance, for employee bodily injuries and death, with a minimum limit of $100,000 per occurrence.

(4) Workers' Compensation Insurance, with statutory limits as required by the laws and regulations applicable to the employees of LICENSEE.

b. The policies specified in Paragraphs (a) (1), (2) and (3) above shall include an endorsement which shall name PLUM CREEK and Plum Creek Timber Company, Inc. and its subsidiaries and/or affiliates, and their respective officers, directors and employees as additional insureds on for the duration of the License term. The additional insured endorsement must be ISO CG20 10 11 85 or other form with like wording. LICENSEE must maintain completed operations coverage with additional insured extension for a period of two (2) years after completion and acceptance by PLUM CREEK of the work performed, should the Additional Insured Endorsement not be ISO CG20 10 11 85 or like form.

c. The policies specified in (a) (1), (2) (3) and (4) above shall include an endorsement which shall provide that PLUM CREEK shall be given a 30-day written notice at One Concourse Parkway Suite 755 Atlanta, Georgia 30328, prior to cancellation, coverage modification or other material change in the policy. No such cancellation, modification or change shall affect LICENSEE's obligation to maintain the insurance coverages required by this License.

d. Prior to commencement of activities, LICENSEE shall furnish to PLUM CREEK a Certificate of Insurance dated and signed by a stated, authorized agent for the insuring company or companies, in a form acceptable to PLUM CREEK and containing a representation that coverage of the types listed in Paragraph a. above is provided with the required liability limits. PLUM CREEK reserves the right to require a certified copy of the policy(ies) or to examine the actual policy(ies). Said certificate(s) of insurance shall be issued to PLUM CREEK at the address above.

e. LICENSEE shall be responsible for payment of any and all deductibles from insured claims under its policies. The coverage afforded under any insurance policy obtained by LICENSEE pursuant to this paragraph shall be primary coverage regardless of whether or not PLUM CREEK has similar coverage. LICENSEE shall not self-insure any of the insurance coverages required by this License without the prior written consent of PLUM CREEK. The minimum limits of coverage required by this License may be satisfied by a combination of primary and excess or umbrella insurance policies. The maintenance of this insurance shall not in any way operate to limit the liability of LICENSEE to PLUM CREEK under this License.

9. LICENSEE shall not cut or remove any live timber from the Real Property except as may be reasonably required for the purposes set out in Section 3 above without permission from PLUM CREEK, and will take all proper and necessary steps to protect the Real Property from unauthorized occupancy, trespass, and damage by fire, and assume all responsibility for the spread of fire in or from the Real Property and from all damage to the personal property on the Real Property, and to the timber thereon and on adjoining lands, in each case, arising from its use of the Real Property.

10. LICENSEE agrees to remove all property and facilities owned by LICENSEE within the time prescribed in a notice of termination and to leave the Real Property in a safe, clean and sanitary condition, free of litter and debris, satisfactory to PLUM CREEK, acting reasonably. In the event of failure to do so, PLUM CREEK may remove such property and facilities and restore the Real Property at the expanse of LICENSEE, or may appropriate such property and facilities to its own use without compensation. As between the parties, LICENSEE shall bear the full risk of, and shall make good, such damages or losses and shall deliver the Real Property back to PLUM CREEK at the termination of this License in accordance with this License.

11. This License shall be effective for a period of 36 consecutive months beginning on March 1, 2009, provided that after the first 18 months PLUM CREEK may terminate this Special Use License with or without cause by providing 60 days written notice to LICENSEE.

12. This License or any interest therein is not assignable by LICENSEE without written consent from PLUM CREEK, which may be withheld at PLUM CREEK's sole discretion provided that the LICENSEE may assign this License to an affiliate without such consent.

13. There are no oral promises made by PLUM CREEK in connection with or in consideration of the execution of this License. Any waiver by PLUM CREEK of any provision hereof must be in writing.

14. This License shall be governed by and construed in accordance with the laws of the State of Maine.

IN WITNESS WHEREOF, the undersigned parities have executed this License on this the _____ day of March, 2009.

LICENSEE:

TRANSCANADA MAINE WIND DEVELOPMENT INC.

By: ______________________
Authorized Signature

Name: William Taylor
Print Name

Title: Vice President

By: ______________________
Authorized Signature

Name: Michael Nachey
Print Name

Title: Vice President

____

PLUM CREEK:

PLUM CREEK MAINE TIMBERLANDS, L.L.C.

By: ______________________
Authorized Signature

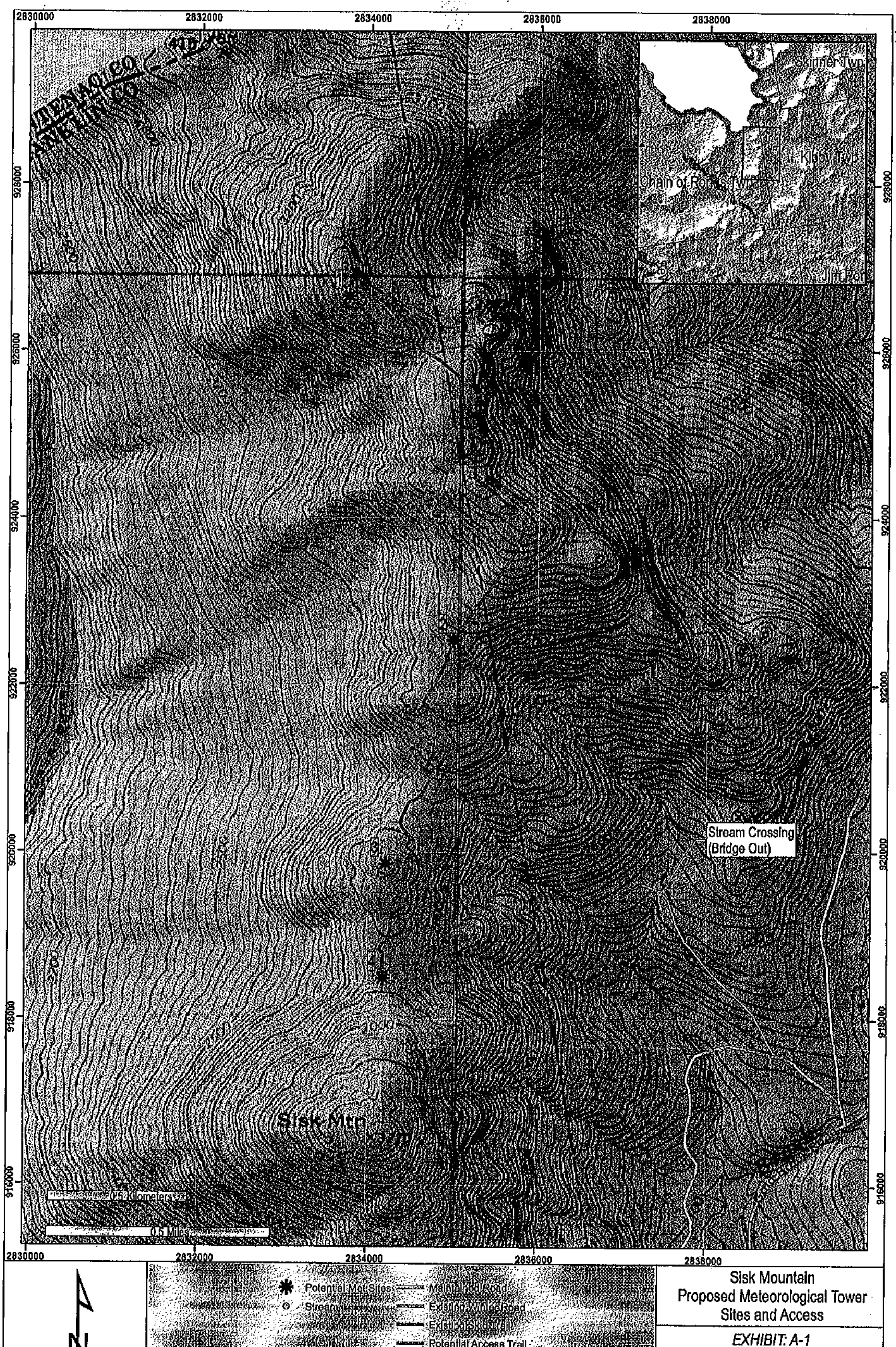
Name: ______________________
Print Name

Title:

LEGAL	
CONTENT	

EXHIBIT "A"

MAP OF PROPOSED TRAIL



Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

Sisk Mountain
Proposed Meteorological Tower Sites and Access

EXHIBIT: A-1

249 Western Ave
Augusta, ME 04330

TRC

Created:
2/6/2009

EXHIBIT C:

SITE PHOTOGRAPHS

LIST OF PHOTOGRAPHS

Photo 1: Looking west at Sisk Mountain from a clearcut on Kibby Range.
June, 2008

Photo 2: Example of an existing access trail such as may be found on Sisk Mountain. Photo looking down slope, toward the west, from the northeastern slope of Kibby Range.
June, 2005

Photo 3: Clearcut in vicinity of proposed project; looking west from clearcut toward southern peak of Sisk Mountain.
7/14/2005

Photo 4: Typical woods on ridges above 3,200 feet in elevation in the project vicinity.
8/9/2005

Photo 5: Typical woods such those at proposed met tower sites. Photo taken at approximate elevation 3,140 feet.
8/9/2005

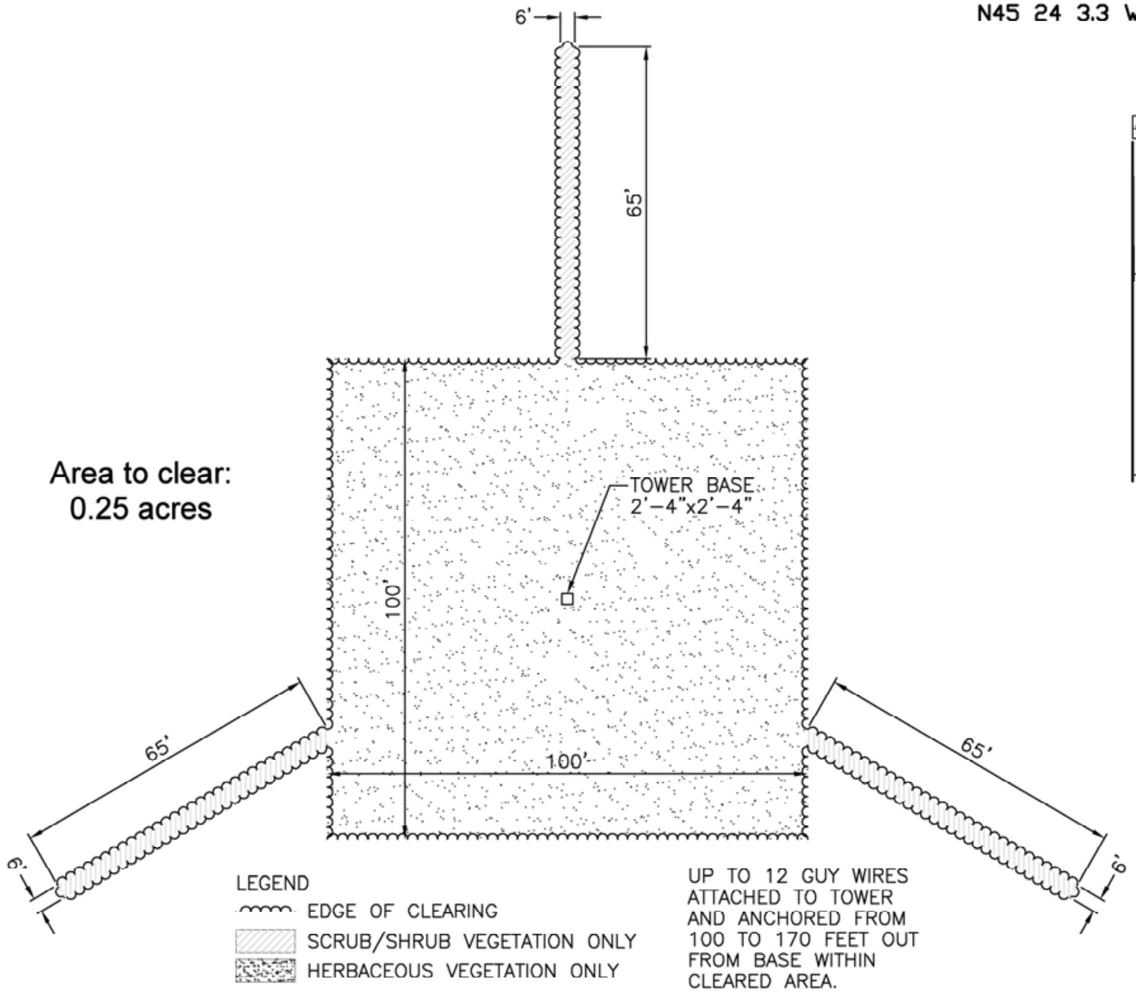
Photo 6: Stream crossing on existing winter road where culvert will be replaced for proposed access.
03/10/09

EXHIBIT D:

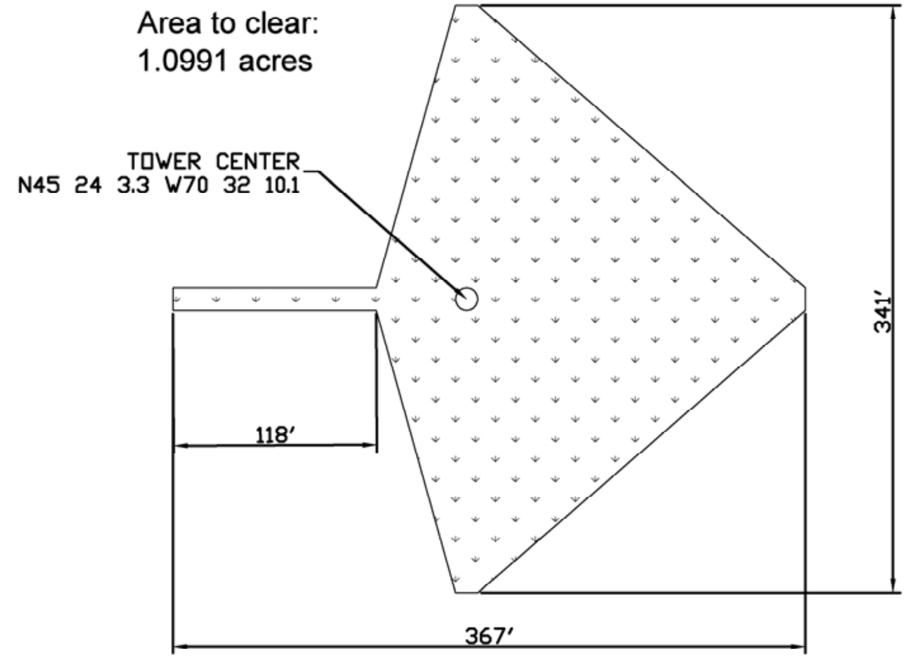
SITE PLAN

EXHIBIT D: SITE PLAN

LIST OF FIGURES



Typical installation site plan for 60m lattice met tower



Typical installation site plan for NRG 60m tubular met tower

TRC

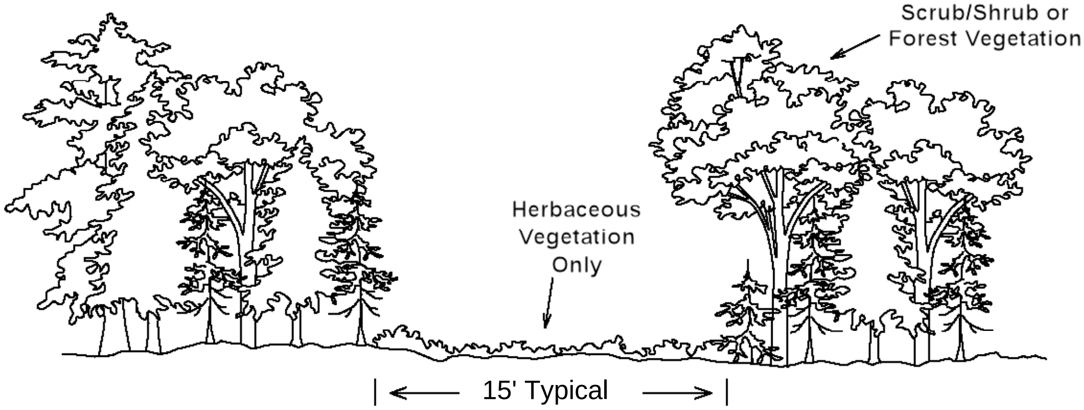
Typical Met Tower Installation Site Plans

-Not to Scale-

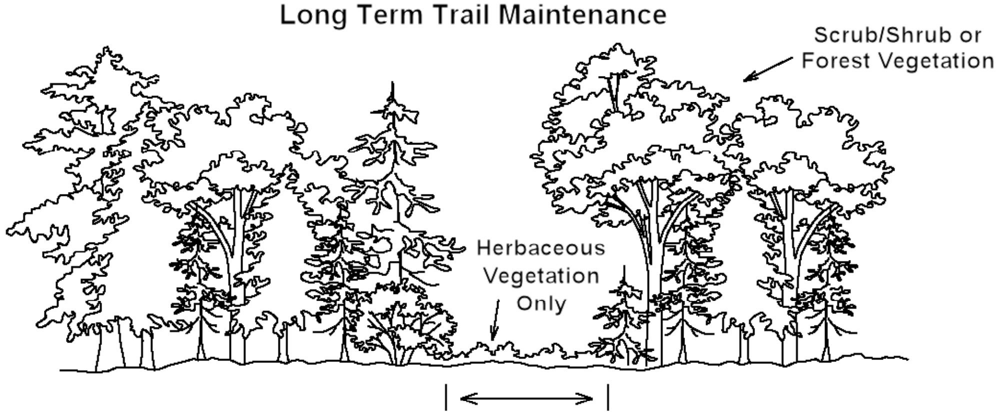
Sisk Wind Power Project

Exhibit D-1

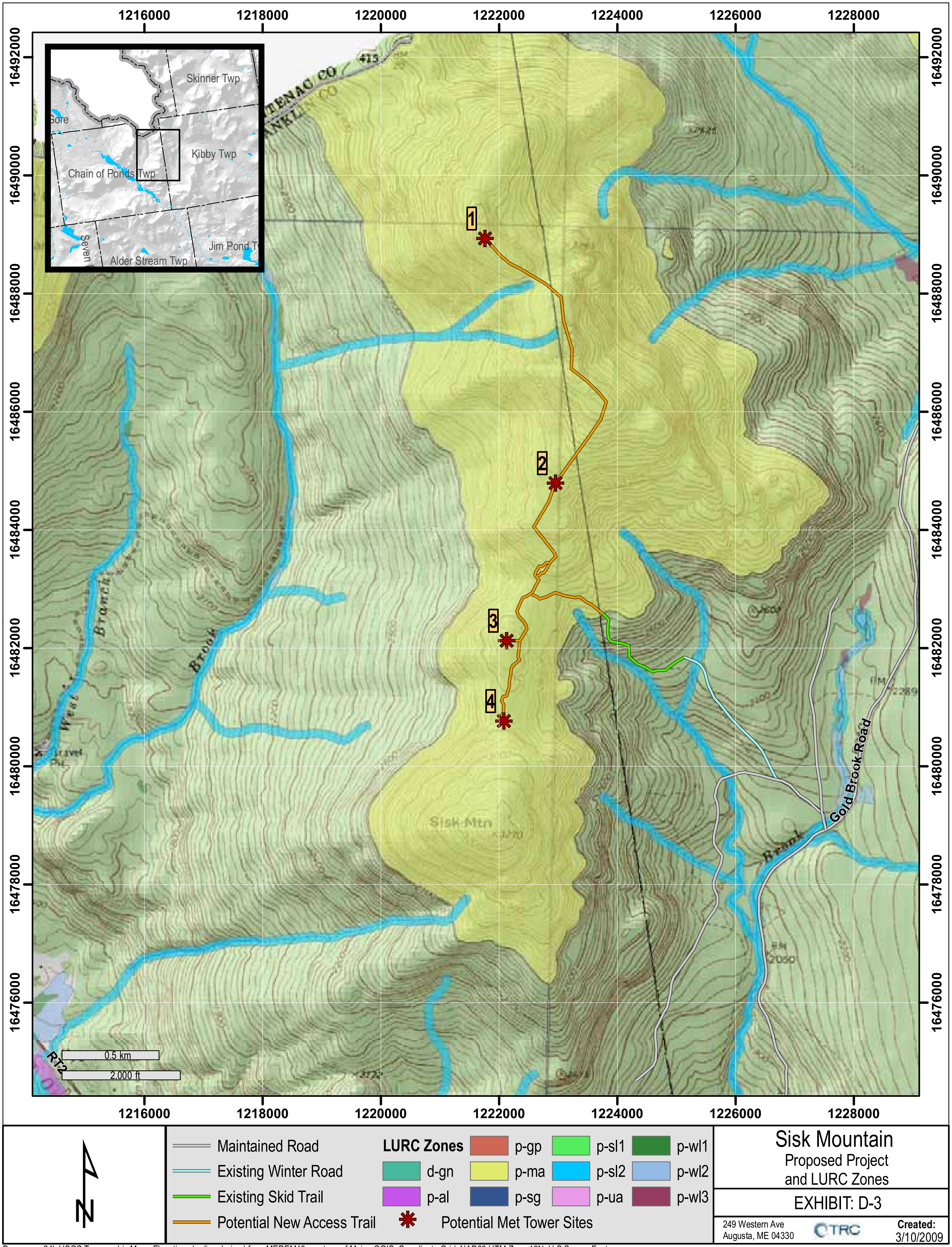
Construction Access Trail



Long Term Trail Maintenance



TRC	Typical Access Trail Profiles -Not to Scale-	**Sisk Wind Power Project** Exhibit D-2



Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, U.S Survey Feet

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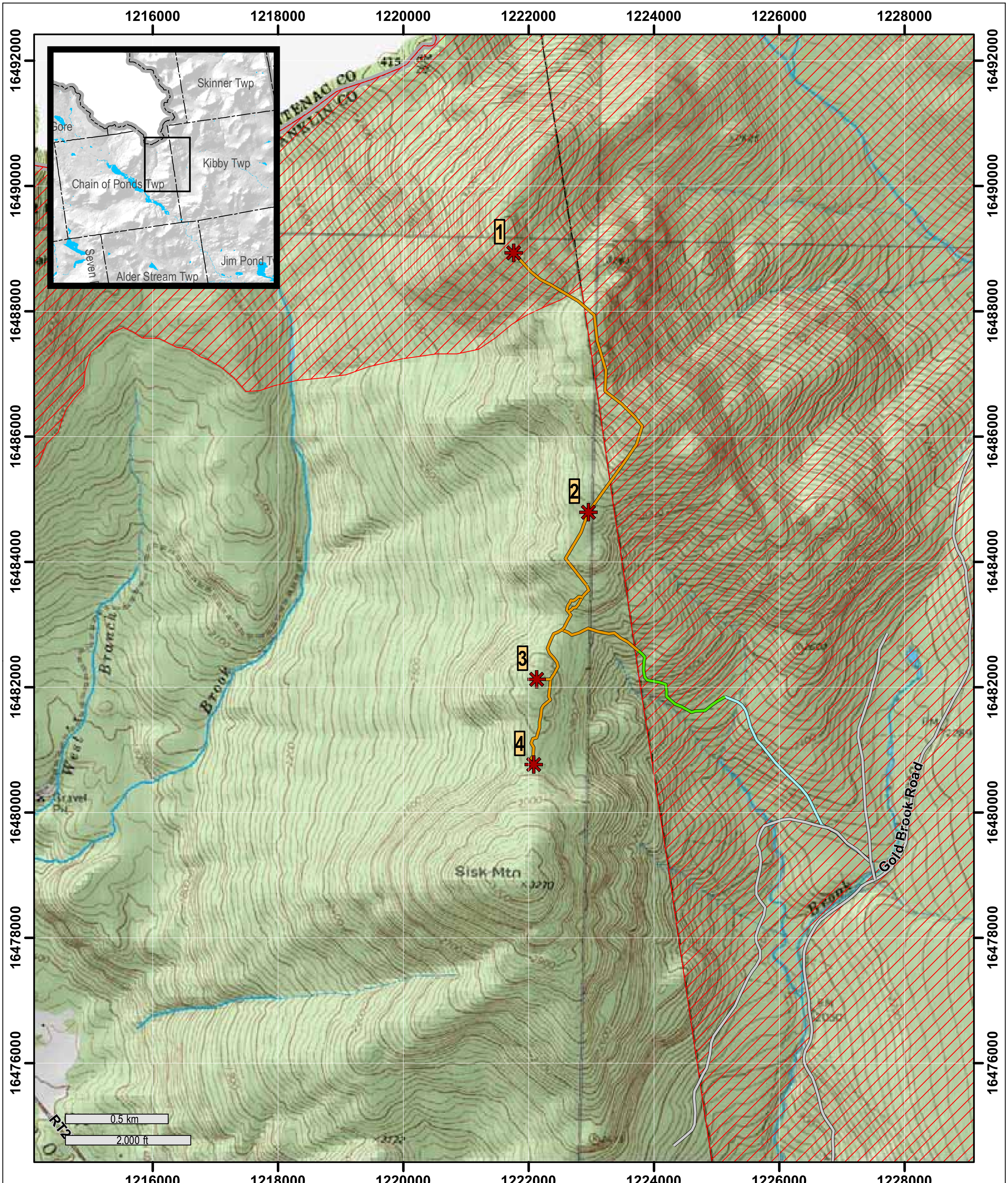

N

Maintained Road

Existing Winter Road

Existing Skid Trail

Potential New Access Trail

Expedited Windpower Project Permitting Area

Potential Met Tower Sites

Sisk Mountain

Expedited Windpower Project Permitting Area

EXHIBIT: D-4

249 Western Ave
Augusta, ME 04330

TRC

Created: 3/10/2009

Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, U.S Survey Feet

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EXHIBIT H:

EROSION & SEDIMENTATION CONTROL PLAN

TABLE OF CONTENTS

LIST OF FIGURES

1.0 Introduction

TransCanada Maine Wind Development (TransCanada) has prepared this Erosion and Sedimentation Control Plan (E&S Plan) to be a stand-alone document containing all erosion and sedimentation control requirements related to the installation and maintenance of the meteorological towers (met towers) and associated equipment. This plan also addresses E&S control during geotechnical investigations. Since the potential for soil disturbance or exposure of soil would be most significant during the clearing of the met tower sites and access trails and from transporting the equipment and materials needed for installation of the towers and geotechnical work, this E&S Plan is based on the Maine Forest Service's *Best Management Practices for Forestry: Protecting Maine's Water Quality* (MFS BMP), dated 2004. The MFS BMPs were supplemented, where appropriate for excavation and other activities related to installation of the met towers with practices from the Land Use Regulatory Commission (LURC) Chapter 10 Subchapter III, Land Use Standards (LURC Chapter 10), and the Maine Department of Environmental Protection's *Maine Erosion and Sediment Control BMPs*, dated March 2003.

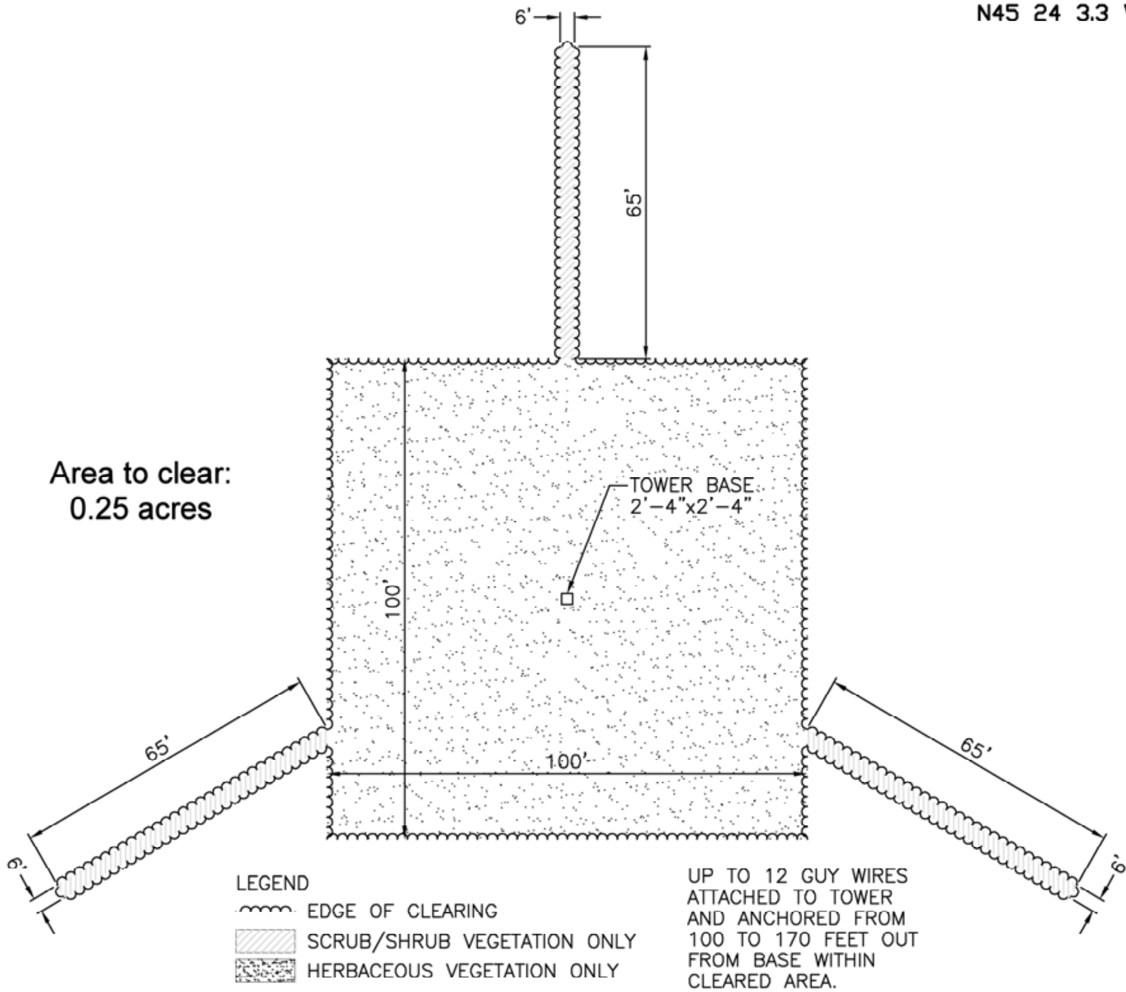
Trail clearing and met tower installation activities can largely avoid and minimize soil disturbance by being performed during the winter in snow and frozen ground conditions. This E&S Plan is written, however, to prescribe practices which would be needed during any season, but especially for spring, summer, and fall seasons when soil disturbance is unavoidable.

2.0 Scope of Work

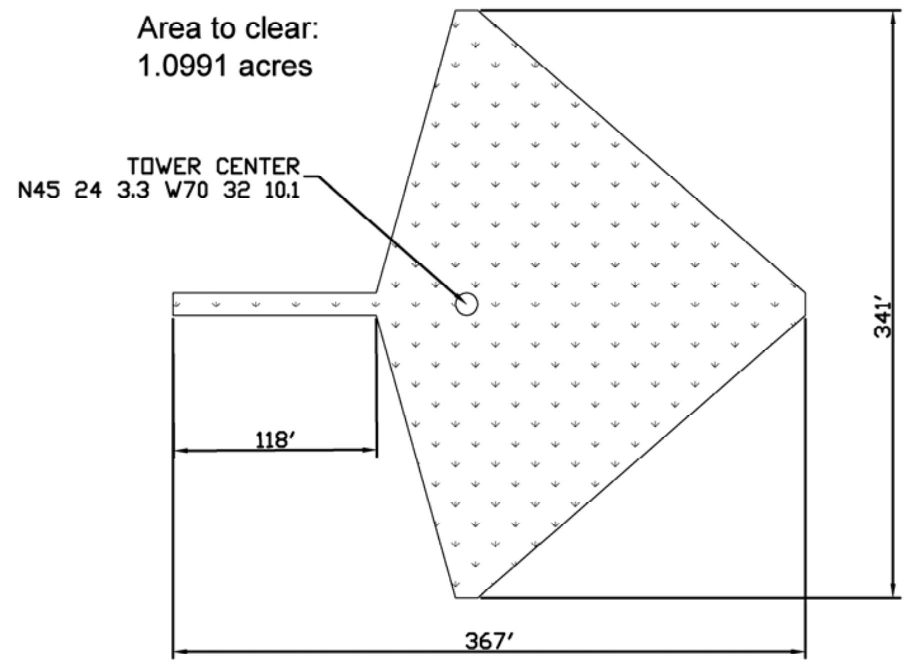
TransCanada proposes to install four meteorological towers (met towers) and associated access along the ridge of Sisk Mountain, one of the Boundary Mountains in Chain of Ponds and Kibby Townships, Maine. Sisk Mountain is located immediately to the west of the Kibby Range, which is part of the recently permitted Kibby Wind Power Project, and shares the same access from Route 27, Gold Brook Road. The trail established for met tower access will also be used for geotechnical studies and other environmental studies related to project assessment.

One of the proposed met towers will be a lattice structure; three will be tubular structures. In order to provide sufficient area for safe and efficient movement of personnel, materials, and equipment during installation of these structures, some clearing will be necessary.

The lattice met tower location will require an approximately 100- by 100-foot area, centered at the base of the tower, that has been cleared of all woody vegetation (all trees and shrubs) so that only very low ground cover vegetation remains. Stumps, ground cover, and forest duff layers will not be removed. In order to be able to attach and position guy wires and raise the met towers without significant entanglement of guy wires in vegetation, trees will be cut at ground level and other woody vegetation will be cut down to approximately 3 feet tall along three 3-foot wide by 65-foot long corridors that extend out from the cleared area. This two-tiered approach to clearing and trimming of vegetation will minimize to the maximum extent practical the removal of vegetation at the met tower location. The clearing required for the tubular towers will be similar to clearing for the lattice tower, with stumps, ground cover and forest duff layers left intact. The footprint of the cleared area, however, is larger and asymmetrical. Site plans for tubular towers are designed to accommodate full assembly of the tower on the ground; the tower is then erected while fully rigged. Typical site plans for each of these met tower styles are provided in Figure 1.



Typical installation site plan for 60m lattice met tower



Typical installation site plan for NRG 60m tubular met tower

Typical Met Tower Installation Site Plans

-Not to Scale-

Sisk Wind Power Project

Figure H-1

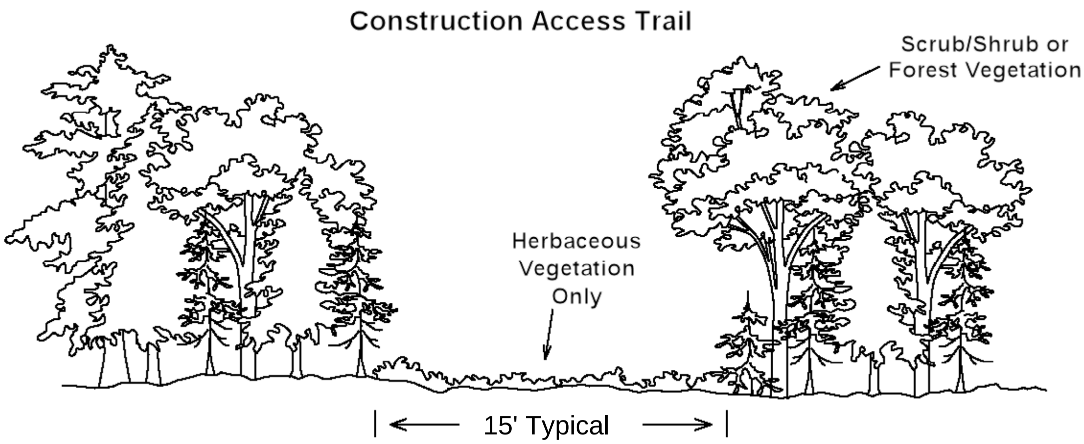
Guy-wire anchors will be installed into bedrock where possible. Soil disturbance will consist of excavation approximately 25 square feet at each anchor location in order to uncover bedrock. Where bed rock anchors are not feasible, excavation of a hole approximately 1-foot wide by 5-feet long by 4-feet deep will be necessary to install plate or dead-man anchors. These holes will be backfilled and compacted to original grade.

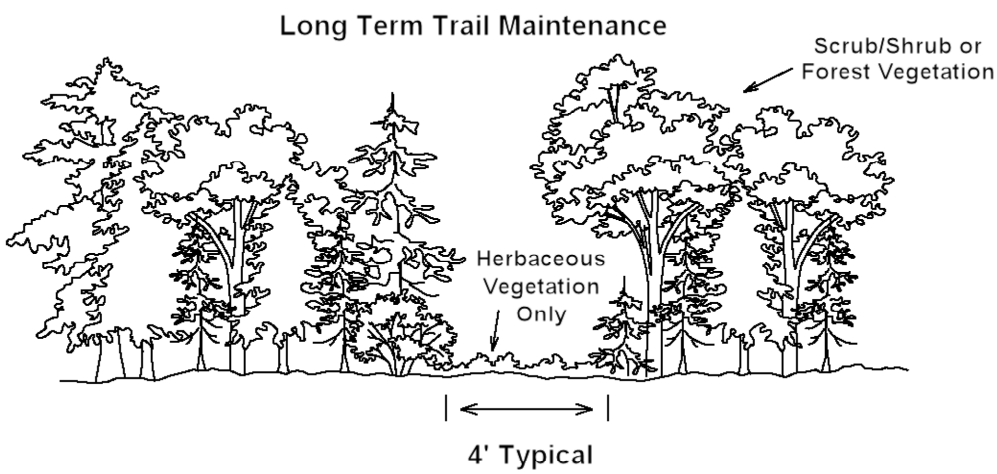
An existing road and trail will be used to access the met tower sites to the maximum extent possible. Logging roads and recent skidder trails are present up to approximately 2,700 feet in elevation. Where trails do not currently exist or trail conditions are inadequate, new or improved trails will be established by removing only trees and shrubs. Stumps, ground cover, and forest duff layers will not be removed unless necessary to allow for safe travel of equipment. The locations of new trails were selected by reviewing topographic maps and field reconnaissance, with the goal to minimize the length of the trail. Avoidance of very steep slopes, wetlands, and stream crossings was also considered and incorporated as much as practical. See Figure 2 for examples of trail profiles.

Clearing, along the trail and at the four planned met tower locations will be performed using a harvester (or other logging equipment). Met tower sections and equipment for construction will be transported to the site by low a ground pressure track vehicle or forwarder. A small backhoe/excavator will also be needed to install ground anchors. Geotechnical equipment will include a track mounted drill rig and all terrain vehicles. As a result, access trails will need to be 15 feet wide to allow passage of mobile equipment and minimize disruption of soils or remaining vegetation.

Little, if any, additional clearing will be required for geotechnical survey. Geotechnical work will take place within the cleared trail and at cleared met tower sites; the only additional trees that may be cut for the purpose of geotechnichal surveys are those that directly impede survey work.

Trail use by large equipment, such as the skidder or track-vehicle, will be temporary. These vehicles will be used primarily for clearing, delivering met tower construction materials, and geotechnical work. Once these tasks are complete, the only expected project-related use of the trails will be by met tower construction crews (ATV/snowmobile and foot access), maintenance crews (sporadic ATV/snowmobile and foot access, as needed), and environmental study personnel (mostly on foot). Due to the use of large equipment only for a short timeframe during clearing, met tower installation, and geotechnical work, and no expected use for operation and maintenance, erosion is not expected to be a significant issue for the proposed project. Similar activities will be associated with met tower removal, and the measures outlined in this E&S Plan will be employed.





TRC	Typical Access Trail Profiles -Not to Scale-	**Sisk Wind Power Project** Figure H-2

3.0 Soils and Slopes

Soils in the project area are primarily formed in glacial till. Most areas have a relatively thick organic soil layer with a thick well-developed mineral layer. Slopes in the vicinity of trails are 5 to 30 percent, and the met tower sites are in areas where slopes are close to 0 percent. No areas of bare mineral soils or exposed bedrock were observed at these sites or along the proposed access trails. Some of the trail and tower sites likely have shallow bedrock soils, however it appears that most of the met tower sites are on a rocky glacial till and are not on exposed bedrock.

4.0 Vegetation

Natural communities potentially found in the vicinity of the access route, from lowest to highest elevations are:

- Spruce - Northern Hardwoods Forest, up to 2,700 feet in elevation;
- Spruce - Fir - Wood Sorrel - Feathermoss Forest, up to 3,500 feet; and
- Fir-Heartleaved Birch Subalpine Forest, 3,200 feet and higher.

Most of this area has been previously harvested up to the highest elevations (approx. 3,400 feet) on the ridge, similar to Kibby Mountain and Kibby Range, so these natural communities are not clearly present as defined by Maine Natural Areas Program (MNAP). There is no Fir-Heartleaved Birch Subalpine Forest mapped by MNAP on Sisk mountain. Based on field surveys, in the area of the met tower sites the typical community is composed of species that are representative of both Spruce-Fir-Wood Sorrel-Feathermoss and Fir-Heartleaved Birch Subalpine Forest. Dominant tree species are balsam fir, red spruce, and heart-leaved birch. Shrubs present include balsam fir, mountain ash and hobblebush. Herbaceous species commonly found are goldthread, Canada dogwood, raspberry, blue-bead lily, mountain woodfern, intermediate woodfern, and northern wood sorrel.

5.0 Met Tower Construction Sequence

The met tower construction sequence generally consists of the following steps.

1. Planning and flagging the location of access trails and met tower sites.

2. Clearing existing trails to adequate width, or clearing new trails. Installation of erosion and sedimentation control practices, as required, along access trails. At this stage, a temporary stream crossing spanning the channel within the existing access road will be installed. Inspection for disturbed soils will start at this time, and will be performed throughout construction.

3. Clearing met tower sites, as required to meet necessary size for met tower installation. Erosion and sedimentation control inspections of access trails and met tower sites ongoing.

4. Transporting construction materials to met tower sites. Erosion and sedimentation control inspections of access trails and met tower sites ongoing.

5. Installing met towers, including excavation for anchors, where necessary. Installation of erosion and sedimentation control practices including mulch and silt fence as anchor sites are backfilled. Erosion and sedimentation control inspections of access trails and met tower sites ongoing.

6. Removal of temporary equipment crossings and final stabilization of disturbed soils.

7. Erosion and sedimentation control inspections of access trails and met tower sites periodically until stabilized.

Note that clearing or other construction activities will be suspended during periods of heavy or prolonged rainfall, or when surface runoff is apparent in areas affected by construction.

Geotechnical survey work will start once trails are cleared and conditions are suitable for equipment travel on the trails.

6.0 Erosion Control Practices for Trails

6.1 Planning

The first step in preventing erosion is planning trail layout. To the extent practical, new trails will avoid all wetlands, streams, and slopes steeper than 15 percent. Soil disturbance will be avoided to the maximum extent possible, and few stumps, and little forest duff, or top-soil will be removed from new access trail areas. In areas where slopes are steeper than 15 percent, access trails will be curved and sited on or close to contour, when doing so is safe and practical. These areas will be climbed by use of switchbacks or by traversing to areas of gentler slope. In some cases this may require stump removal and excavation to level trail surfaces. Where traveling up slopes that are steeper than 15 percent is necessary, soils on these slopes will be padded with brush (from clearing) to reduce compaction and prevent soil disturbance (per recommendation of the State Soil Scientist at the Maine Department of Agriculture, and the MFS BMP manual "Trails and Harvesting" subsection). Other areas where soils can be protected with brush are those areas that are wet, soft, and may be prone to rutting (though not wetland). Wetland areas will be protected by use of mats (see Section 6.2). Another consideration when planning a new access trail will be to utilize natural terrain to divert runoff water from the trail area.

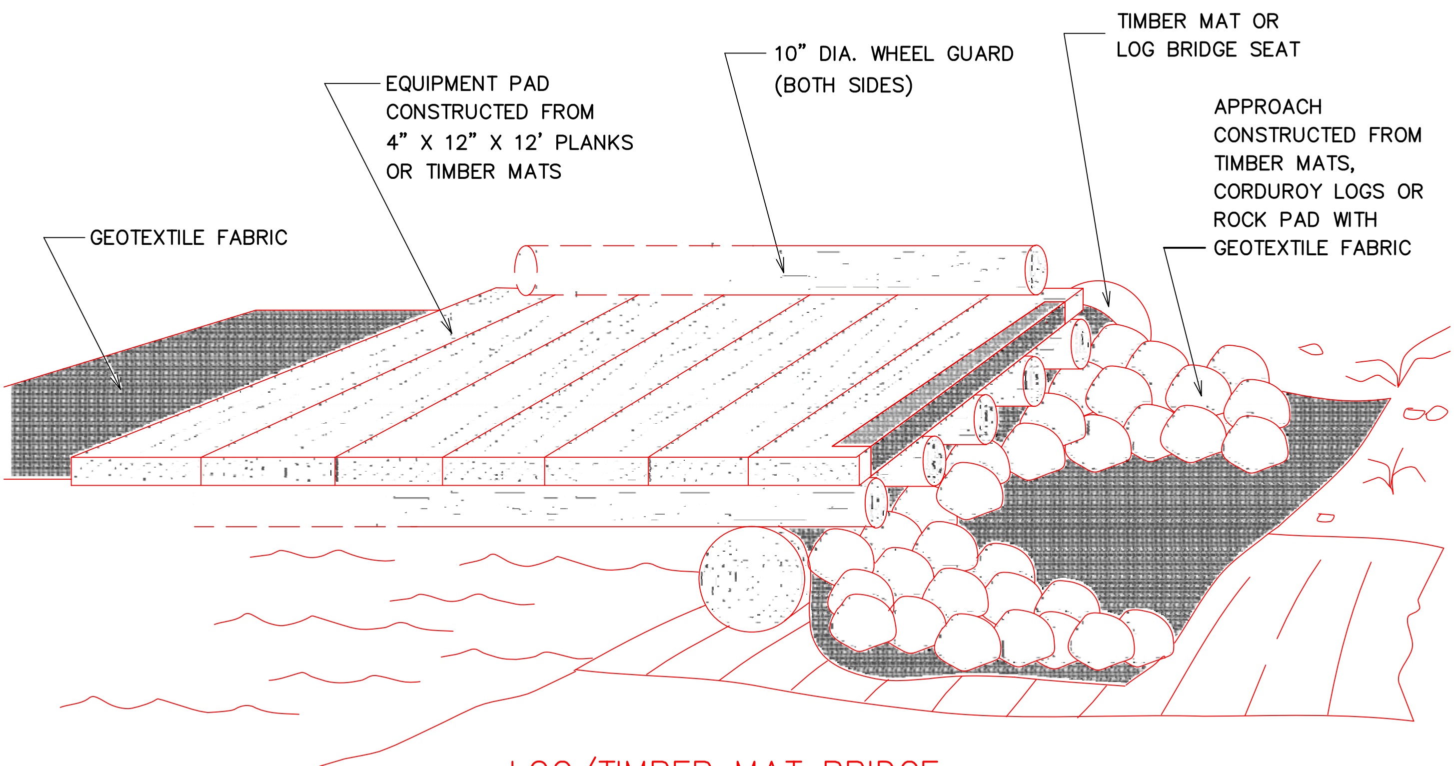
For existing trails, the same concepts apply: trails or portions of trails that cross wetlands, streams, or steep slopes will be avoided when practical. In some instances, it may not be possible to avoid these areas. In the case of streams or wetlands, a crossing may be installed to prevent erosion and ruts from developing or deepening. These are described below. On steep slopes, brush will be placed in access trails to help prevent rutting and to protect topsoil.

6.2 Stream or Wetland Crossings

The stream crossing required to access met tower locations will be temporary, to the extent possible. A timber mat crossing will be installed to span the stream, which crosses an existing access road. A culvert crossing was installed when this road was in active use for timber harvesting activities; the crossing and culvert were removed once the road was no longer needed. Likewise, the proposed crossing will be removed once the met towers and equipment are up and running correctly, and the crossing is no longer required for equipment access. See Figure 3 for a typical timber mat bridge stream crossing detail. Geotexile fabric will be installed under the mats to minimize debris falling into the water. The stream crossings will be inspected weekly to ensure that the structure complies with LURC standards and BMP specifications. This shall include cleaning soil from the travel surface of the bridge or mat, as needed.

While the mats are in place, the crossing site will be evaluated for installation of a permanent road crossing. If it is determined that the site is appropriate for a permanent crossing, an engineering assessment of the site will be performed to determine the suitable type of crossing (e.g., culvert, arch, bridge, etc.). Permit applications, as required, will be filed with LURC and the Army Corps of Engineers at that time.

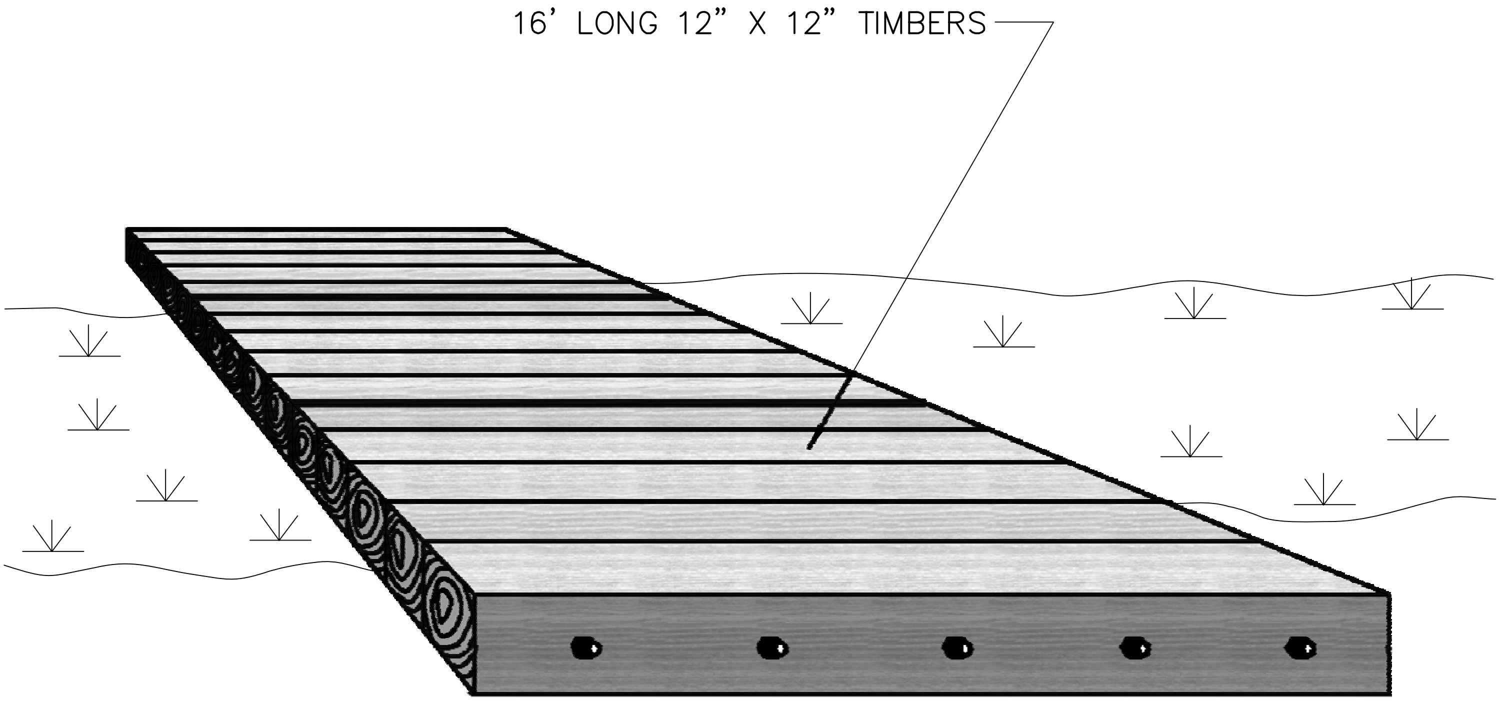
SPAN	DIAMETER (80,000 lb. load)	DIAMETER (40,000 lb. load)
8 ft.	16 in.	12 in
12 ft.	18 in.	14 in.
16 ft.	20 in.	16 in.



LOG/TIMBER MAT BRIDGE
(TEMPORARY)

NOTES:
1. Span small crossings with mats.
2. Add support culverts to stream if the stream is too wide to span with one mat length. (Ensure fish passage requirements)
3. Add geotextile fabric under equipment pad to prevent soil from entering stream.
4. Install wheel guards to ensure that soil does not spill over into stream.
5. Approaches to equipment pad may be timber mats, corduroy logs, or a rock pad over geotextile fabric.
6. Additional pads can be placed side by side if extra width is required.
7. Equipment pad typically contructed of hardwood; must accommodate the largest equipment utilized.

TRC	Typical Installation Log/Timber Mat Bridge -Not to Scale-	**Sisk Wind Power Project** Figure H-3



PREFABRICATED
TIMBER MAT WETLAND CROSSING
(TEMPORARY LIGHT DUTY)

NOTE: TIMBER MATS TO BE PLACED WITH THE LONGEST DIMENSION OF THE MAT PERPENDICULAR TO THE DIRECTION OF TRAVEL.

TRC	Typical Installation Timber Mat Wetland Crossing -Not to Scale-	**Sisk Wind Power Project** Figure H-4

6.3 Silt Fence

Silt fence generally will not be used along access trails, since soil disturbance will be kept to a minimum. However, the case may arise where a sediment barrier will be necessary to prevent excess or unreasonable movement of soils. In these cases, silt fence is the preferred sediment barrier due to portability, ease of installation and effectiveness. Silt fence is installed by first excavating a trench approximately 4 inches wide by 6 inches deep. Trench spoils are shoveled onto the uphill side of the trench. The silt fence is then staked into this trench, with the attached fabric on the upslope side of the stakes. The trench is then backfilled with the trench spoils. See Figure 5 for a typical silt fence installation detail.

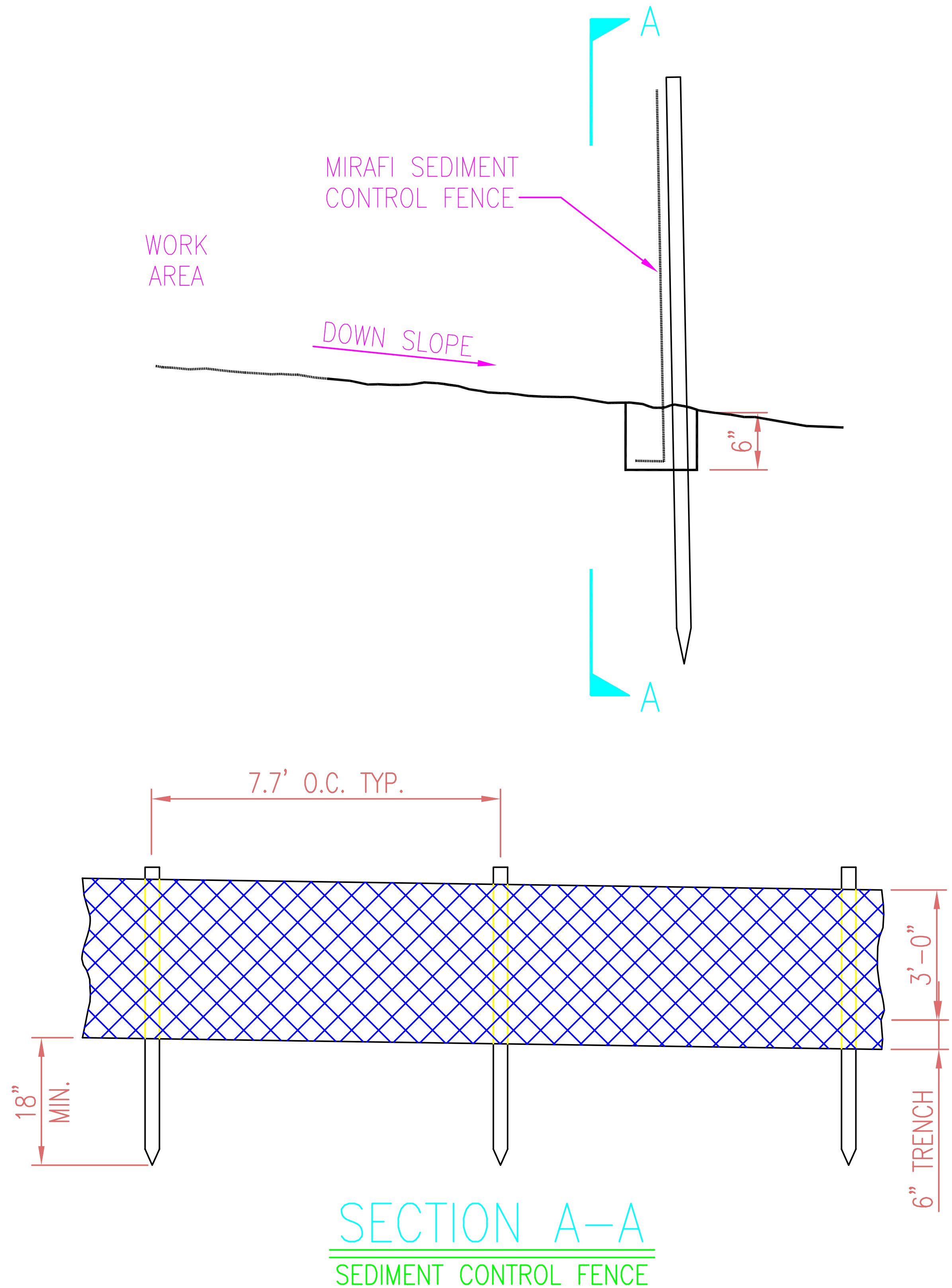
Silt fences will be inspected weekly at a minimum, immediately after a significant rainfall event, and daily during periods of prolonged rainfall. They will be repaired immediately if there are any signs of damage, erosion, or sedimentation downslope of them. Accumulated sediment deposits will be removed after each significant storm event, or when deposits reach approximately one-half the height of the fabric. Any sediment removed shall be spread in an upland area, seeded, and mulched. When the site has stabilized or erosion is no longer a problem at the site (vegetation has been established), the silt fence will be removed and any remaining bare soils will be seeded and mulched.

6.4 Mulch

In general, mulch will only be used in areas where bare soil has been exposed by large equipment (e.g., anchor locations) or to temporarily or permanently stabilize water bars (if used) or other disturbed areas. Permanent stabilization with mulch may be accompanied by seeding. Mulch will consist of hay or straw, or erosion control blankets (also known as matting). Hay mulch will not be used in wetlands.

In most areas of disturbed soils with slopes less than 15 percent, hay or straw mulch will be applied at a rate of about 2 bales per 1000 square feet, or enough to cover at least 90 percent of the ground surface. Where slopes with soil are steep (15 percent or greater) or within 100 feet of a stream or wetland, mulch will be anchored with netting, or erosion control blankets may be used to ensure bare soils are stabilized. Figure 6 provides a typical installation detail for mulch anchoring, and Figure 7 illustrates the correct installation of erosion control blankets.

Areas that have been mulched or matted (e.g., covered with erosion control blankets) will be inspected weekly and after significant rainstorms to check for rill erosion or slope failure until vegetation is firmly established. If less than 90 percent of the soil surface is covered by mulch, additional mulch will be applied immediately. If washouts occur, the eroded areas will be repaired and re-seeded, and mulch or matting reapplied.

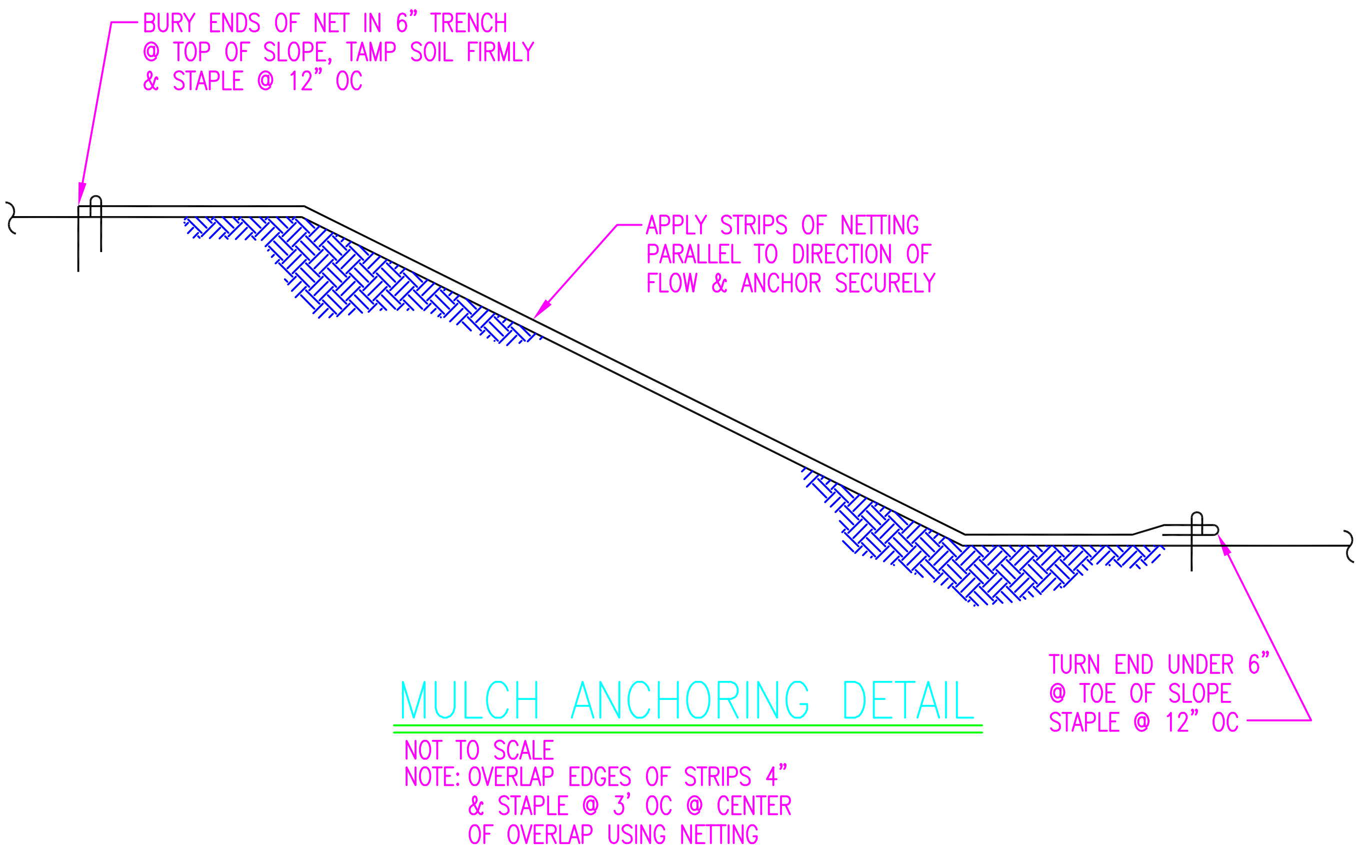


TRC

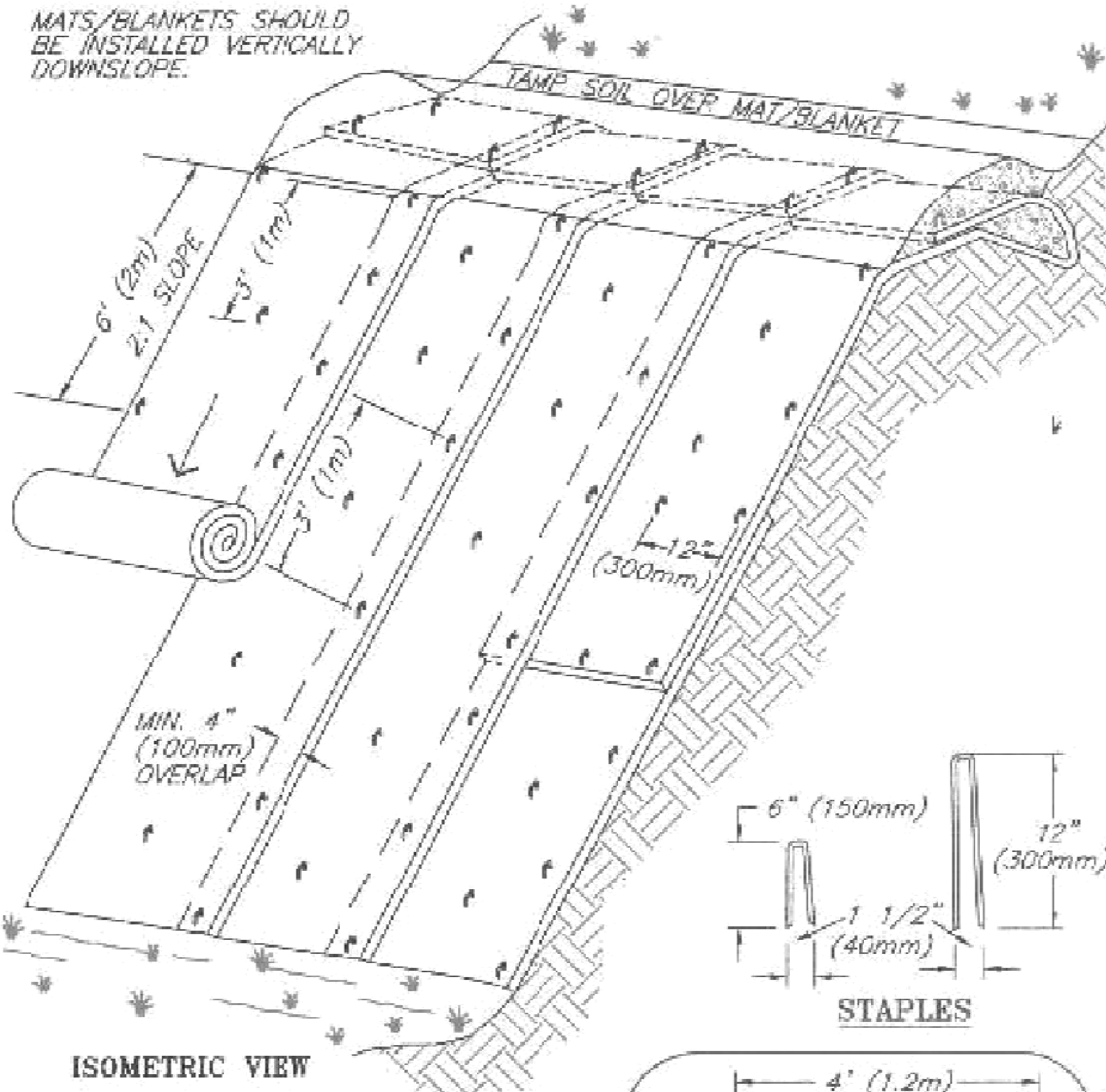
Typical Installation
Silt Fence
-Not to Scale-

Sisk Wind Power Project

Figure H-5

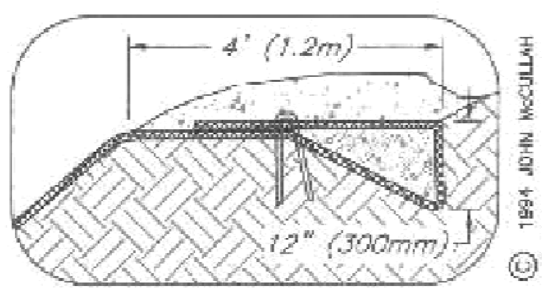


TRC	Typical Installation Mulch Anchoring Detail -Not to Scale-	**Sisk Wind Power Project** Figure H-6



ISOMETRIC VIEW

STAPLES



TOP OF SLOPE ANCHOR DETAIL

TYPICAL SLOPE SOIL STABLIZATION

NOT TO SCALE

NOTES:

1. SLOPE SURFACE SHALL BE FREE OF ROCKS, CLODS, STICKS AND GRASS. MATS/BLANKETS SHALL HAVE GOOD SOIL CONTACT.
2. APPLY PERMANENT SEEDING BEFORE PLACING BLANKETS.
3. LAY BLANKETS LOOSELY AND STAKE OR STAPLE TO MAINTAIN DIRECT CONTACT WITH THE SOIL. DO NOT STRETCH.

TRC	Typical Installation Slope Stabilization Using Erosion Control Blankets -Not to Scale-	**Sisk Mountain Wind Power Project**
		Figure H-7

6.6 Water Diversions

It is not anticipated that water diversions will be used, except as a last resort, since installation of water bars requires soil disturbance. If running water is causing erosion of the access trail, water diversions (such as a water bar) will be installed to help move the water away from the access trail. Care must be taken to ensure that water is being diverted into vegetated uplands which are effective filter areas, and not into wetlands or streams. In general, water bars should be at least six to twelve inches deep, six to twelve inches wide, and installed at a 30-degree angle to the trail. Seed and mulch, as appropriate, may be applied to stabilize bare soils associated with construction of water bars. Water bars should extend far enough beyond the trail edge to ensure water does not flow back onto the trail. Brush (e.g., generated from the clearing operations) should be placed at the outlets of water bars in order to slow the flow of water and retain sediment. See Figure 8 for a typical water bar detail and recommended spacing table. Water bars will be inspected and repaired, as needed, following each day of use to be sure they are not being rutted or eroded. Once construction activities are completed, the water bars should be repaired and reshaped as needed to maintain their effectiveness without the need for regular maintenance.

6.7 Seeding

In general, seeding will be completed only if topsoil is significantly disturbed or eroded. It is expected that topsoil will be present where soils are disturbed and will provide an adequate seed base of native plants. Where seeding is conducted, the goal is to establish a vigorous vegetative cover over at least 85 percent of the disturbed area. The following seed mixes will be used in disturbed upland areas, as recommended by the Franklin County Soil and Water Conservation District:

For areas below 2300’ in elevation, the following “conservation mix” is recommended:

Creeping red fescue:	18%
Flat pea:	52%
Tall fescue:	26%
Redtop:	4%

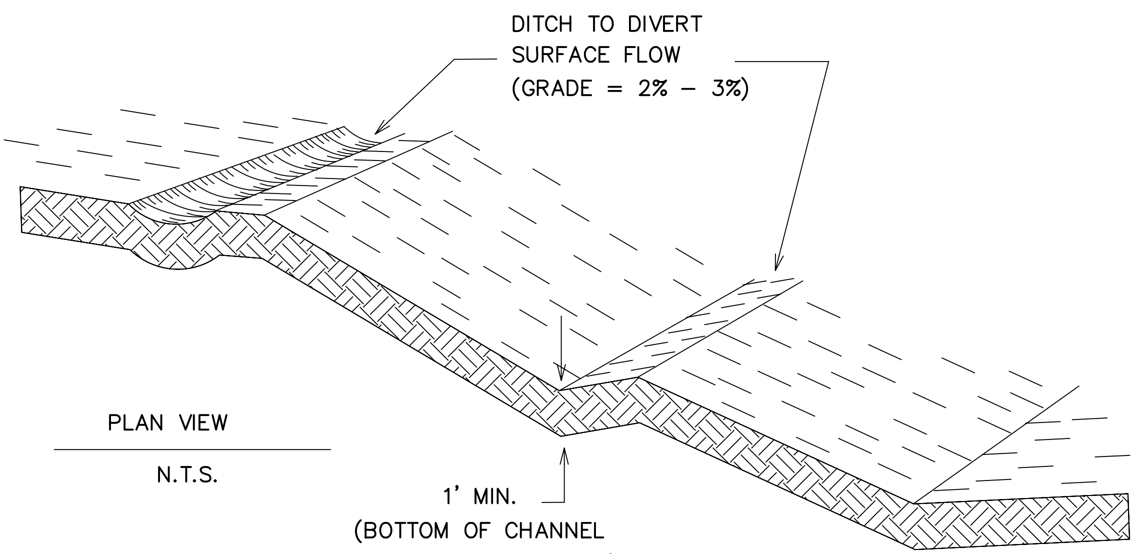
For areas above 2300’ in elevation, the following “high elevation cover” seed mixture is recommended:

Hard fescue	25%
Chewings fescue	17%
Creeping red fescue	17%
Creeping bentgrass	17%
Redtop	7%
Birdsfoot trefoil	14%

White clover (ladino type) 3%

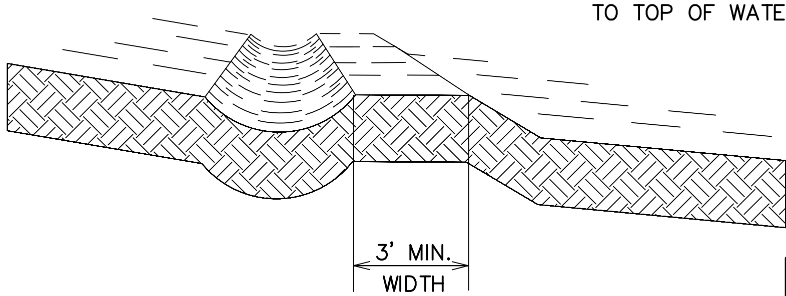
Disturbed wetland areas will be seeded with annual winter rye at 1 lb per 1,000 square feet, as necessary. Fertilizer or lime will not be used in wetlands and, in general, will not be used unless determined to be necessary.

TYPICAL WATER BAR CONSTRUCTION



PLAN VIEW

N.T.S.



CROSS SECTION

N.T.S.

RECOMMENDED SPACING BETWEEN WATER BARS	
SLOPE (PERCENT)	SPACING (FEET)
0–2	500–300
3–5	250–180
6–10	167–140
11–15	136–127
16–20	125–120
21+	100

NOTES:

1. All trees, brush, stumps, rocks, and other obstructions shall be removed and disposed of to prevent interference with the proper functioning of the diversion.

2. Fills shall be compacted as needed to prevent unequal settlement or failure.

3. All graded areas shall be stabilized with temporary or permanent seeding.

4. Diversion channel should be lined with erosion control fabric as soil conditions require.

5. The outlet of the water bar must be to a well vegetated area or be stabilized by installing a stone check dam, haybale/silt fence dissipating device or synthetic geomat, depending on the amount of channelized flow expected. If used, the geomat will consist of a geotextile fabric 8 feet wide and 10 feet long. The end of the fabric at the right–of–way must be toed into the ground.

TRC	Typical Installation Water Bar -Not to Scale-	**Sisk Wind Power Project** Figure H-8

7.0 Erosion Control Practices for Tower Clearings

Within the clearings created for the met towers or access/geotechnical survey trails, the greatest potential for significant, project-related soil erosion would occur in upland areas during initial clearing and during construction. Slopes at tower sites, which will generally have a larger area of disturbed soil than geotechnical sample locations, are generally level or less steep (typically less than 10 percent) than along access trails. Exposure of bare soil is anticipated only where excavation is required to install a ground or bedrock anchor; where geologic samples are being collected; along the trail where leveling is needed for equipment access; and in those areas that experience repeated use for travel by clearing, construction, or sampling equipment. In the limited excavated areas, topsoil will be stockpiled separately from subsoils, and the soils will be replaced in order, with topsoil being replaced last. This practice will help stabilize the disturbed soils and encourage the reestablishment of native plants from natural seed sources.

Erosion and sedimentation control measures in these areas will include: the use of only mulch at level excavated anchor sites; mulch and silt fence downslope of excavated anchor locations on slopes; and possibly some silt fence, mulching, and seeding in any site prone to erosion or at an unusually large area of disturbance. The details of the installation, inspection and maintenance of these erosion and sedimentation control measures will be as described for their use along access trails.

8.0 Winter Construction Considerations

In the event that installation of the met towers occurs during the fall or winter season (September 15 – May 15), mulching and seeding will be modified to ensure adequate stabilization.

- Mulching: From September 15 – May 15, if hay or straw mulch is used, it will be applied at a rate of about 4 bales per 1000 square feet. Hay or straw mulch will also be anchored when applied on slopes greater than 5 percent during this time of year. Anchoring is most efficiently accomplished by using netting. As an alternative, erosion control mats can be used in place of hay/straw mulch and netting. In sensitive areas, where slopes are 15 percent or greater or within 100 feet of a stream or wetland, a heavy grade mat will be used.

- Seeding: Between October 15 and April 15, seeding will be done at a rate of three times higher than the standard specified rate for permanent seeding (two times higher in wetlands) and then mulched.

9.0 Recommended Reference Materials

The following reference materials were used in preparing the E&S Plan and are recommended for additional guidance, as necessary.

LURC. 2004. LURC Chapter 10, Sub-chapter III, Land Use Standards, September 13, 2004. Available on-line at: http://www.state.me.us/doc/lurc/reference/ch10.html

Maine Department of Environmental Protection. 2003. Maine Erosion and Sedimentation Control BMP's. Available on-line at http://www.state.me.us/dep/blwq/docstand/escbmps/index.htm, and by calling MDEP at 1(800) 452-1942.

Maine Forest Service. 2004. Best Management Practices for Forestry: Protecting Maine's Water Quality. Available on-line at www.maineforestservice.org, and by calling the Maine Forest Service at 1(800) 367-0223 (in-state) or 1(207) 287-2791.

ATTACHMENT A:

PROJECT LOCATION & DESCRIPTION

TABLE OF CONTENTS

1.0 Introduction

TransCanada Maine Wind Development (TransCanada) is assessing the development of a 14 unit wind power generating facility in the Boundary Mountains of Western Maine known as the Sisk Wind Power Project. Sisk Mountain is located in the unorganized townships of Kibby and Chain of Ponds, in Franklin County, Maine. This application is for the proposed installation of four meteorological towers (met towers) on the ridge of Sisk Mountain and associated geotechnical investigations. The met towers will quantify wind resource characteristics in the project area and will assist in ecological data collection. The geotechnical investigations will include borings to determine surficial and underlying rock qualities found on the ridge.

The Sisk Wind Power Project is immediately adjacent to the recently permitted Kibby Wind Power Project. A portion of the proposed project area for the Sisk Wind Power Project (Kibby Township) occurs within the LURC Expedited Wind Power Project Permitting area (see Figure A-1); the remainder of the proposed project is immediately adjacent to this area.

TransCanada intends to conduct baseline studies in addition tothe existing information from the Kibby Wind Power Project licensing effort to determine the level of potential impact associated with the proposed project.

2.0 Location of Proposed Activity

The proposed activity is located in an unincorporated area of Franklin County, Maine. The general project area is located along the ridgeline of Sisk Mountain, as shown in Figure A-1. The property in Kibby Township is owned by Plum Creek, and the property in Chain of Ponds Township is owned by GMO. The surrounding area is currently actively managed for forest products. The Sisk Wind Power Project can take advantage of existing logging roads and skidder trails to access up to elevation 2,700 feet, and forestry activities can continue in a complementary fashion with the met towers in place.

Property tax map and lot numbers for Kibby (T1R6 W.B.K.P.) and Chain of Ponds (T2R6 W.B.K.P.) are as follows:

- Kibby – FR13, Plan 1, Lot 1.1, Lot 2
- Chain of Ponds – FR014, Plan 01, Lot 1

Recording information for the property is as follows:

- Kibby - Recorded November 5, 1998, Book 1798/Page 107 (Skylark)
  Recorded November 9, 1998, Book 1799/Page 170
- Chain of Ponds – Recorded December 30, 2004, Book 2551/Page 302 and Book 2552/Page 40

The following is a land division history for the parent parcels now owned by Kennebec West Forest, LLC ("KWF") in Chain of Ponds Township and Plum Creek Maine Timberlands, LLC ("PC") in Kibby Township:

KWF PARENT PARCEL – CHAIN OF PONDS TOWNSHIP

The parent parcel in Chain of Ponds Township was acquired by KWF from SP Forests LLC by deed dated December 30, 2004 and recorded in the Franklin County Registry of Deeds in Book 2551, Page 302. Prior to KWF's ownership, the parent parcel was conveyed as follows:

- 2004, December 1: Out-parcel conveyed to The Megantic Fish and Game Corporation by deed recorded in the Franklin County Registry of Deeds in Book 2539, Page 43. This lot is not counted for subdivision purposes as this was a transfer to an abutter.

- 1999, June 16: Entire parent parcel conveyed to SP Forests LLC by IP Timberlands Operating Company, LTD by deed recorded in the Franklin County Registry of Deeds in Book 1865, Page 98.

There were no conveyances of the parent parcel between March 11, 1989 and June 16, 1999 other than in connection with a corporate reorganization of IP Timberlands Operating Company, LTD. In connection with this corporate reorganization, the entire parent parcel was conveyed by IP Timberlands Operating Company, LTD to IP N-S Assets, LP after which the name of IP N-S Assets, LP was changed to IP Timberlands Operating Company, LTD.

There are eight leased lots located on the parent parcel. All of these leased lots have been in existence for more than 20 years (with inception dates ranging from 1973 to 1981). Three of these lots were conveyed to the leaseholders (following conveyance by KWF to its parent entity Black Bear Forest, Inc. and a conveyance by Black Bear Forest, Inc. to its subsidiary Black Bear Cub, Inc., an affiliate of KWF):

- Lot 970-102 (located on Caribou Pond) conveyed to Robert Witherly;
- Lot 970-66 (located on Lower Pond) conveyed to Donald E. Olen, Sr.;
- Lot 970-36 (located off Route 27) conveyed to Kenneth G. Jones; and
- Lot 970-17 (located on Route 27) conveyed to Robert G. Cushman.

The remaining leased lots continue to be owned by KWF and leased to the long-term tenants as follows:

- Lot 970-057 (located off Route 27) leased to James K. Brochu;
- Lot 970-072 (located on Gold Brook Road) leased to Michael Reeve;
- Lot 970-087 (located northerly and westerly of a small beaver pond) leased to Robert S. Smith; and
- Lot 970-101 (located on Route 27) leased to the State of Maine, Department of Transportation.

In light of the foregoing, there have been no unauthorized divisions within the past 20 years.

PC PARENT PARCEL – KIBBY TOWNSHIP

The parent parcel in Kibby Township was acquired by SDW Timber II, LLC (now known as Plum Creek Maine Timberlands, LLC) from S.D. Warran Company by deed dated November 5, 1998 and recorded in the Franklin County Registry of Deeds in Book 1799, page 170. Prior to SDW/ Timber II, LLC/PC's ownership, the parent parcel was conveyed as follows:

- 1986, July 24: Entire parent parcel conveyed to S.D Warren Company by Scott Paper Company by deed recorded in the Franklin County Registry of Deeds in Book 913, Page 6.

In light of the foregoing, there have been no unauthorized divisions within the past 20 years.

3.0 Description of Proposed Activity

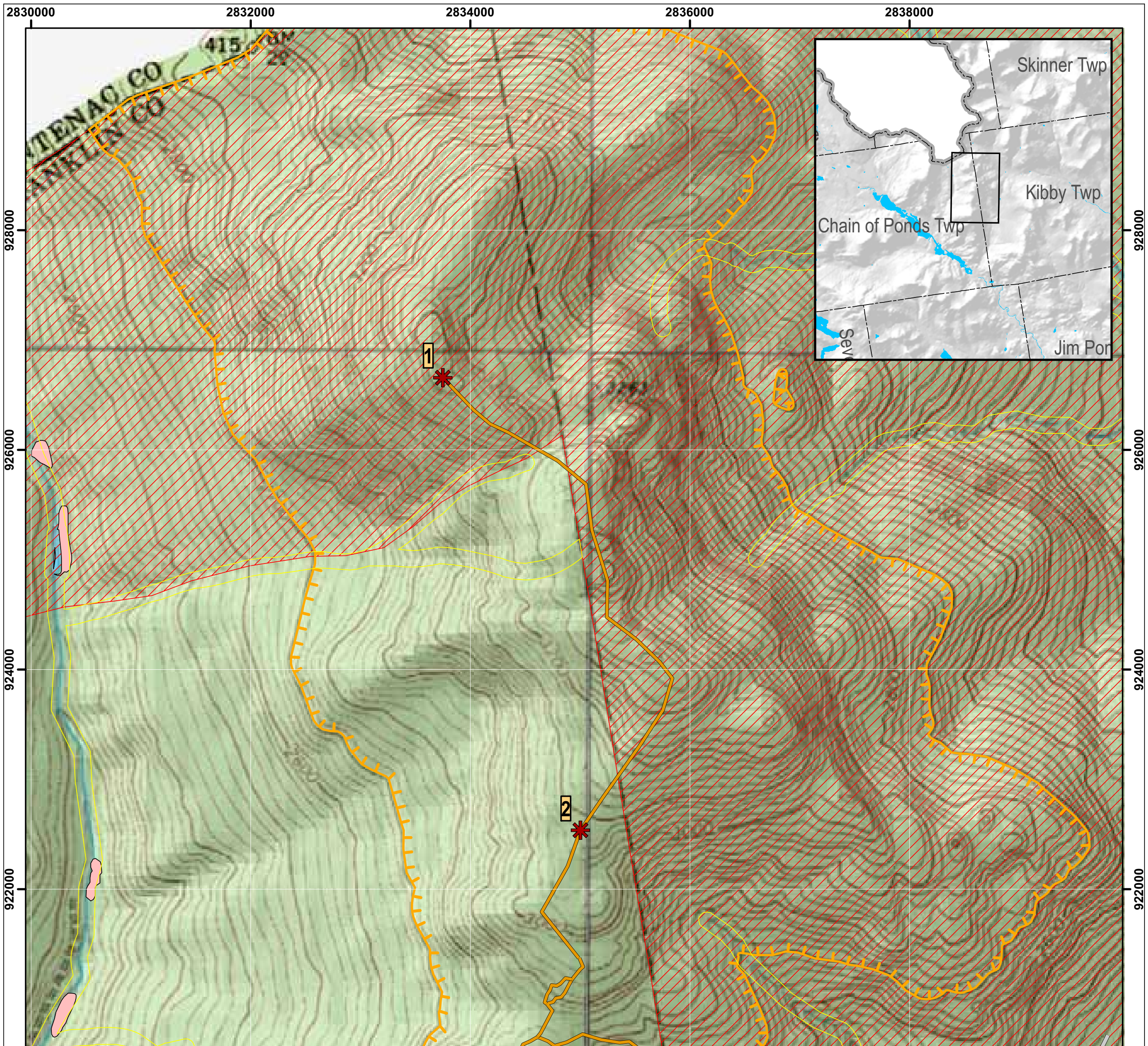
TransCanada is proposing to install four met towers along the ridge of Sisk Mountain. The met towers will be used during environmental studies (for example, bat surveys, where installation of monitoring devices at an elevated location provides the best possible data) as well as for collection of site-specific wind data. In order to install the proposed met towers, access to the ridge must be established. Proposed access trails have been located to allow transport of met towers to their proposed locations for installation via tracked equipment or all terrain vehicles (ATVs). After met towers have been installed, the access trails will be used to reach the met towers for maintenance on foot or via ATV or snowmobile. Access trails will also be used for ecological and geotechnical investigations. Proposed access trails utilize an existing logging road, winter road and skidder trail to the extent possible to minimize the need for clearing of new access trails.

Figure A-1 illustrates the four proposed met tower locations along the ridge of Sisk Mountain. Figure A-1 also illustrates proposed access trails to the proposed met tower locations. Details regarding access, characteristics of the proposed met towers, clearing requirements and other construction details are provided in Attachment B. Removal of the met towers following their use is also addressed in Attachment B.

4.0 Purpose of Proposed Activity

The installation of the met towers will support ongoing environmental studies and wind resource evaluation associated with the proposed Sisk Wind Power Project. The project will utilize the superior wind resource found in this vicinity to create clean, renewable power generation. TransCanada is committed to siting and designing the facilities to minimize environmental and community impact to the extent possible, and is planning a series of field studies to characterize current environmental conditions at the sites and augment studies that were undertaken for the recently permitted Kibby Wind Power Project.

TransCanada Energy Ltd. is a subsidiary of TransCanada Corporation, an established Canadian company, with a proven track record in developing large infrastructure projects, including numerous wind projects currently ongoing in Canada and the recently permitted Kibby Wind Power Project in Maine. An important hallmark of its development process is to establish and maintain strong, open and responsive relationships with the communities within which they will operate facilities and with the regulatory agencies tasked with project oversight. This application represents the first regulatory filing associated with the Sisk Wind Power Project, for data collection purposes.



N

Potential Met Tower Sites
Stream Crossing
Maintained Road
Existing Winter Road
Existing Skid Trail
Potential New Access Trail
Expedited Windpower Project Permitting Area
LURC P-WL Zone
LURC P-SL Zone
LURC P-MA Zone

Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

Sisk Mountain
Expedited Windpower Project
Permitting Area

FIGURE: A-1

249 Western Ave
Augusta, ME 04330

TRC

Created:
3/10/2009

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ATTACHMENT B:

DETAILS OF PROPOSED WORK

TABLE OF CONTENTS

FIGURES

TABLES

1.0 Met Tower Description

There are four potential met tower locations proposed for Sisk Mountain. These proposed locations are illustrated on Figure B-1.

The met towers proposed for installation on Sisk Mountain are 197 feet (approximately 60 meters) tall. One of the met towers will be a lattice structure and three will be tubular structures. The lattice structure will consist of rectangular sections that are approximately 10-feet long by 16-inches square; the tubular structures will consist of tubular steel sections that are approximately 9 feet long.

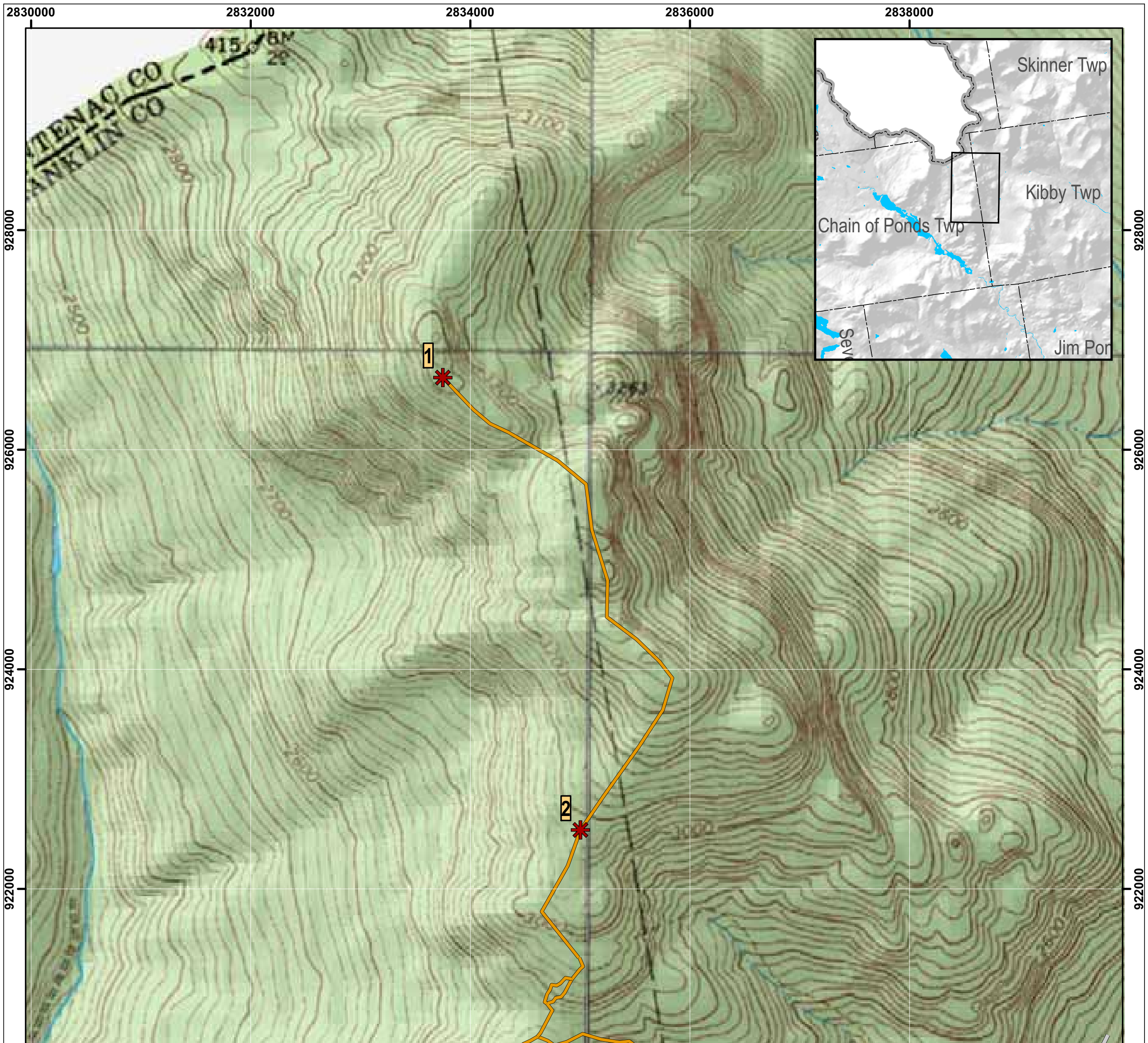
Each type of tower is assembled on site, but is erected utilizing different techniques. Lattice towers are raised, section by section, by climbers working from the installed base. This is possible because the lattice tower can be climbed by construction crews. The tubular tower is assembled on the ground and is raised with a gin pole and winch. The lattice tower base is anchored to bedrock, while the tubular towers will stand on a 30- by 30-inch square steel base plate set on the ground. Each tower, whether lattice or tubular, will be held in place by up to twelve steel-cable guy wires that will be anchored into the ground or bedrock. The guy wires will be attached at multiple levels up the met towers and will be anchored from approximately 50 to 150 feet out from the base of the met towers (depending upon site-specific conditions).

These met towers were selected for several reasons. First, exposure of the wind sensors at 60 meters above ground is required to accurately determine the wind characteristics that will:

- best define the overall suitability of the site for wind power generation;
- provide data for final determination of the physical size, generating capacity, number and location of the turbines to be proposed; and
- avoid interference with the characteristics of the regional wind pattern from local topography and vegetation.

Second, the selected met towers are easy to transport due to their modular construction, and they are easy to install because they do not require foundations or heavy machinery other than a backhoe or excavator. The lattice towers are also climbable, which facilitates sensor maintenance and repair; the ability to climb the met towers also eliminates the need for a crane during installation. Furthermore, these met towers have proven to be able to withstand the high winds and potential ice accumulation expected in terrain such as is found in the Boundary Mountains. Lastly, while the met towers are strong enough for the equipment and exposure required, their small cross-sectional area minimizes visual impact. No ground-based enclosure is required; all associated sensors, telecommunications and other equipment are mounted on the towers. Photos of lattice met towers and typical installation are provided in Figure B-2. Photos of tubular met towers and typical installation are provided in Figure B-3.

The lattice towers will have a 12-foot-long sensor mounting boom mounted perpendicular to the top of the met tower and guyed to it. This boom is required to provide secure, reliable attachment of the sensors to the met tower while avoiding any effects of the met tower itself on collected data. The tubular towers have shorter booms, approximately 6 feet in length. Sensors will be attached to each end of the boom, approximately 5 feet out from the met tower. Figure B-4 illustrates one side of the boom and a wind sensor attached to the met tower, as well as the temperature and wind direction sensors.



Potential Met Tower Sites	Maintained Road
Stream Crossing	Existing Winter Road
	Existing Skid Trail
	Potential New Access Trail

Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

Sisk Mountain
Proposed Meteorological Tower Sites and Access

FIGURE: B-1

249 Western Ave
Augusta, ME 04330

TRC

Created: 3/10/2009

S:\Projects\TRC\Augusta\165796-Sisk_Mtn\MXD\LOCATION\Fig_B1_Sisk_Mt_Location_Map_USGS_11x17_020509.mxd

Figure B-2: Met Tower (Lattice Style) Installation Photographs

Figure B-2a: Setting the base

Figure B-2b: Attaching the first section

Figure B-2c: Raising a section

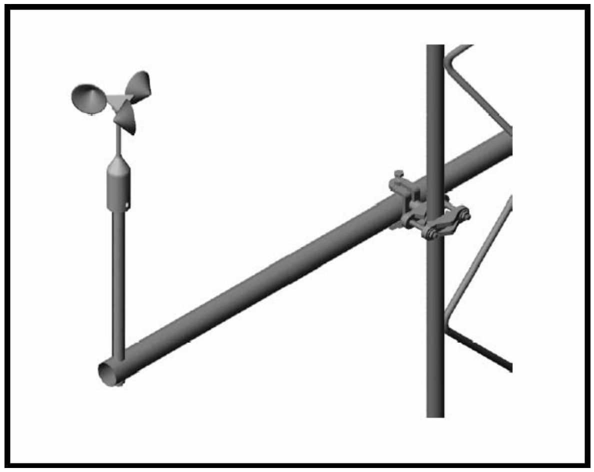
Figure B-2d: A climber near the top of a complete tower with booms and guys

Figure B-3: Met Tower (Tubular Style) Installation Photographs

Figure B-3a: Base plate of a tubular met tower

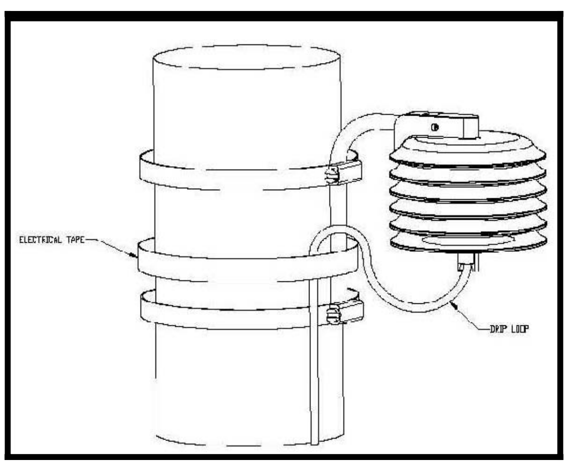
Figure B-3b: A tubular structure with guys and mulched guy corridor

Figure B-4: Illustrations of Met Tower Measurement Components



Boom and Wind Sensor

Wind Direction Vane



Temperature Sensor

2.0 Met Tower Installation Requirements

The modular design of the towers enables them to be transported to a remote site and installed with a minimum of clearing, ground disturbance and motorized equipment.

2.1 Access

No new roads are proposed to access the met tower sites or install the met towers. Existing logging roads, clearcut areas and trails will be used as much as possible to reach the four proposed sites. This will minimize the amount of clearing and trimming of vegetation required to create access trails. Ground access will allow for the most efficient and safe installation process.

Ground access for installation of the met towers will be accomplished using existing logging roads, clearcut areas and trails as much as possible, followed by limited clearing and trimming of vegetation to improve existing access trails or create new access trails. The met tower sections and other materials will be transported to the ridge top on a sled or trailer pulled by a rubber-tracked 4x4 vehicle (shown in Figure B-5) or logging skidder. In addition, a small excavator/backhoe will be needed to install the ground anchors for the met towers, and a rock drill and compressor will be needed for bedrock anchors. A 15-foot-wide cleared path will be required to drive these machines up to most locations.

Figure B-5: Representative Tracked Vehicle for Met Tower Installation

The first leg of the proposed access route to Sisk Mountain ridge will use an existing logging road; this road will not require any improvements. Approximately one-quarter of a mile from the Gold Brook Road, the existing maintained road merges into a gravel winter road; this winter road will require minimal improvements which will include repair of a stream crossing bridge. The remainder of the route to the met tower sites will require widening of an existing skid trail to approximately 2,700 feet in elevation, where the existing trail ends. The remainder will be new access trail. A summary table of the amount of vegetation clearing and trimming required to access each site is provided in Section 3.0. The table separately lists the portion of each trail that is above and below the Protected Mountain Area zone (2,700 feet mean sea level (msl)).

Access trails have been located to provide the shortest route to the ridge top while avoiding steep slopes, wetlands and wet areas as much as practical, and minimizing the need for cutting mature trees. The resulting access trails will be 15 feet wide, but will require minimal grading, grubbing, or removal of stumps. Existing, low vegetation and small saplings will be left as ground cover to hold the soil and reduce erosion potential. Illustrations of typical clearing for access trails and additional measures to prevent erosion along the trails are provided in the Erosion and Sedimentation Control Plan (E&S Plan) provided in Exhibit H. Descriptions of existing vegetation and other habitat characteristics associated with Sisk Mountain are provided in Attachment C, Natural Resource Assessment. Limited wetland impact and a stream crossing can not be avoided for the area of the access trail where the existing winter road crosses a tributary to Gold Brook; a bridge at this location has been removed and must be replaced. Work in these areas will be in accordance with the procedures provided in the E&S Plan.

2.2 Installation

The design of the met towers makes them fairly easy to install on site. The tubular towers are assembled on the ground and the entire tower is erected in one piece. The lattice towers are extended, section by section by climbers working from an installed base; sections are lifted using a winch (see Figure B-2). The preferred means of anchoring guy wires is to pin them into bedrock using a rock drill and anchors. To date, all anchoring has been by rock anchors for the met tower installations on Kibby Range and Kibby Mountain. If rock anchors are not feasible, plate or dead-man anchors will be used. They consist of an excavation hole approximately 5 feet long, 1 foot wide and 4 feet deep is required to install each anchor. Once the anchor is installed in the hole, the excavation is backfilled with the original soil and compacted. Excavation for installation of a typical plate anchor is depicted in Figures B-6 and B-7. In limited locations, screw-in or manta-ray (arrow head) type anchors may be used.

It is possible, though very unlikely, that some blasting could be required to remove bad quality rock that is unsuitable for rock anchors but must be removed to properly install a plate anchor. Very small charges would be required, and any blasting that is needed would be done in accordance with all applicable state and federal regulations. No on-site storage of explosives will be required.

It is anticipated that a met tower can be transported to the site and installed within a few weeks, using up to a six-man crew.

Met tower sites will require initial clearing to remove potential obstacles to installation of the met tower and guy wires; this will enable safe, efficient installation. For lattice-style towers, a 100- by 100-foot area around the base of each met tower will be cleared to the ground (see Exhibit D-1 of this application); however, stumps, ground cover, and forest duff layers will not be removed, except in the area immediately under the 30-inch square base plate. Beyond that, in order to be able to attach and position guy wires and raise the met tower without significant entanglement of guy wires in vegetation, trees will be cut at ground level and other woody vegetation cut down to approximately 3 feet tall along three 6-foot wide by 65-foot long corridors that extend out from the cleared area. The tubular towers require a larger cleared area. The total cleared area required has been minimized by using cleared areas that are kite-shaped (see Exhibit D-1 of this application). All areas of exposed soil will be stabilized with mulch and revegetated in accordance with the E&S Plan. The E&S Plan also contains a typical site plan showing the dimensions and orientation of the clearing and trimming needed for the met tower locations.

Figure B-6: Excavation for Ground Anchor Installation

Figure B-7: Installed Ground Anchor

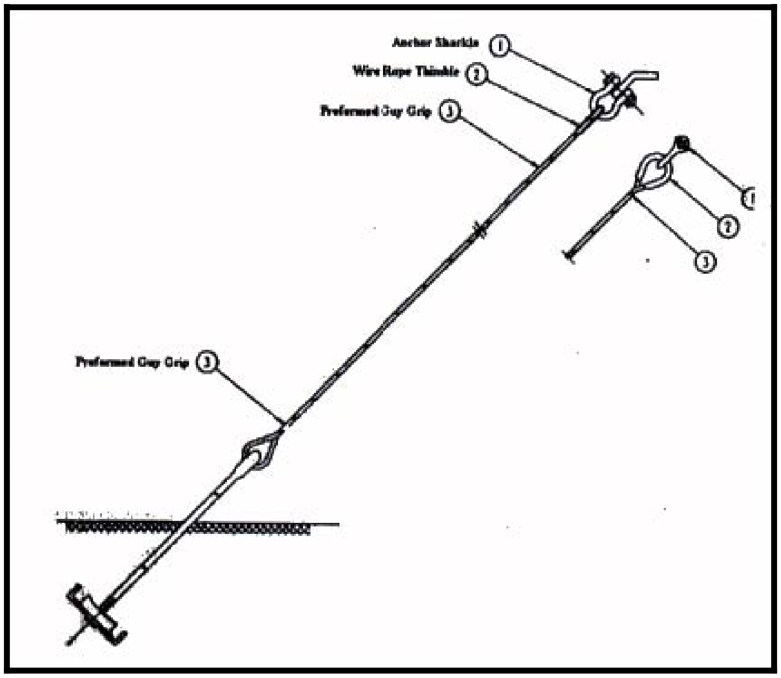


Figure B-7a: Schematic of installed anchor

Figure B-7b: An installed anchor, backfilled and mulched

3.0 Vegetation Clearing and Trimming Summary

The site for the proposed lattice met tower will require approximately 0.25 acre of clearing. Each tubular tower site will require approximately 1.1 acres of clearing. Approximately 3.8 acres of clearing are expected in association with access. Table B-1 provides a summary of the vegetation clearing and trimming requirements needed to install access roads.

Once the met towers and other equipment are installed and operational, only a 4-foot wide access trail will be maintained in an herbaceous state within the new or improved access trails to the base of each met tower to allow access by foot, ATV or snowmobile for operation and maintenance. Woody vegetation within the 4-foot maintained access trail will be cut at ground level once annually if it exceeds 2 feet tall. The vegetation outside the 4-foot maintained area will be allowed to revert naturally to a forested condition. Branches that overhang the maintained access trail will be trimmed at the edge of the 4-foot-wide area. The total area that will be maintained in this way is approximately 1 acre. It is anticipated that the area outside the maintained access trail (approximately 2.8 acres) will revert to scrub/shrub conditions within approximately 5 to 10 years and to mature forest within approximately 50 to 70 years (see table B-1).

In the event that unexpected met tower maintenance is needed which requires the use of a large piece of mobile equipment (e.g., a backhoe), the access trails would need to be re-established to approximately 15 feet wide. In such an instance, some re-cleared area may be needed around the base of the met tower. The same clearing procedures and erosion and sedimentation control safeguards would be used, and Land Use Regulation Commission (LURC) staff would be notified of such an event, prior to any re-clearing.

Table B-1: Summary of Required Vegetation Clearing and Trimming for Access Trails

Area Potentially Subject to Clearing [1]	Linear Distance to be Cleared (ft.)		Area to be Cleared (ac.)		Area to be Allowed to Revegetate (ac.)	
	Below 2,700' msl	**Above 2,700' msl**	**Below 2,700' msl**	**Above 2,700' msl**	**Below 2,700' msl**	**Above 2,700' msl**
Maintained Road [2]	N/A	N/A	N/A	N/A	N/A	N/A
Existing Winter Road [2]	N/A	N/A	N/A	N/A	N/A	N/A
Existing Skid Trail [2]	N/A	N/A	N/A	N/A	N/A	N/A
New Access Trail from Skid Trail to Ridge [3]	N/A	1373.7	N/A	0.5	N/A	0.3
Junction of ascending trail and ridge trail to met tower site 2 [3]	N/A	2198.8	N/A	0.8	N/A	0.6
Trail from met tower site 2 to met tower site 1 [3]	N/A	4991.8	N/A	1.7	N/A	1.3
Junction of ascending trail and ridge trail to met tower site 3 [3]	N/A	1038.2	N/A	0.4	N/A	0.3
Trail from met tower site 3 to met tower site 4 [3]	N/A	1339.6	N/A	0.5	N/A	0.3
TOTALS						
Column Totals	***0.0***	***10942.1***	***0.0***	***3.8***	***0.0***	***2.8***
Total New Cleared Area for Access Trails (acres)	3.8					
Total Access Trail Acreage to be Maintained After Met Tower Installation	1.0					

Note: All measurements are approximate based on current proposed design.

[1] As indicated on Figure B-1

[2] No significant alteration to existing vegetation needed. Therefore, no new cleared area will result.

[3] Assumes new cleared trail 15 feet wide is needed. Following installation, only a 4-foot wide access trail will be maintained to each site. The outer vegetation will be allowed to grow up.

4.0 Decommissioning and Removal

The met towers are expected to remain in operation until permanent wind turbines are installed; it is anticipated that this will occur within approximately four years of initial met tower installation. In the event the proposed wind turbine project does not move forward, met towers will be removed in a timely manner. Removal of the met towers will require a similar effort to the installation in terms of personnel and equipment requirements. The approach to anchor removal will depend on soil sensitivity and ground conditions; the anchors can be completely removed (which would involve ground disturbance), or the rods can be cut several inches below ground level leaving subterranean components in place.

ATTACHMENT C:

NATURAL RESOURCES ASSESSMENT

TABLE OF CONTENTS

LIST OF FIGURES

1.0 Introduction

This document has been prepared to provide information concerning regulated and environmentally sensitive resources that may be impacted by installation of the proposed Sisk Mountain Wind Power Project meteorological towers (met towers). A general assessment of the project area has been developed and, for each site where project work is proposed, specific information on the natural community characteristics, wildlife, the presence or absence of regulated wetlands, and general soil characteristics are also provided. In Section 4.0, a general discussion of potential project impacts to natural resources is presented.

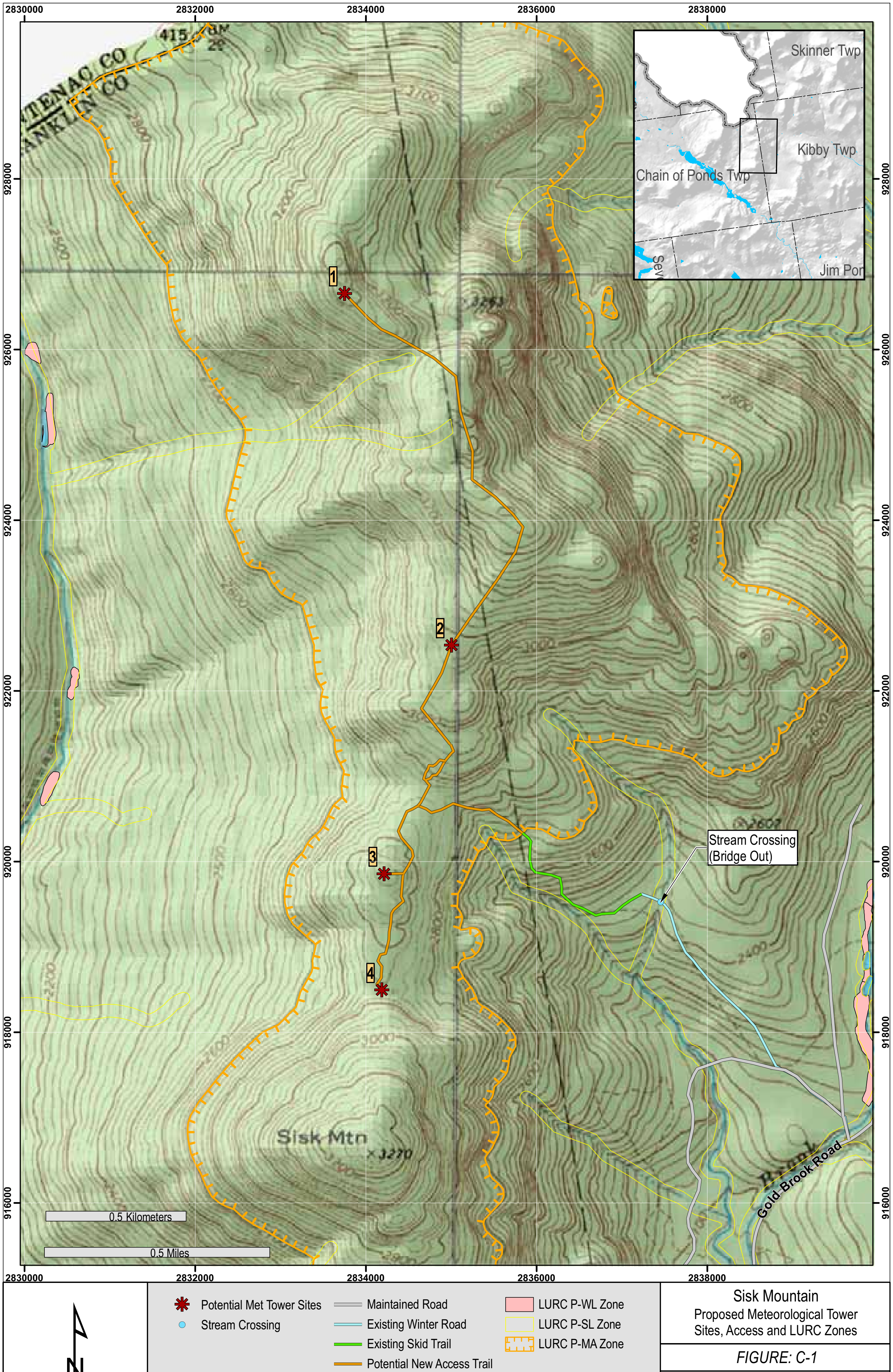
Four met tower sites are addressed in this assessment, as shown in Figure C-1. These are all located along the ridge of Sisk Mountain. Figure C-1 also illustrates proposed access trails to the met tower locations.

2.0 General Environmental Characteristics of Project Area

The proposed met tower sites and associated accessways are located in the Boundary Mountain Range in Franklin County, Maine. This area is part of the New England-Adirondack Province ecoregion as described by Keys et al. (1995). The region is characterized by a forested, mountainous landscape with many peaks exceeding 2,000 feet above mean sea level (msl). In addition, the area has numerous first, second, and third order streams that are in the Dead River drainage. The vast majority of the land in the vicinity of the proposed project area is forest that is managed for the wood products industry. Much of the forest has been cut extensively within the past century, and there are a number of regenerating clear-cuts in the area. There is an existing network of gravel roads that have been constructed for forest management purposes. Forest cover types in this region are composed of a mix of softwood and hardwood species. Specific vegetation community types found in the vicinity of the proposed met tower sites and associated access trails are described in the following sections.

3.0 Natural Resource Description

The following sections are general descriptions of natural resources at the proposed met tower sites and in the vicinity of the associated access trails. This includes descriptions of common vegetation and community types, slopes and soil types, wetlands and waterbodies, general wildlife resources, significant natural communities, and significant wildlife habitats. These descriptions are based on review of existing information (e.g., previous applications for these sites, Maine Natural Areas Program natural community classifications, etc.) and data collected during recent site inspections. County soil survey information is available for this area. For the purposes of met tower installation, a basic description of soils based on the county soil survey has been determined to be more than adequate (personal communication with the State Soil Scientist 2009), and is provided.



Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

Sisk Mountain

Proposed Meteorological Tower Sites, Access and LURC Zones

FIGURE: C-1

249 Western Ave
Augusta, ME 04330

TRC

Created:
3/10/2009

Three natural community types, consistent with those described in Natural Landscapes of Maine (Gawler and Cutco 2004), potentially occur in the proposed project area. These include the Spruce-Northern Hardwoods Forest, Spruce-Fir-Wood Sorrel-Feathermoss Forest, and Fir-Heartleaved Birch Subalpine Forest. The Spruce-Northern Hardwoods Forest typically occurs at lower elevations in this area and transitions into the Spruce-Fir-Wood Sorrel-Feathermoss Forest community type at higher elevations, with the Fir-Heartleaved Birch Subalpine Forest community found in the highest elevations in this area. The cover-types found in this area generally have most of the species characteristic for each of these natural communities in appropriate settings, however most of the areas examined have been harvested and as such are not clearly defined as natural communities. Maine Natural Areas Program (MNAP) has not identified any mapped natural communities occurring on Sisk Mountain.

3.1 Sisk Mountain Ridge and Associated Access Trail Description

3.1.1 Vegetation/Natural Communities

The Sisk Mountain access trail starts at the end of an existing logging road, and will be used to access all of the Sisk Mountain met tower sites. Most areas on Sisk Mountain that are below 2,700 feet have been harvested in the last 40 years, and much of the forest above 2,700 feet was also harvested in the past century. Any areas not recently harvested in the vicinity of the access trail for Sisk Mountain would be best described as a Spruce-Northern Hardwoods Forest in the lower elevations, which would mixes into forest that are made up of the species found in the Spruce-Fir-Wood Sorrel-Feathermoss and Fir-Heartleaved Birch Subalpine Forests at higher elevations. Data requests from MNAP have not identified any mapped natural communities on Sisk Mountain. Dominant species in the Spruce-Northern Hardwoods Forest include sugar maple (*Acer saccharum*), heart-leaved paper birch (*Betula papyrifera* var. *cordifolia*), and red spruce (*Picea rubens*) trees, saplings and shrubs, and hobblebush (*Viburnum alnifolium*) shrubs. Common herbaceous plants included mountain woodfern (*Dryopteris campyloptera*) and intermediate woodfern (*Dryopteris intermedia*), northern wood sorrel (*Oxalis Montana*), Canada dogwood (*Cornus Canadensis*), and bluebead lily (*Clintonia borealis*), long beech fern (*Thelypteris phegopteris*), starflower **(***Trientalis borealis***)**, red raspberry (*Rubus idaeus*), and wild sarsaparilla (*Aralia nudicaulis*). Red Spruce and balsam fir (*Abies balsamia*) trees, saplings, and shrubs are dominant species in the Spruce-Fir-Wood Sorrel-Feathermoss Forest communities, with an herbaceous layer often consisting of northern wood sorrel, mountain woodfern, bluebead lily, and Canada dogwood. Balsam fir and heart-leaved paper birch are the dominant trees, saplings, and shrubs in the Fir-Heartleaved Birch Subalpine Forest communities with an herbaceous layer that contains northern wood sorrel, mountain woodfern, and Canada dogwood.

3.1.2 Soils and Slope Characteristics

Access to met towers on Sisk Mountain is along one trail which starts at the end of an existing logging road. The trail extends from this point up to the ridge top and more or less follows the ridge top to each met tower site. The trail is sited to avoid excessively steep slopes and wet areas. As with other soils in the area, these soils are formed in glacial till. Soils found in the lower reaches of the trail have a relatively thick organic layer underlain by a thick mineral layer. Rocks are not common in these soils. As the proposed trail gains elevation, the organic and mineral layers thin, rocks become common, and bedrock outcrops are found in some areas of the ridge. Slopes of the trail range from 0 to 25 percent, but in most areas along the ridge, the slopes range between 5 and 15 percent.

3.1.3 Wetlands/Waterbodies

One wetland is known to occur within the proposed project area; this wetland is associated with a stream which is crossed by the existing logging road access. A culvert at this site was removed after this road was no longer actively used for timber harvesting. There will not be any permanent wetland impacts associated with construction and use of the access trails. A temporary timber mat bridge will be placed at this crossing to span the stream and associated wetland during clearing, construction, and geotechnical survey activities. If these activities are performed during winter and frozen ground conditions, the potential for impacts to soils is minimal. When spring thaw arrives, equipment access will be restricted until soil conditions are appropriate (i.e., not saturated).

A soil survey and wetland delineation effort, with protocol and methodology developed in consultation with the State Soil Scientist, will be performed once snow cover is gone. If access and construction activities must continue after spring thaw, equipment will also be restricted until the soil survey and wetland delineation determine there are no wetlands within the trail area.

3.1.4 Wildlife Resources

A number of wildlife species are known to occur in the vicinity of Sisk Mountain. Extensive field studies have been performed in the immediate area of Sisk Mountain in recent years relating to wind power development. Bird species that have been documented at high elevations (above 2,700 feet msl) include blackpoll warbler (*Dendroica striata*), yellow-rumped warbler (*Dendroica coronata*), Nashville warbler (*Vermivora ruficapilla*), winter wren (*Troglodytes troglodytes*), Swainson's thrush (*Catharus ustulatus*), dark-eyed junco (*Junco hyemalis*), common raven (*Corvus corax*), ruby-crowned kinglet (*Regulus calendula*), boreal chickadee *(Poecile hudsonicus)* and cedar waxwing (*Bombycilla cedrorum*). Evidence of moose (*Alces alces*) and black bear (*Ursus americanus*) has also been observed on ridges in the project vicinity.

Bird species documented at lower elevations (below 2,700 feet msl) include winter wren, white-throated sparrow (*Zonotrichia albicollis*), Swainson's thrush, blackpoll warbler, Nashville warbler, common yellowthroat (*Geothlypis trichas*), magnolia warbler (*Dendroica magnolia*), black-throated green warbler (*Dendroica virens*), veery (*Catharus fuscescens*), Lincoln's sparrow (*Melospiza lincolnii*), song sparrow (*Melospiza melodia*), black-throated blue warbler *(Dendroica caerulescens)*, blackburnian warbler (*Dendroica fusca*), black-capped chickadee

(*Parus atricapillus*), chestnut-sided warbler (*Dendroica pensylvanica*), ruffed grouse (*Bonasa umbellus*) and red-tailed hawk (*Buteo jamaicensis*). Mammals known to occur at lower elevations in the project vicinity include moose, black bear and whitetail deer (*Odocoileus virginianus*).

3.1.5 Significant Natural Communities

In a letter dated February 9, 2009, the Maine Natural Areas Program (MNAP) provided information regarding rare and exemplary botanical features in the vicinity of Sisk Mountain in response to our request for information. The letter, with associated list of rare species occurrences and map, is provided in Appendix A.

The MNAP search revealed two occurrences of lesser wintergreen (*Pyrola minor*), a S2-ranked state species of special concern, within four miles of Sisk Mountain. One of these occurrences is on the east slope of Sisk Mountain.

The MNAP search revealed five occurrences of boreal bedstraw (*Galium kamtschaticum*), a S2-ranked state threatened species, within four miles of Sisk Mountain. One of these occurrences is on the east slope of Sisk Mountain.

The MNAP search revealed one occurrence of giant rattlesnake-plantain (*Goodyera oblongifolia*), a S1-ranked state endangered species, within four miles of Sisk Mountain. This occurrence is not located on Sisk Mountain.

3.1.6 Significant Wildlife Habitat

Correspondence was sent to MDIF&W and USFWS requesting information about known species issues in the project vicinity. The MDIF&W responded on February 10, 2009. Agency correspondence is provided in Appendix A.

In its letter on February 10, 2009, MDIF&W stated that the project area is not associated with any known essential wildlife habitats, deer wintering areas, inland waterfowl/wading bird habitats, or significant vernal pools. The area is, however, associated with an historic golden eagle (*Aquila chrysaetos*) nest site. This site is associated with a series of cliffs located on the southern slope of Sisk Mountain. This nest site has not been occupied by eagles since the 1970's.

3.2 Staging Area

Staging areas for the met towers and geotechnical surveys will be in existing gravel pits or other open, level, graded areas.

4.0 Anticipated Natural Resource Impacts

4.1 Vegetation/Natural Communities

Clearing will consist of cutting trees and shrubs close to the ground to enable met tower construction vehicles and equipment to access the site. Lattice-type tower sites will require a cleared area of approximately 100-feet by 100-feet, (approximately 0.25 acre in size) or up to approximately 1.09 acres for tubular tower sites. Trails will be cleared to an initial 15-foot width. In total, approximately 11,000 linear feet of new trail will be established for access, which will translate to approximately 3.8 acres of new clearing. The total new cleared area for the project, including improvements to existing trails, clearing of met tower sites, and new trails will be approximately 8 acres. For a summary of required vegetation clearing and trimming for the trails, see Table C-1.

Stumps and topsoil will not be removed and there will not be any grading or soil disturbance, except to install met tower anchors. Soil disturbance on access trails and at met tower sites may also occur inadvertently as a result of moving equipment. By leaving stumps and topsoil intact, a natural, native seed base will also be kept intact; this will encourage natural revegetation by both sprouting stumps (hardwoods) and seeds. Vegetation will be maintained at low heights by trimming, which will encourage the growth of native herbaceous vegetation. Trails will be allowed to revegetate with shrubs and trees to a minimum width of approximately four feet; as such, only approximately 1.0 acre of cleared area will be maintained for access. This minimal amount of clearing will not result in any adverse impacts to the natural communities found in these areas.

There are two known occurrences of state listed plant species within 1000 meters of the proposed project development; these include one occurrence of lesser wintergreen (*Pyrola minor*; a S2-ranked state species of special concern), and one occurrence of boreal bedstraw (*Galium kamtschaticum*; a S2-ranked state threatened species). The proposed project development does not encroach on these known locations and will not cause impacts to these areas. Lesser wintergreen and boreal bedstraw are well known to the applicant, due to field surveys done in the immediate area. Both of these plants live in close association with surface water resources, in close proximity to stream channels in the case of lesser wintergreen or wetlands in the case of boreal bedstraw. Since these areas will be avoided to the extent possible, no impact is anticipated.

Table B-1: Summary of Required Vegetation Clearing and Trimming for Access Trails

Area Potentially Subject to Clearing [1]	Linear Distance to be Cleared (ft.)		Area to be Cleared (ac.)		Area to be Allowed to Revegetate (ac.)	
	Below 2,700' msl	**Above 2,700' msl**	**Below 2,700' msl**	**Above 2,700' msl**	**Below 2,700' msl**	**Above 2,700' msl**
Maintained Road [2]	N/A	N/A	N/A	N/A	N/A	N/A
Existing Winter Road [2]	N/A	N/A	N/A	N/A	N/A	N/A
Existing Skid Trail [2]	N/A	N/A	N/A	N/A	N/A	N/A
New Access Trail from Skid Trail to Ridge [3]	N/A	1373.7	N/A	0.5	N/A	0.3
Junction of ascending trail and ridge trail to met tower site 2 [3]	N/A	2198.8	N/A	0.8	N/A	0.6
Trail from met tower site 2 to met tower site 1 [3]	N/A	4991.8	N/A	1.7	N/A	1.3
Junction of ascending trail and ridge trail to met tower site 3 [3]	N/A	1038.2	N/A	0.4	N/A	0.3
Trail from met tower site 3 to met tower site 4 [3]	N/A	1339.6	N/A	0.5	N/A	0.3
TOTALS						
Column Totals	***0.0***	***10942.1***	***0.0***	***3.8***	***0.0***	***2.8***
Total New Cleared Area for Access Trails (acres)	3.8					
Total Access Trail Acreage to be Maintained After Met Tower Installation	1.0					

Note: All measurements are approximate based on current proposed design.

[1] As indicated on Figure B-1

[2] No significant alteration to existing vegetation needed. Therefore, no new cleared area will result.

[3] Assumes new cleared trail 15 feet wide is needed. Following installation, only a 4-foot wide access trail will be maintained to each site. The outer vegetation will be allowed to grow up.

4.2 Soils and Slopes

Minimal soil disturbance will result from installation of the met towers, and locations for the access trails have been selected that minimize potential impacts to soils and slopes. A detailed Erosion and Sedimentation Control Plan (provided in Exhibit H) has been developed that will be implemented to ensure that appropriate measures are taken and monitored throughout the installation effort and until full soil stabilization has occurred.

4.3 Wetlands/Waterbodies

None of the met tower sites will require impact to wetlands or waterbodies. The existing access road crosses a stream with associated wetland, and the culvert has been removed. A temporary mat crossing will be installed at this location that will fully span the approximately 6-foot wide stream channel.

4.4 Wildlife Resources

Potential impact to species utilizing the project area is anticipated to be generally limited to temporary disruption during installation efforts. Also, a small area of additional edge habitat will be provided from the proposed vegetation clearing. Once the met towers are installed and operational, species use of the project area is expected to continue as it did prior to met tower installation.

Met towers, such as those proposed, have a minimal potential to result in collision impact to birds and bats. Detailed avian and bat studies were conducted at met tower sites on Kibby Range and Kibby Mountain, which are directly adjacent to Sisk Mountain, in 2006 and 2007. Ground searches for carcasses or feathers, done during migration seasons at the met tower sites on Kibby Mountain and Kibby Range did not reveal any evidence of avian collisions.

In this proposal, recommendations included in a September 14, 2000, guidance document published by the USFWS addressing tower installation have been considered. Due to the purpose and nature of the proposed temporary structures, adherence to the recommendations is not possible. However, measures will be taken throughout the use of the proposed structures to monitor and minimize impact to the extent possible. A brief summary of the USFWS guidance and a project response is followed by a discussion of proposed actions for impact minimization.

1. *Collocate equipment on existing towers, where possible.* Given the lack of existing towers in the project vicinity and the purpose for the proposed structures (which is to collect on-site meteorological data in support of wind project feasibility) such co-location can not reasonably be proposed. An attempt has been made to propose the minimum number of met towers required to sufficiently understand the wind resource in the project area. The complexity of terrain, however, requires positioning of several met towers along the ridgeline location.

2. *Utilize towers of less than 199 feet in height, and avoid lighting, if possible.* The proposed structures are 197 feet (60 meters) tall, in order to collect meteorological information at a likely wind turbine rotor height. The structures will also be used for ecological data collection purposes, and having the ability to collect data at potential rotor height improves the accuracy of collected data. No lighting will be necessary for these towers.

3. *Avoid siting towers in or near wetlands, other known bird concentration areas, in known migratory or daily movement flyways, or in habitat of threatened or endangered species.* The met towers will not be located in or near wetlands, nor in known bird concentration areas. Correspondence has been sent to MDIFW and USFWS to confirm that no known threatened or endangered species habitat is located in the tower areas. Based upon prior work completed in the project area, the met towers are not located in known migratory or daily movement flyways. However, work will continue with regard to avian seasonal movement, and ongoing consideration to that information can be reflected in the duration and location of specific met towers.

4. *Use minimum lighting required by FAA.* Lighting will not be used on these towers.

5. *Use daytime visual markers on guy wires.* Markers will not be used on these towers. Avian mortality survey results from met tower sites on the Kibby Wind Power Project indicate that towers represent little risk to birds as no mortalities have been found at these sites.

6. *Avoid or minimize habitat loss.* Each met tower will be sited to utilize the minimum clearing necessary for adequate data capture.

7. *Relocation or seasonal restrictions should be considered for areas with significant numbers of breeding, feeding or roosting birds.* Based on currently available information and recent studies of other nearby ridges, the project location is not significantly more utilized by breeding, feeding or roosting birds than other locations in the vicinity.

8. *Design the structures for multiple uses.* In this instance, the met towers will be used for collection of ecological data as well as for their primary purpose of collecting information about wind characteristics.

9. *Down-shield security lighting*. No security lighting is proposed.

10. *Access for monitoring*. The met towers will be utilized by the project for additional ecological surveys. The collected information may be used to refine met tower locations and will also be utilized in determining the feasibility and design of proposed wind turbines in specific project locations. As is customary during any permitting process, regulatory agencies involved with review of the project will be allowed access to the area, with appropriate coordination with the landowner.

11. *Remove towers within 12 months of cessation of use.* The met towers will be removed following their use, as addressed in Attachment B.

Impact potential has been minimized by siting as few met towers as possible for achieving study objectives, utilizing the towers for the dual purpose of ecological monitoring, and avoiding known significant resource areas.

4.5 Significant Natural Communities/Significant Wildlife Habitat

No significant natural communities or significant wildlife habitats are known to exist in the project area; however, there are historic records of golden eagle nesting activity on the southern slope of Sisk Mountain. The proposed project development is separated from the location of this historic nest site by the southern summit of Sisk Mountain and a distance of approximately 1.5 miles. TRC biologists have visited this location numerous times in recent years for the purpose of observing presence or absence of golden eagle nesting activity; no golden eagles or nesting activities have been observed. Additional consultation with MDIFW will be ongoing regarding this site.

5.0 References

Cowardin, L.M., V. Carter, F. Golet, and E.T. Laroe. 1979. Classification of Wetlands and Deppwater Habitats of the United States. United States Fish and Wildlife Service, Biological Services Program; FWS/OBS-79/31.

Gawler, S.C., and A.R. Cutco. 2004. Natural Landscapes of Maine: A Classification of Vegetated Natural Communities and Ecosystems. Maine Natural Areas Program, Department of Conservation, Augusta, Maine. 349 pp.

Keys, Jr., C. Carpenter, S. Hooks, F. Koenig, W.H. McNabb, W. Russell, and M.L. Smith. 1995. Ecological Units of the Eastern United States – First Approximation. Atlanta, GA: U.S. Department of Agriculture, Forest Service.

Personal Communication, David Rocque, 2005. Telephone conversation between David Rocque, Maine State Soil Scientist, and Dana Valleau of TRC.

APPENDIX A

AGENCY CORRESPONDENCE

TRC

249 Western Avenue
Augusta, ME 04330

207.621.7000 PHONE
207.621.7001 FAX

www.TRCsolutions.com

February 5, 2009

Mr. Mark McCullough
U.S. Fish and Wildlife Service
Maine Ecological Services Office
1168 Main Street
Old Town, ME 04468

Subject: **Information Request for State Listed T&E Species**

Dear Mark:

TRC Engineers, LLC (TRC) is requesting information regarding the known location of state-listed threatened or endangered (T&E) plant and animal species, and associated essential or significant wildlife habitats in the vicinity of Sisk Mountain in Chain of Ponds and Kibby Townships in northwestern Maine.

Sisk Mountain is currently under evaluation for development of a wind power facility. As shown on the attached map, four locations have been proposed for installation of meteorological towers (met towers) which will gather information necessary to determine the suitability of Sisk Mountain for wind tower development. The proposed met towers will be 65 meters in height and will support instrumentation to collect site-specific data on wind speed, direction, and other meteorological information. The met towers will also support data collection equipment for project-related ecological studies.

Installation and operation of this equipment will not require the construction of any new roads or unvegetated surfaces. Limited clearing will be required for proper installation of the met towers and operation of associated equipment, and to create access trails to the sites. Existing logging roads, skidder paths and trails will be used as much as possible to minimize need for new trails. Existing and new trails will also be used for geotechnical investigations, which area also part of the current proposal.

The information you provide will be incorporated into a permit application to the Maine Land Use Regulation Commission (LURC) for installation of the met towers and geotechnical investigations. TRC is also contacting the appropriate state agencies with a similar request for information related to the LURC met tower application.

Please me at TRC (207)-621-7093 or dvalleau@trcsolutions.com with any questions you may have. I look forward to your reply within approximately two weeks, if possible. Thank you for your time.

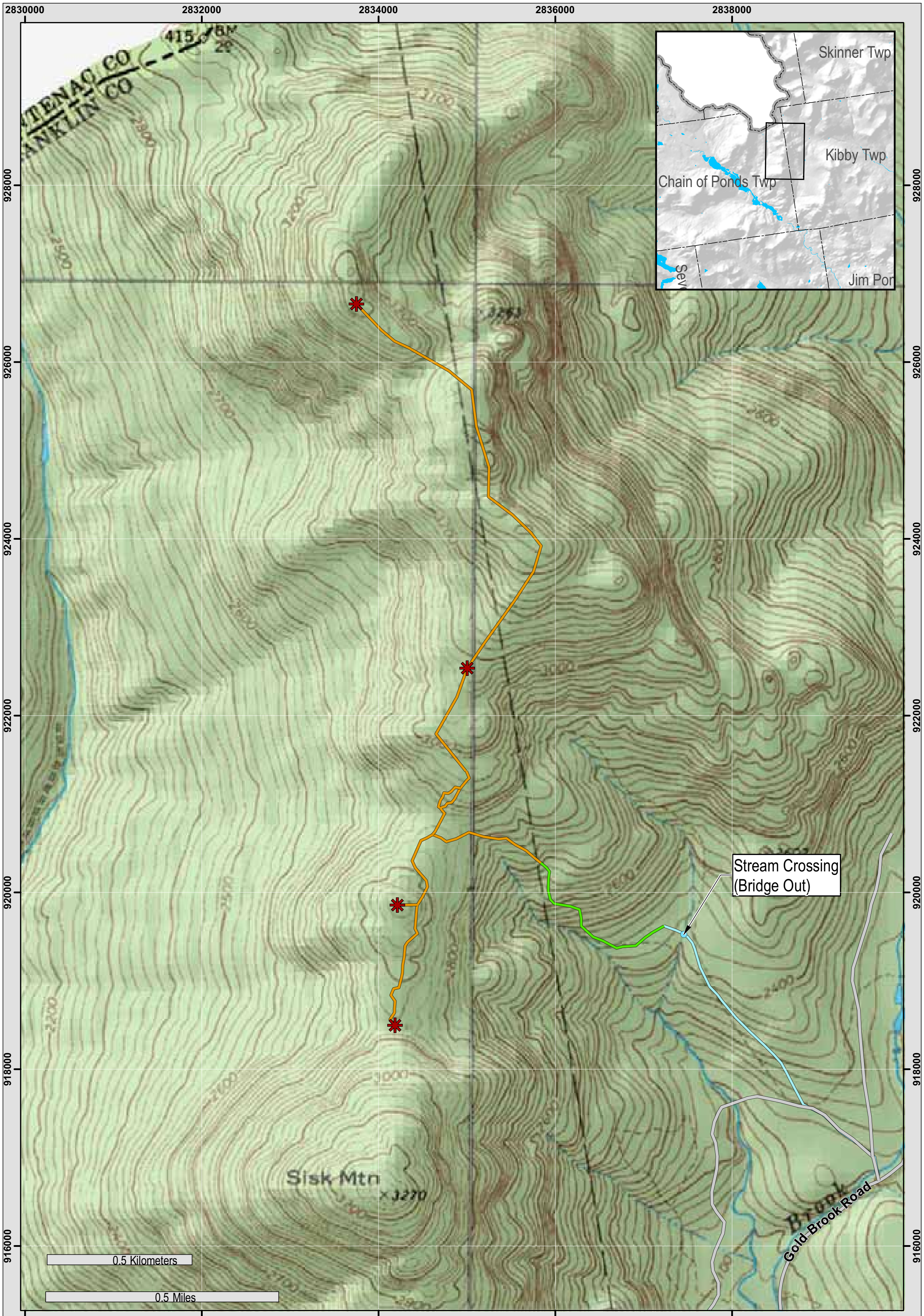
Sincerely,

Dana Valleau

Dana Valleau
Environmental Scientist

Enclosure

Cc: Christine Cinnamon-Langille, TransCanada Energy, Ltd.



TRUE NORTH

Potential Met Sites

Stream

Maintained Road

Existing Winter Road

Existing Skid Trail

Potential Access Trail

Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

Sisk Mountain
Proposed Meteorological Tower
Sites and Access

Met Tower and Access Road Siting

249 Western Ave
Augusta, ME 04330

TRC

Created:
1/27/2009

STATE OF MAINE
DEPARTMENT OF CONSERVATION
93 STATE HOUSE STATION
AUGUSTA, MAINE
04333-0093

JOHN ELIAS BALDACCI
GOVERNOR

PATRICK K. MCGOWAN
COMMISSIONER

February 9, 2009

Dana Valleau
TRC
249 Western Avenue
Augusta, ME 04330

Re: Rare and exemplary botanical features, Sisk Mountain, Chain of Ponds and Kibby Townships, Maine.

Dear Ms. Valleau:

I have searched the Natural Areas Program's Biological and Conservation Data System files in response to your request of February 5, 2009 for information on the presence of rare or unique botanical features documented from the vicinity of the project site in Chain of Ponds and Kibby Townships, Maine. Rare and unique botanical features include the habitat of rare, threatened, or endangered plant species and unique or exemplary natural communities. Our review involves examining maps, manual and computerized records, other sources of information such as scientific articles or published references, and the personal knowledge of staff or cooperating experts.

Our official response covers only botanical features. For authoritative information and official response for zoological features you must make a similar request to the Maine Department of Inland Fisheries and Wildlife, 284 State Street, Augusta, Maine 04333.

According to the information currently in our Biological and Conservation Data System files, there are no rare botanical features documented specifically within the project area. This lack of data may indicate minimal survey efforts rather than confirm the absence of rare botanical features. We recommend that the site be inventoried by a qualified field biologist to ensure that no undocumented rare features are inadvertently harmed. Data from field surveys should be provided to the Maine Natural Areas Program for use in evaluating any future development at the site.

If a field survey of the project area is conducted, please refer to the enclosed supplemental information regarding rare and exemplary botanical features documented to occur in the vicinity of the project site. The list may include information on features that have been known to occur historically in the area as well as recently field-verified information. While historic records have not been documented in several years, they may persist in the area if suitable habitat exists. The enclosed list identifies features with potential to occur in the area, and it should be considered if you choose to conduct field surveys.

MAINE NATURAL AREAS PROGRAM
MOLLY DOCHERTY, DIRECTOR

PHONE: (207) 287-8044
FAX: (207) 287-8040
TTY: (207) 287-2213

This finding is available and appropriate for preparation and review of environmental assessments, but it is not a substitute for on-site surveys. Comprehensive field surveys do not exist for all natural areas in Maine, and in the absence of a specific field investigation, the Maine Natural Areas Program cannot provide a definitive statement on the presence or absence of unusual natural features at this site.

The Natural Areas Program is continuously working to achieve a more comprehensive database of exemplary natural features in Maine. We would appreciate the contribution of any information obtained should you decide to do field work. The Natural Areas Program welcomes coordination with individuals or organizations proposing environmental alteration, or conducting environmental assessments. If, however, data provided by the Natural Areas Program are to be published in any form, the Program should be informed at the outset and credited as the source.

The Natural Areas Program has instituted a fee structure of $75.00 an hour to recover the actual cost of processing your request for information. You will receive an invoice for $75.00 for our services.

Thank you for using the Natural Areas Program in the environmental review process. Please do not hesitate to contact me if you have further questions about the Natural Areas Program or about rare or unique botanical features on this site.

Sincerely,

Janet Gannon
Associate Information Manager
Maine Natural Areas Program
207-287-8044

Janet.Gannon@maine.gov

Enclosures

Rare and Exemplary Botanical Features in the Project Vicinity

Documented within a Four-Mile Radius of Sisk Mountain, Chain of Ponds and Kibby Twonships, Maine.

Scientific Name / Common Name	Last Seen	Global Rarity Rank	State Rarity Rank	State Protection Status	Habitat Description
Pyrola minor Lesser Wintergreen	2006-07-04	G5	S2	SC	Moist woods.
Pyrola minor Lesser Wintergreen	1999-07	G5	S2	SC	Moist woods.
Galium kamtschaticum Boreal Bedstraw	1999-07	G5	S2	T	Cool woods, thickets, streamsides.
Galium kamtschaticum Boreal Bedstraw	1999-07	G5	S2	T	Cool woods, thickets, streamsides.
Galium kamtschaticum Boreal Bedstraw	2006-09-14	G5	S2	T	Cool woods, thickets, streamsides.
Galium kamtschaticum Boreal Bedstraw	2000-07-07	G5	S2	T	Cool woods, thickets, streamsides.
Goodyera oblongifolia Giant Rattlesnake-plantain	2004-06-29	G5?	S1	E	Dry coniferous or mixed woods.

Rare and Exemplary Botanical Features in the Project Vicinity

Documented within a Four-Mile Radius of Sisk Mountain, Chain of Ponds and Kibby Twonships, Maine.

Scientific Name / Common Name	Last Seen	Global Rarity Rank	State Rarity Rank	State Protection Status	Habitat Description
Galium kamtschaticum / Boreal Bedstraw	2006-07-04	G5	S2	T	Cool woods, thickets, streamsides.

STATE RARITY RANKS

S1	Critically imperiled in Maine because of extreme rarity (five or fewer occurrences or very few remaining individuals or acres) or because some aspect of its biology makes it especially vulnerable to extirpation from the State of Maine.
S2	Imperiled in Maine because of rarity (6-20 occurrences or few remaining individuals or acres) or because of other factors making it vulnerable to further decline.
S3	Rare in Maine (20-100 occurrences).
S4	Apparently secure in Maine.
S5	Demonstrably secure in Maine.
SH	Known historically from the state, not verified in the past 20 years.
SX	Apparently extirpated from the state, loss of last known occurrence has been documented.
SU	Under consideration for assigning rarity status; more information needed on threats or distribution.
S#?	Current occurrence data suggests assigned rank, but lack of survey effort along with amount of potential habitat create uncertainty (e.g. S3?).

Note: **State Rarity Ranks** are determined by the Maine Natural Areas Program.

GLOBAL RARITY RANKS

G1	Critically imperiled globally because of extreme rarity (five or fewer occurrences or very few remaining individuals or acres) or because some aspect of its biology makes it especially vulnerable to extinction.
G2	Globally imperiled because of rarity (6-20 occurrences or few remaining individuals or acres) or because of other factors making it vulnerable to further decline.
G3	Globally rare (20-100 occurrences).
G4	Apparently secure globally.
G5	Demonstrably secure globally.
GNR	Not yet ranked.

Note: **Global Ranks** are determined by NatureServe.

STATE LEGAL STATUS

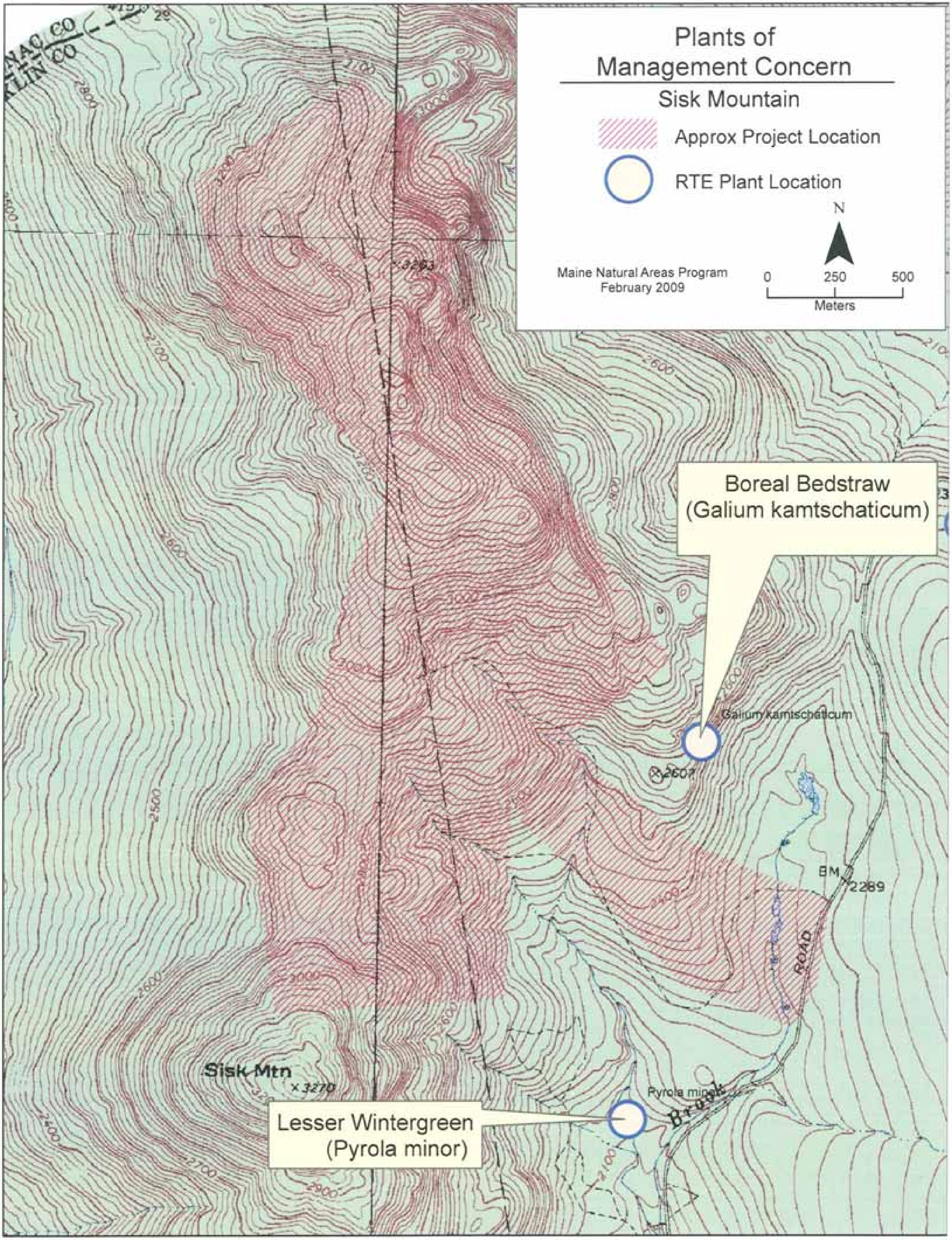
Note: State legal status is according to 5 M.R.S.A. § 13076-13079, which mandates the Department of Conservation to produce and biennially update the official list of Maine's **Endangered** and **Threatened** plants. The list is derived by a technical advisory committee of botanists who use data in the Natural Areas Program's database to recommend status changes to the Department of Conservation.

E	ENDANGERED; Rare and in danger of being lost from the state in the foreseeable future; or federally listed as Endangered.
T	THREATENED; Rare and, with further decline, could become endangered; or federally listed as Threatened.

NON-LEGAL STATUS

SC	SPECIAL CONCERN; Rare in Maine, based on available information, but not sufficiently rare to be considered Threatened or Endangered.
PE	Potentially Extirpated; Species has not been documented in Maine in past 20 years or loss of last known occurrence has been documented.

Visit our website for more information on rare, threatened, and endangered species!
http://www.mainenaturalareas.org/docs/rare_plants/factsheets.php


Plants of
Management Concern
Sisk Mountain
Approx Project Location
RTE Plant Location
N
Maine Natural Areas Program
February 2009
0
250
500
Meters
Boreal Bedstraw
(Galium kamtschaticum)
Galium kamtschaticum
Lesser Wintergreen
(Pyrola minor)
Pyrola minor
Sisk Mtn
×3270
×2607
BM
2289
ROAD
Brook

STATE OF MAINE
DEPARTMENT OF INLAND FISHERIES & WILDLIFE

JOHN ELIAS BALDACCI
GOVERNOR

WILDLIFE DIVISION
Region D
689 Farmington Road
Strong, Maine 04983

ROLAND D. MARTIN
COMMISSIONER

Phone (207) 778-3324 FAX (207) 778-3323

February 10, 2009

Dana Valleau
TRC Solutions
249 Western Ave.
Augusta, ME 04330

Dear Dana:

I received your 5 February 2009 letter requesting Significant and Essential Wildlife Habitat information associated with the proposed met tower location and potential wind facility in Chain of Ponds and Kibby Twps. Enclosed are the results of my review.

Essential Habitats:

Essential Habitats are defined as "areas currently or historically providing physical or biological features essential to the conservation of an endangered or threatened species in Maine and which may require special management considerations". Essential Habitat protection in Maine currently applies to bald eagle, roseate and least tern, and piping plover nest sites, but additional listed species may receive attention in the future.

According to MDIFW records, there are no Essential Habitats known to be associated with this property.

Significant Wildlife Habitats:

The Natural Resources Protection Act, administered by the Maine Department of Environmental Protection, provides protection to certain natural resources including Significant Wildlife Habitats. Significant Wildlife Habitats are defined by the NRPA as:

- Habitat for state and federally listed endangered and threatened species.
- High and moderate value deer wintering areas (DWAs) and travel corridors.
- High and moderate value waterfowl and wading bird habitats (WWHs), including nesting and feeding areas.
- Shorebird nesting feeding and staging areas.
- Seabird nesting islands.

According to MDIFW records, there are no Deer Wintering Areas known to be associated with this property. However, you should contact the Maine Department of Environmental Protection (DEP) for information regarding WWH and wetlands. Due to a recent administrative decision, Regional Wildlife Staff will no longer be able to provide maps and associated information regarding these Significant Wildlife Habitats. The DEP is the official state agency with jurisdiction over these habitats and will now be the source of consultation regarding these habitats. I have included contact information for each of the DEP Regional Offices:

Augusta:	17 State House Station, Augusta, Maine 04333-0017 – 1-800-452-1942
Bangor:	106 Hogan Road, Bangor, Maine 04401 – 1-888-769-1137
Portland:	312 Canco Road Portland, Maine 04103 – 1-888-769-1036
Presque Isle:	1235 Central Drive, Skyway Park, Presque Isle, Maine 04769 – 1-888-769-1053

Threatened, Endangered or Special Concern Species

Finally, the department maintains a statewide database of Threatened and Endangered wildlife species and habitats, or Species of Special Concern. In general, these records are not the product of recent or intensive surveys for T/E species. Your project area contains a historic/traditional nesting site for golden eagles and has the potential to support eagles currently. We can further discuss the importance of this species relative to your project our scheduled meeting later this month.

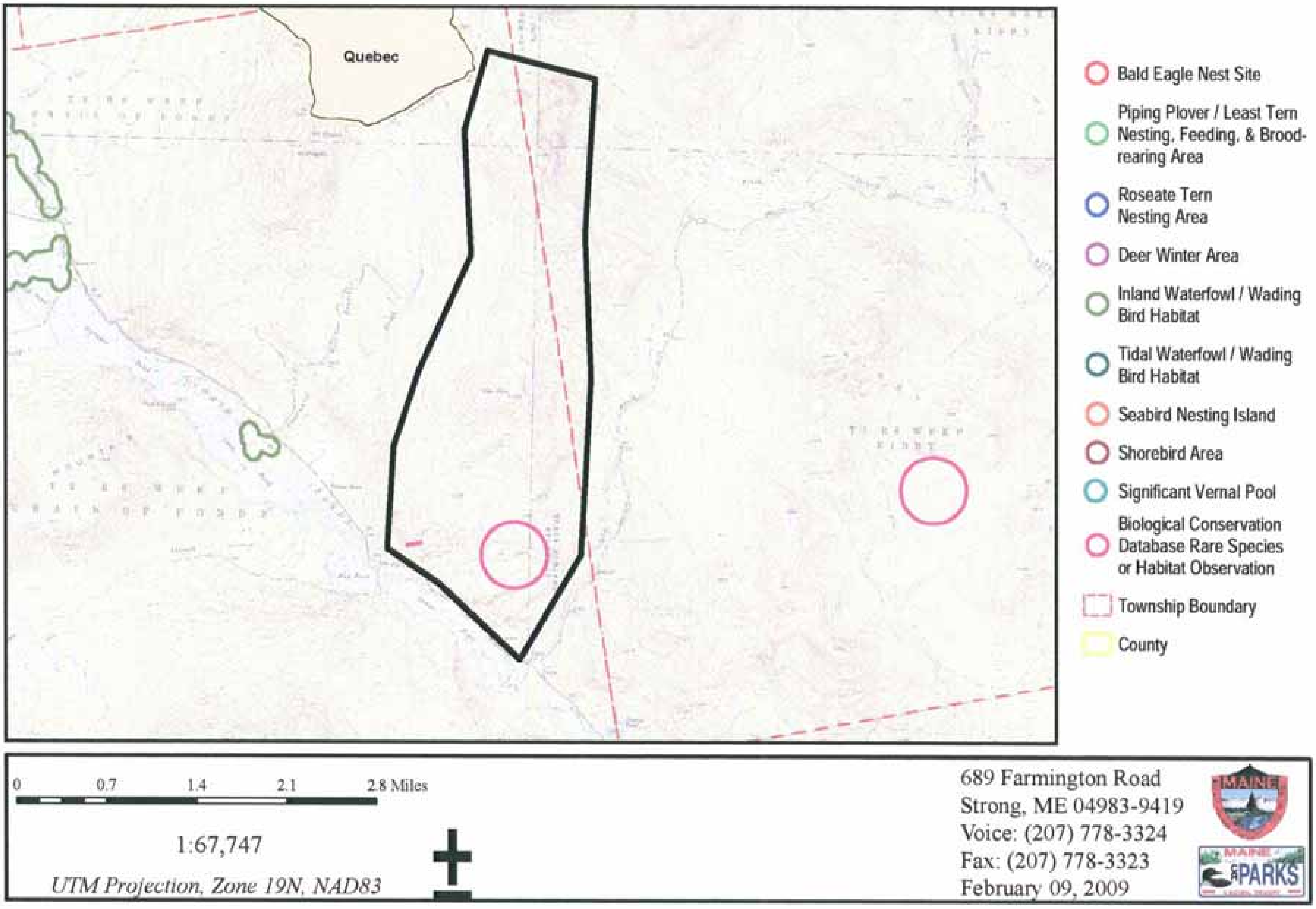
If you have any questions or would like further assistance please feel free to contact this office, we would be glad to help.

Yours truly,

Robert C. Cordes

Robert C. Cordes
Asst. Regional Wildlife Biologist

Search for Wildlife Observations & Habitat



1:67,747

UTM Projection, Zone 19N, NAD83

689 Farmington Road
Strong, ME 04983-9419
Voice: (207) 778-3324
Fax: (207) 778-3323
February 09, 2009

Maine Department of Inland Fisheries & Wildlife
689 Farmington Road, Strong, ME 04983-9419
Phone: (207) 778-3324, FAX: (207) 778-3323

Site-Specific Search of Wildlife Observations and Habitat

SEARCH PARAMETERS

County:	Franklin
IF&W Region:	D
Township(s):	Chain of Ponds Twp, Kibby Twp
Search Center:	372226 east, 5023283 north (UTM NAD83 coordinates)
Search Area:	5.26 sq. miles
Date:	Monday, February 09, 2009

RESULTS

Essential Wildlife Habitats

BALD EAGLE NEST SITES
None Found

PIPING PLOVER / LEAST TERN NESTING, FEEDING, AND BROOD-REARING AREAS
None Found

ROSEATE TERN NESTING AREAS
None Found

Natural Resource Protection Act (NRPA) Habitats

SEABIRD NESTING ISLANDS
None Found

DEER WINTER AREAS
None Found

INLAND WATERFOWL/WADING BIRD HABITATS
None Found

TIDAL WATERFOWL/WADING BIRD HABITATS
None Found

SHOREBIRD AREAS
None Found

SIGNIFICANT VERNAL POOLS
None Found

Land Use Regulation Commission (LURC) Deer Winter Areas and Seabird Nesting Islands
None Found

Rare, Threatened, or Endangered (RTE) Species Observations (Natural Heritage data)

This is an information management component of the Natural Heritage Program Network created by the Nature Conservancy. It is designed to track information on the status, life history, conservation needs, and occurrences for rare species and natural communities. MDIFW is responsible for maintaining the zoological portion of the database, which contains information on approximately 1050 animal species native to the State.

POINTS OBSERVATIONS BUFFERED BY 0.25 MILES

In the map, RTE points are surrounded by a 0.25-mile radius circle to represent the general area around the observation that should be considered for management. Ideally, the mapped polygon should show the extent of the important habitat(s) associated with the observation, but until a new landcover map of Maine becomes available, we are using simple circular buffers to approximate that area. This circular buffer is less appropriate for aquatic species for which the limit of the water body or a buffered stream segment may be more realistic. In all cases, an MDIFW biologist should investigate the habitat around a RTE observation to determine the most appropriate area for management consideration.

Classification of RTE observations as PubRev = 'Y' or PubRev = 'N' indicates whether the area around the observation should receive special management consideration based on the species involved (endangered, threatened, or rare), importance or rarity of the habitat, or whether the observation is recent or historical. Observations in RTE that are duplicated in other MDIFW datasets (e.g., Eagle Essential Wildlife Habitats) are classified here as PubRev = 'N', not because they are unimportant but because they should already be flagged elsewhere in this report. Any questions regarding RTE observations should be directed to MDIFW's Endangered & Threatened Species Group.

Code	Common Name	Survey Area
ABNKC22010*012*ME	Golden Eagle	SISK MOUNTAIN

CODE = unique identifier of observation

MAPPED HABITAT POLYGONS

Polygon observations of BCD data are based on the extent of the habitat considered important to the species or the extent of the area that was mapped by the biologist who recorded the observation. This database has not been updated since 2002 because the current map of landcover in Maine still is based on the 1992 GAP analysis.

Code	Description
GE012	Golden Eagle

CODE = unique identifier of observation

STATE OF MAINE
DEPARTMENT OF ENVIRONMENTAL PROTECTION

JOHN ELIAS BALDACCI
GOVERNOR

DAVID P. LITTELL
COMMISSIONER

February 20, 2009

TRC Solutions
Dana Valleau
249 Western Avenue
Augusta, ME 04330

Re: Request for Significant Wildlife Habitat Information
Significant Wildlife Habitat (IWWH) Map for Sisk Mountain, Kibby Township and Chain of Ponds Township

Dear Dana:

Enclosed please find maps in response to your request for information regarding the location of all Inland Wading and Waterfowl Habitats (IWWH's) in the vicinity of Sisk Mountain, which is located in Kibby Township and Chain of Ponds Township. These maps show the approximate project area and were generated using Maine Geographic Information System (GIS) habitat data layers that have been overlayed in Google Earth. This information has been provided and maintained by the Maine Department of Environmental Protection (DEP) and the Maine Department of Inland Fisheries and Wildlife (IF&W) and is now available via a link on the DEP website. ***Based on this information, it appears that there are areas mapped as IWWH habitat located throughout these townships.***

Please note that GIS data layers showing mapped vernal pools are now currently available. The project area must still be screened by a qualified professional during the appropriate identification period to determine if any other significant vernal pools are present in the project area.

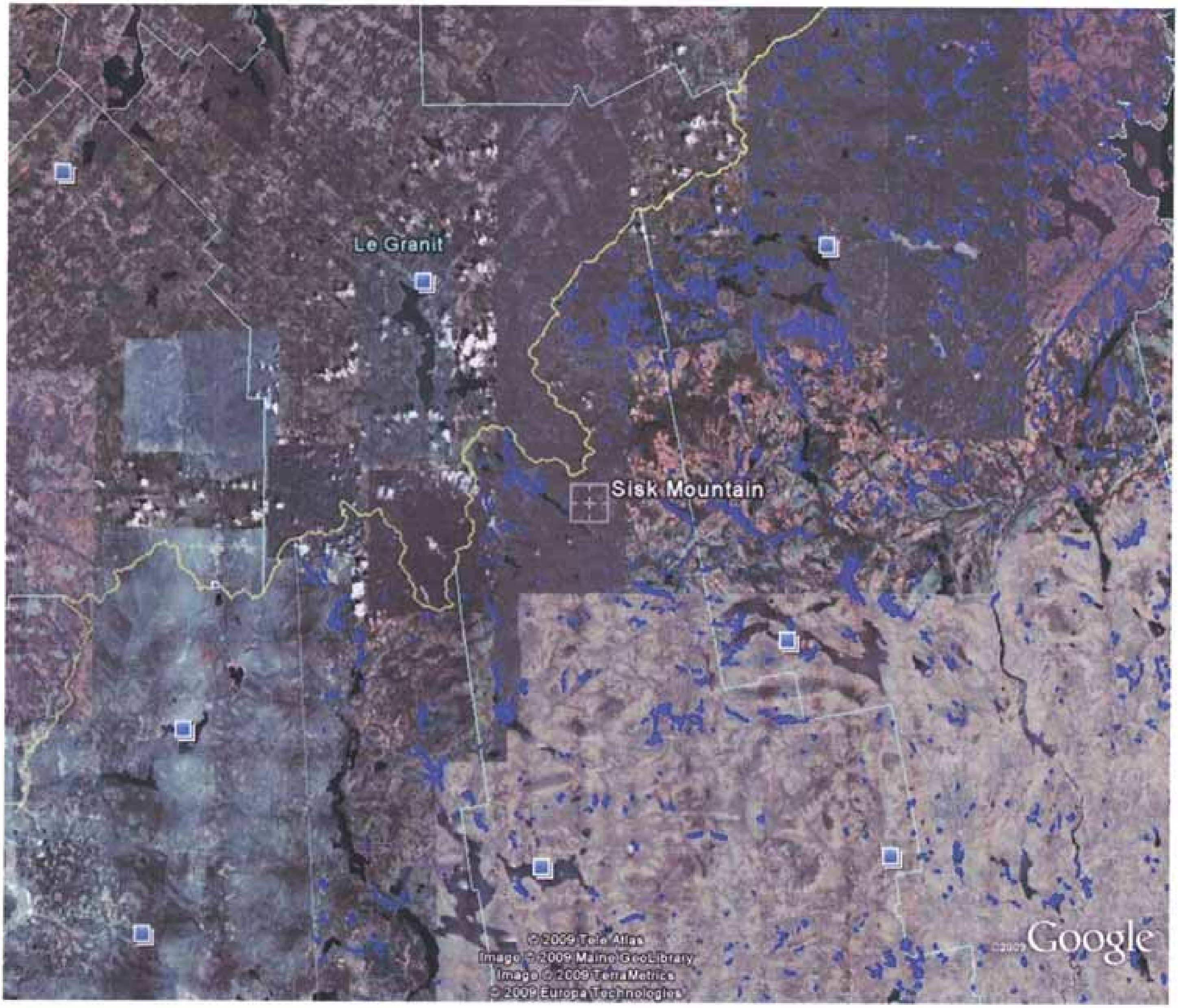
Thank you for consulting the Department during the project planning process. Please feel free to contact the Department if you have questions or require additional information.

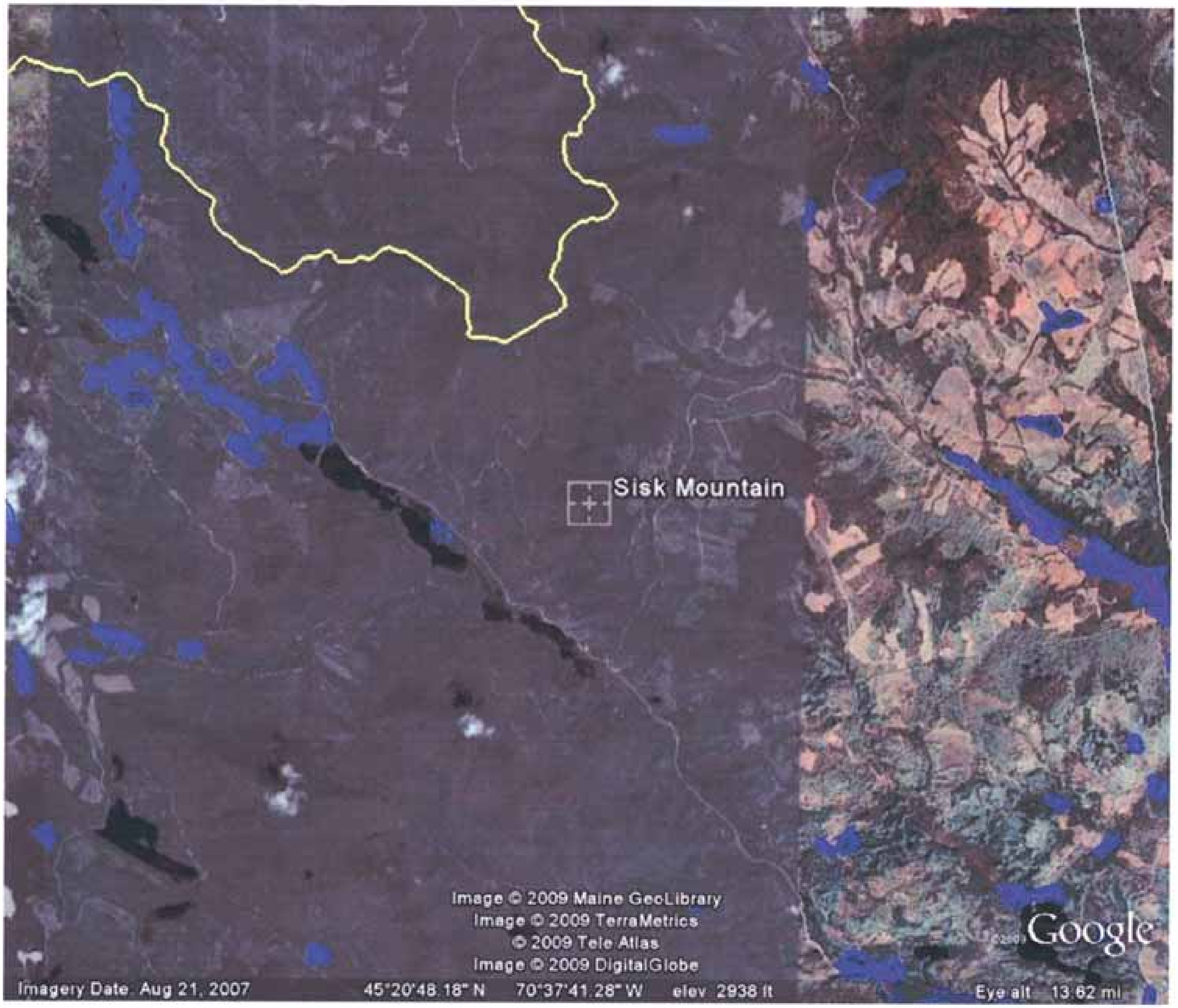
Sincerely,

Becky Maddox

Becky Maddox
Project Manager
Bureau of Land and Water Quality
Division of Land Resource Regulation

Enclosure


Le Granit
Sisk Mountain
© 2009 Tele Atlas
Image © 2009 Maine GeoLibrary
Image © 2009 TerraMetrics
© 2009 Europa Technologies
©2009 Google


Sisk Mountain
Image © 2009 Maine GeoLibrary
Image © 2009 TerraMetrics
© 2009 Tele Atlas
Image © 2009 DigitalGlobe
Google
Imagery Date: Aug 21, 2007
45°20'48.18" N 70°37'41.28" W elev 2938 ft
Eye alt 13.62 mi

SUPPLEMENT S-2

Tracking No.	For office use
Permit No.	

Maine Land Use Regulation Commission
Department of Conservation

Supplement S-2

Requirements for Non-Residential Development

Applicant Name(s): TransCanada Energy Ltd.	Project Location (Township and County): Kibby and Chain of Ponds Townships, Franklin County

TECHNICAL AND FINANCIAL CAPACITY See Attachment S-2A

1. Will you hire any consultants, contractors or staff to design and construct the proposed development? If yes, summarize the previous experience and training of your staff. If no, summarize your own previous experience and training in construction.
2. What is the estimated total cost of the proposed development (including all proposed improvements, structures and facilities)? How will the development be financed (e.g. by the applicant, bank, state government loan, etc.)?

Refer to Section 10.25,C of the Commission's Land Use Districts and Standards for rules relating to technical and financial capacity.

IMPACT ON SERVICES See Attachment S-2A

3. Will your proposed development involve any sources of potential contamination (such as junkyards, auto repair, gas stations, and bulk storage of petroleum)? If so, will the project site be located at least 300 feet from any existing private and public water supplies?
4. If your proposed development will use an existing or new well, where will the well be sited and how will it be constructed to prevent infiltration of surface water and contaminants?
5. Will the project site have electric power? If yes, how will the power be generated (on site, by power company, etc.)? How far is the project site from the nearest existing utility pole?
6. What state-approved dump will you use for the regular collection and disposal of site-generated solid wastes? Provide the name and location of the dump. How will you dispose of construction debris, stumps, brush, wood wastes, asphalt and pavement products?
7. Who will provide fire protection to your project site? Provide the name and distance to the nearest fire station.

VEHICULAR CIRCULATION, ACCESS AND PARKING See Attachment S-2A

8. How will you provide safe, uncongested vehicular access to and circulation within your project area? Will you limit the number and width of entrances and exits onto a roadway to that necessary for safe entering and exiting? Will access be designed so that vehicles can exit the site without backing onto a roadway or shoulder? Will shared access be implemented? If not, describe why shared access is not possible.
9. At what angle will access between the roadway and property intersect the roadway? What curb radius will the access way have? How will sight triangles be designed and maintained on each side of the intersection of the access way and the roadway?

Refer to Section 10.25,D; Section 10.27,D; and Section 10.27,H of the Commission's Land Use Districts and Standards for LURC's traffic management and road construction requirements.

10. If you are proposing to use any existing or new parking areas, explain how such parking will meet the needs of the development and how such parking areas will be designed.
    a. Are you proposing to use on-street or off-street (on-site) parking? If using on-street parking, will parking be parallel or diagonal? If using off-street parking, will parking be located to the side or rear of the principal structure? If not, explain why side or rear parking is not possible.
    b. How will parking areas be visually buffered from the roadway? If your project area is adjacent to residential structures or uses, how will parking areas be visually buffered from such development?
11. If you are proposing to build or upgrade any roads to be used to access your project site, explain how any existing or proposed roadways will meet the needs of the development and describe how such roadways will be designed. Describe what site-specific best management practices will be used to ensure that the roadways will not cause erosion or safety problems.
    a. Provide the following information about each road you propose to build or upgrade:
        - Length and travel width of roadway
        - Right-of-way width
        - Average and maximum sustained grade
        - Number of culverts and/or water crossings
        - Type and depth of wearing surface
        - Type and depth of base
    b. How will the roadways be designed to minimize the use of ditching, cuts and fills. How will the roadways be designed to protect any scenic vistas?
    c. Who will be responsible for continued maintenance of any proposed roadways? If any roadway will be dedicated to a town, plantation, county or other government, will its design comply with that government's roadway construction standards?
    d. If any proposed roadways will be co-utilized for forest management purposes, explain how and where turnouts will be installed to accommodate wood haulers and other large vehicles.

NOISE AND LIGHTING See Attachment S-2A

12. Except for day-time construction activities, will any continuous, regular or frequent source of noise be generated by the development? If yes, describe the source and frequency of such noise and explain how you will ensure that such noise will not exceed LURC's maximum permissible sound pressure levels.
13. If your development will use any new or existing lighting, will all non-essential lighting be turned off after business hours? What will be the hours of operation for your development?

> Refer to Section 10.25,F of the Commission's Land Use Districts and Standards for LURC's noise and lighting requirements.

WATER AND AIR QUALITY See Attachment S-2A

14. If your property or development area is adjacent to any water bodies, what measures will you use to ensure that point and nonpoint sources of water pollutants (including sediment) generated by your development do not affect the surface water quality of the water bodies?
15. How will you ensure that your development will not pose an unreasonable risk of polluting a groundwater aquifer?
16. Will your development generate any air emissions other than ordinary fireplace smoke or heating furnace exhaust? If so, describe the type and amount of emissions.

> Refer to Section 10.25,K; Section 10.25,N; and Section 10.25,O of the Commission's Land Use Districts and Standards for LURC's surface water, groundwater and air quality requirements.

SCENIC CHARACTER, NATURAL AND HISTORIC FEATURES See Attachments S-2A and S-2B

17. How will your development be located, designed and landscaped to minimize visual impacts on the scenic character of the surrounding area? Will structures and other features be visible from existing roadways or shorelines? If on a ridge, how will the natural character of the ridgeline be preserved?
18. If any portion of your project site includes S1 or S2 natural communities or plant species, how will you ensure that there will be no undue adverse impact on the community/species and how will you preserve the values that qualify your site for such designation?
19. If any portion of your project site includes archeologically sensitive areas, structures listed in the National Register of Historic Places or is likely to contain a significant archaeological site or structure, how will you ensure that there will be no undue adverse impact on such features and how will you preserve the values that qualify your project site for such designation?

> Refer to Section 10.25,E of the Commission's Land Use Districts and Standards for LURC's scenic character and natural & historic features requirements.

SHORELAND CRITERIA See Attachment S-2A

20. If your proposed development is adjacent to any lakes or ponds, explain in detail how your proposal is consistent with each of the following shoreland criteria:
    a. The proposal will not adversely affect any significant or outstanding natural and cultural resource values, as identified in the Commission's Wildland Lakes Assessment;
    b. The proposal will not have an undue adverse impact on water quality, alone or in conjunction with other development;
    c. The proposal will not have an undue adverse impact on traditional uses, including non-intensive public recreation, sporting camp operations, timber harvesting, and agriculture;
    d. The proposal will not substantially alter the diversity of lake-related uses available in the area;
    e. Adequate provision has been made to maintain the natural character of shoreland;
    f. The proposal is consistent with the management intent of the affected lakes classification; and
    g. Where future development on a lake may be limited for water quality or other reasons, proposed development on each land ownership does not exceed its proportionate share of total allowable development.

> Refer to Section 10.25,A of the Commission's Land Use Districts and Standards, as well as the "Review Criteria for Shoreland Permits" in the Commission's Comprehensive Land Use Plan (Appendix C, p 4-5) for LURC's standards for shoreland development.

BUILDING LAYOUT IN PROSPECTIVELY ZONED AREAS See Attachment S-2A

21. If your proposed development is located in a D-GN, D-GN2, D-GN3, D-RS or D-RS2 subdistrict within a prospectively zoned area, answer the following questions.
    a. Will your development be substantially similar in building height, bulk, and roof lines to neighboring development? Describe the features that makes your development is substantially similar.
    b. What will you do to facilitate pedestrian access between adjacent sites and nearby residential neighborhoods? What will you do to facilitate automobile access?
    c. Do you propose any windowless walls facing a public road?
    d. If you are proposing new development adjacent to development in a "Main Street" setting (see instructions), will your buildings be configured so that at least 80% of the road frontage to be developed remains devoted to buildings?

> Refer to Section 10.25,B of the Commission's Land Use Districts and Standards for LURC's additional rules for prospectively zoned areas.

All proposals for non-residential development must include Exhibits S-2A, S-2B, and S-2C.

Depending on the nature of your proposal, you may also need to submit some or all of the additional exhibits described below.

> If you are unsure about what to submit with your application, contact the LURC office that serves your area for assistance.

S2-A. FINANCIAL CAPACITY.

To demonstrate that you have adequate financial resources to undertake the proposed development, submit at least one of the following:

- ☐ Submit a letter from a financial institution, government agency or other funding source indicating a commitment to provide a specified amount of funds and the uses for which those funds may be utilized. In cases where there can be no commitment of money until approvals have been received, submit a letter of Intent to Fund from the funding institution indicating the amount of funds and their specified uses.
- ☐ Submit the most recent corporate annual report indicating availability of sufficient funds to finance the development, along with explanatory materials to interpret the report.
- ☐ If you will personally finance the development, submit copies of bank statements or other similar evidence indicating availability of funds necessary to complete the development., including all proposed improvements, structures and facilities.

S2-B. SOLID WASTE DISPOSAL AUTHORIZATION.

To confirm that the solid waste facility you propose for use by your development is available and can accommodate the additional wastes anticipated to be generated by your development, submit a letter of authorization from the owner of the solid waste facility which states both availability and acceptability of the facility to accept wastes from your development. If you have a contract with an individual or firm for the collection and/or transfer of solid wastes from the project area to the approved solid waste facility, provide a signed copy of such contract.

S2-C. SOIL SUITABILITY AND MAPPING.

Submit an on-site soil survey, conducted by a Maine licensed soil scientist according to the "Guidelines for Maine Certified Soil Scientists for Soil Identification and Mapping" (Maine Association of Professional Soil Scientists, 2003). Use a Class A high intensity soil survey to identify soils within all disturbed areas on your project site. Disturbed areas include areas that are stripped, graded, grubbed or otherwise result in soil exposure at any time during the site preparation for, or construction of, a project. Use a Class B soil survey to identify soils elsewhere within the project area.

> In certain cases, LURC may reduce the soil survey class requirements, or waive certain provisions of a Class A or B high intensity soil survey (for instance, the contour mapping requirement). Before you conduct your soil survey, contact the LURC office that serves your area for guidance on how to proceed.

With the results of your soil survey, identify the development potential rating for each soil type within your project area using the Natural Resources Conservation Service's soils potential ratings for low density development. If any soils within your project area have a low or very low development potential rating, explain what measures will be used to overcome the limitations that resulted in such a rating.

S2-D. CORPORATE GOOD STANDING.

If the owner of the proposed development is a corporation, submit a certification of good standing from the Maine Secretary of State.

S2-E. WATER SUPPLY.

If you plan to install a well, submit at least one of the following:

- ☐ A letter from a geologist, hydrogeologist or well driller knowledgeable with the area, describing the project area and stating that a sufficient and healthful water supply is likely to be available.
- ☐ A test well dug or drilled on site and a report prepared which indicates the volume and potability of water obtained from the well.

Additionally, if you plan to install a central water supply, submit detailed plans for the water supply system in conformance with the Maine Drinking Water Regulations. Such plans must be designed by a Maine Registered Professional Engineer and must show all water supply locations, wells, support facilities and structures, and pipelines. You must also describe proposed methods for continued maintenance of the system.

S2-F. ROADWAY DESIGN AND MAINTENANCE.

If you are proposing to construct or upgrade any roadways, submit a plan (drawn to scale) which shows the location of all proposed roadways, as well as turnarounds, water crossings and turnouts and drainage control measures (such as ditches, water bars, etc.). Identify each roadway by name and include width of roadways, rights of way and travel surfaces. Also submit three drawings, each to scale, illustrating the following:

- □ A typical overhead view of the proposed roadways showing widths of the travel way, shoulders, and rights of way, and the roadway center line.
- □ A typical cross section showing the roadway travel surface, location and materials of original ground surface, depth and type of fill to be used, slopes, drainage ditches and other water control devices, and boundaries of the travel surface, shoulders and rights of way.
- □ A typical profile showing elevations of the roadway and the original ground surface, and the percent slope of the final roadway from the center line of the entire length of the roadway.

If you will dedicate any roadways to a town or plantation, you must also submit a maintenance plan that specifies the proposed roadway construction and design standards that will be used.

S2-G. PARKING LANDSCAPING PLAN.

If your proposed development has a parking area that is more than one acre in size, you must submit a landscaping plan that indicates planting locations, type and maintenance. The plan must include provisions that all parking areas will have landscaped strips along the perimeter, as well as landscaped islands within the parking area. The plan also must include provisions that expanses of parking areas will be broken up with landscaped islands that include shaded trees and shrubs. Contact the LURC office that serves your area for additional details about the requirements for a landscaping plan.

S2-H. TRAFFIC IMPACT STUDY.

If your proposed development has the potential to generate significant amounts of traffic or if safety or capacity concerns exist in the area, you may be required to conduct a traffic impact study of roadways and intersections in the vicinity of your project site. If such information is needed, LURC will contact you during the review of your proposal.

S2-I. ARCHAEOLOGICAL SURVEY.

If any portion of your develoment site includes an archeologically sensitive area or a structure listed in the National Register of Historic Places, or is considered by the Maine Historic Preservation Commission or other pertinent authority as likely to contain a significant archaeological site or structure, you must conduct archaeological surveys or submit information on the structure. If such information is needed, LURC will contact you during the review of your proposal.

S2-J. PHOSPHORUS CONTROL.

If your development creates a disturbed area of one acre or more within the direct watershed of a lake or pond, you must submit a phosphorus impact analysis and control plan using the methods and procedures set forth in the booklet "Phosphorus Control in Lake Watersheds: A Technical Guide to Evaluating New Development" (DEP, 1992). The booklet is available from the Department of Environmental Protection by calling (207) 287-3901. This exhibit must include plans for long term maintenance of any proposed phosphorus control measures, including vegetative buffers, infiltration systems and wet ponds.

ATTACHMENT S-2A:

SUPPLEMENT S-2 NARRATIVE

TABLE OF CONTENTS

1. *Will you hire any consultants, contractors or staff to design and construct the proposed development? If yes, summarize the previous experience and training of your staff. If no, summarize your own previous experience and training in construction.*

TransCanada Maine Wind Development has significant experience in development of infrastructure projects, and will utilize its staff capabilities for this effort. To support the proposed development, TransCanada has retained TRC Engineers, LLC (TRC) to provide environmental licensing support for the siting of the proposed meteorological towers (met towers), and for the larger wind turbine project for which the met towers are intended to collect feasibility and design data. In addition, an accomplished wind analysis consultant will be contracted to supervise the installation of the met towers, and collect and interpret the measured wind data. Installation will be contracted to an experienced firm that is familiar with the installation requirements of the proposed equipment. A brief qualifications summary is provided below for TransCanada and TRC.

TransCanada Maine Wind Development Inc.

TransCanada Maine Wind Development Inc. (TransCanada) is a wholly owned subsidiary of TransCanada Corporation, a leader in the responsible development and reliable operation of North American energy infrastructure. TransCanada's approximately 3,550 employees provide industry-leading expertise in pipeline and power operations, and have the project management skills, industry experience, financial resources, and proven track record that are required to successfully develop the Sisk met tower proposal.

TransCanada focuses on electric power services and natural gas transmission, with employees who are expert in these businesses. TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure. Our network of more than 59,000 kilometres (36,500 miles) of pipeline taps into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with approximately 370 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns, controls or is developing approximately 10,900 megawatts of power generation. With a proven track record in developing and operating large infrastructure projects, TransCanada has demonstrated an understanding of the range of technical analyses important to demonstrating project acceptability.

TransCanada has extensive experience in developing wind projects in North America, including many installations of met towers. The development and implementation of the Kibby Wind Power Project is likely the best example of TransCanada's development expertise and commitments to stakeholder relations and responsible development practices. Given our recent success in developing an approved wind project in the same vicinity of the Sisk proposal we anticipate having the necessary background knowledge to proceed with this undertaking. Other specific wind project experience includes the development of six wind farms (totaling 739.5 MW) through 2012 in the Province of Quebec with our partner, Innergex.

TRC Engineers, LLC

TRC is a national leader in environmental permitting, engineering and compliance services for energy companies and projects. In the last ten years, TRC staff has successfully permitted over 40,000 MW of electric generation nationwide covering a wide variety of technologies, including wind power. Presently TRC is providing site selection and environmental permitting assistance for wind power projects in locations across the U.S. Furthermore, TRC provided these services on the recently permitted Kibby Wind Power Project in northwestern Maine. In addition to providing the full range of environmental services to support such projects, TRC frequently provides electrical interconnection support (including design and construction) through its office in Augusta, Maine.

TRC has extensive experience in New England and throughout the Northeast. TRC has over 25 years experience working within all aspects of environmental regulations in Maine, including environmental licensing work on the Maritimes & Northeast Pipeline Project and the Bangor Hydro-Electric Company 345 Kilovolt Transmission Line Project. TRC has offices located in Augusta, Portland, and Ellsworth, Maine. Staff from these offices will be among those supporting this project. Their presence and experience working in Maine, and their involvement in the Kibby Wind Power Project will provide important insights and expertise to the Sisk Mountain Wind Power Project.

2. *What is the estimated total cost of the proposed development (including all proposed improvements, structures and facilities)? How will the development be financed (e.g., by the applicant, bank, state government loan, etc.)?*

The estimated total cost for installation of met towers on Sisk Mountain (and associated access and geotechnical work) is $500,000 USD.

The project will be financed in its entirety by TransCanada, utilizing internal sources of financing. The 2008 audited annual report of TransCanada Corporation is provided in Exhibit S2-A. During 2008, TransCanada had net income of $1.44 billion, cash flow from continuing operations of $2.84 billion, and an asset base of $39.4 billion.

3. *Will your proposed development involve any sources of potential contamination (such as junkyards, auto repair, gas stations, and bulk storage of petroleum)? If so, will the project site be located at least 300 feet from any existing private and public water supplies?*

During construction, small quantities of fuel will be utilized in construction vehicles and equipment. Once the met towers are installed and operational, no significant quantities of potential contamination sources will be utilized at the site. In any event, each site is significantly greater than 300 feet from existing private and public water supplies.

4. *If your proposed development will use an existing or new well, where will the well be sited and how will it be constructed to prevent infiltration of surface water and contaminants?*

The proposed activity will not involve use of either an existing or new well.

5. *Will the project site have electric power? If yes, how will the power be generated (on site, by power company, etc.)? How far is the project site from the nearest existing utility pole?*

Electric power will not be required for the proposed met towers. Power required for data collection will be supplied by batteries integral to the component design.

6. *What state-approved dump will you use for the regular collection and disposal of site generated solid wastes? Provide the name and location of the dump. How will you dispose of construction debris, stumps, brush, wood wastes, asphalt and pavement products?*

Once installed and operational, no solid waste will be generated by the proposed met towers; however, consultation with the Eustis Town Office indicated that the transfer station located on State Route 16 in the Town of Eustis will accept typical municipal solid waste from Kibby, Skinner and other nearby townships.

Construction debris will consist primarily of wood wastes generated from clearing activity (slash, unmarketable trees and brush). Slash and brush (material less than three inches in diameter) will be used to line steep slopes and other potentially erodable areas within the access trails to help prevent rutting and hold soils in place. The remainder of the slash and brush will be cut up and scattered in the woods adjacent to cleared areas in a manner that avoids large piles of cut slash. Any accumulations of slash will be no taller than 18 inches above the ground and no more than 50 feet long. A minimum of 25 feet of separation will be maintained between any such accumulations. Unmarketable trees and larger limbs (material that is 3 inches or more in diameter) will be cut into approximately 4-foot lengths and be similarly scattered in the woods adjacent to cleared areas. This 4-

foot material will be stacked such that the stack height is no more than 18 inches above ground and no more than 25 feet long, with a minimum of 25 feet of separation between stacks.

The minimal amounts of other waste materials generated during construction (paper and plastic products, short lengths of cable, and domestic waste) will be disposed of at the Eustis Transfer Station.

7. *Who will provide fire protection to your project site? Provide the name and distance to the nearest fire station.*

The nature of the proposed met towers and equipment does not present any significantly increased fire hazard over natural conditions in a forested area such as currently exists at the proposed sites. However, consultation with the Eustis Town Office indicated that the Eustis Fire Department, located on State Route 27 approximately 22 miles from the approximate center of the proposed activity, would respond to a fire in the project area.

8. *How will you provide safe, uncongested vehicular access to and circulation within your project area? Will you limit the number and width of entrances and exits onto a roadway to that necessary for safe entering and exiting? Will access be designed so that vehicles can exit the site without backing up onto a roadway or shoulder? Will shared access be implemented? If not, describe why shared access is not possible.*

New roads will not be constructed as a result of the proposed met towers.

The met tower access trail will be reached using the existing Plum Creek logging roads, as shown in Exhibit A of the general Permit Application. From those existing roads, additional clearing will be required to accommodate a tracked vehicle or skidder that will transport the met towers and installation equipment and for an excavator/backhoe that will be needed to install ground anchors.

As discussed in detail in Attachment B of the general Permit Application, the location of these proposed cleared trails will utilize existing trails to the extent possible. New clearing has been substantially limited by locating the access trails in such locations and by minimizing the proposed clearing to that necessary to accommodate the construction equipment. Following installation, the construction access trails will be utilized by ATV, snowmobile and foot travelers for equipment operations and maintenance, but the trails will be maintained only to a 4-foot width.

9. *At what angle will access between the roadway and property intersect the roadway? What curb radius will the access way have? How will sight triangles be designed and maintained on each side of the intersection of the access way and the roadway?*

No new roadways will be constructed onto public ways. As noted above, access will be via trails extending from existing private logging roads. TransCanada will coordinate closely with Plum Creek and Kennebec West to ensure that, during construction, the logistics of entering and exiting those private road systems can be safely undertaken.

10. *If you are proposing to use any existing or new parking areas, explain how such parking will meet the needs of the development and how such parking areas will be designed.*

No parking areas will be associated with the proposed met towers. The limited construction parking required will occur in the vicinity of the proposed access trails and will be coordinated with Plum Creek and Kennebec West to ensure it will not interfere with ongoing operations.

11. *If you are proposing to build or upgrade any roads to be used to access your project site, explain how any existing or proposed roadways will meet the needs of the development and describe how such roadways will be designed. Describe what site-specific best management practices will be used to ensure that the roadways will not cause erosion or safety problems.*

No roads are proposed to be built or upgraded for the proposed met tower installation or use, as discussed above.

12. *Except for day-time construction activities, will any continuous, regular or frequent source of noise be generated by the development? If yes, describe the source and frequency of such noise and explain how you will ensure that such noise will not exceed LURC's maximum permissible sound pressure levels.*

Construction related to installation of the met towers will occur only during day-time hours. Once the towers are installed, the only sound generated would be the extremely quiet sounds associated with turning of the anemometers. This small level of additional sound, primarily when increased natural wind speeds would provide a higher background sound level, is not anticipated to exceed the Land Use Regulation Commission's (LURC) maximum permissible sound pressure levels, particularly given the size of the Plum Creek property within which the installations will be located.

13. *If your development will use any new or existing lighting, will all non-essential lighting be turned off after business hours? What will be the hours of operation for your development?*

No lighting is necessary for these structures.

14. *If your property or development area is adjacent to any water bodies, what measures will you use to ensure that point and nonpoint sources of water pollutants (including sediments) generated by your development do not affect the surface water quality of the water bodies?*

The sites of the proposed met towers are not adjacent to water bodies. No lakes or ponds are located in the project vicinity. Proposed access trails also avoid proximity to streams and/or wetlands to the greatest extent possible. One stream crossing will be required; this is located on an existing winter road and will require the replacement of a culvert that was removed. This may incur some limited temporary wetland impacts in wetlands associated with the stream crossing. Wetland issues are addressed in Supplement S-3. Proposed measures to ensure that surface water quality is not affected by sedimentation and erosion are addressed in Exhibit H of the general Permit Application.

15. *How will you ensure that your development will not pose an unreasonable risk of polluting a groundwater aquifer?*

The proposed activities do not involve subsurface work, other than excavation of 4-foot deep holes to install ground anchors, nor do they involve the storage of materials in substantial quantities with the potential to pollute a groundwater aquifer. *Significant Sand and Gravel Aquifer Maps* published by the Maine Geological Survey were reviewed to identify any known significant sand and gravel aquifers in the project vicinity. Based on available mapping, the nearest aquifer is along the North Branch of the Dead River (along Route 27) approximately 5 miles southwest of Sisk Mountain.

16. *Will your development generate any air emissions other than ordinary fireplace smoke or heating furnace exhaust? If so, describe the type and amount of emissions.*

No air emissions will be generated by the proposed met tower installation. In fact, the met towers are intended to collect data for continuing feasibility assessment for a proposed wind turbine installation that, if constructed, would generate electricity without resultant air emissions.

17. *How will your development be located, designed and landscaped to minimize visual impacts on the scenic character of the surrounding area? Will structures and other features be visible from existing roadways or shorelines? If on a ridge, how will the natural character of the ridgeline be preserved?*

A discussion regarding potential visual impacts and scenic character is provided in Attachment S-2B.

18. *If any portion of your project site includes S1 or S2 natural communities or plant species, how will you ensure that there will be no undue adverse impact on the community/species and how will you preserve the values that qualify your site for such designation?*

Correspondence has been sent to the Maine Natural Areas Program requesting known mapped resource information; a copy of this correspondence and their response is provided in Attachment C, Appendix A of the general Permit Application.

Correspondence has also been sent to the Maine Department of Inland Fisheries and Wildlife (MDIFW), the Maine Department of Environmental Protection (MDEP) and United States Fish and Wildlife Service (USFWS) requesting information about known species occurrence in the project vicinity. A copy of each agency's response is provided in Attachment C, Appendix A of the general Permit Application.

19. *If any portion of your project site includes archaeologically sensitive areas, structures listed in the National Register of Historic Places or is likely to contain a significant archaeological site or structure, how will you ensure that there will be no undue adverse impact on such features and how will you preserve the values that qualify your project site for such designation?*

The proposed work is not located within an archaeologically sensitive area, near a structure listed in the National Register of Historic Places or likely to contain a significant archaeological site or structure.

A Phase 0 survey for PreContact period archaeological sites was previously conducted in this area in 1993 for U.S. Windpower's proposed New England Wind Energy Station (Will 1993, Maine Historic Preservation Commission [MHPC] report #2757). No archaeological sites were reported in the vicinity of that project area, and field reconnaissance indicated that the area had low archaeological sensitivity for PreContact period sites. MHPC site files for the Kibby Wind Power Project were reexamined on August 12, 2005 to ascertain whether any new archaeological site data had been gathered from the area. No additional information was uncovered. The Sisk Wind Power Project largely overlaps with a portion of the U.S. Windpower project proposed more than a decade ago. No further archaeological evaluation is anticipated to be required for the new project. A letter requesting review for the Sisk Wind Power Project was sent to the Maine Historic Preservation Commission. A copy of the letter is provided at the end of this attachment.

Shoreland Criteria

20. *If your proposed development is adjacent to any lakes or ponds, explain in detail how your proposal is consistent with each shoreland criteria.*

The proposed activity is not adjacent to a lake or pond; thus, the shoreland criteria are not applicable.

Building Layout in Prospectively Zoned Areas

21. *If your proposed development is located in a D-GN, D-GN2, D-GN3, D-RS or D-RS2 subdistrict within a prospectively zoned area, answer the following questions.*

The proposed activity is not located in any of the above zoning subdistricts; therefore the related questions are not applicable.

TRC
249 Western Avenue
Augusta, ME 04330

207.621.7000 PHONE
207.621.7001 FAX

www.TRCsolutions.com

March 12, 2009

Dr. Arthur Speiss
Maine Historic Preservation Commission
55 Capital Street
State House Station 65
Augusta, ME 04333

Subject: **Request for Review - Sisk Wind Power Project**

Dear Dr. Speiss:

This letter is to request your review of the proposed Sisk Mountain Wind Project to determine the need for any additional historic or archaeological investigations. The project is located in Kibby and Chain of Ponds Townships, in Franklin County, Maine. This site is immediately adjacent (to the west) to the Kibby Wind Power Project.

Sisk Mountain is currently under evaluation for development of a wind power facility. As shown on the attached map, four locations have been proposed for installation of meteorological towers (met towers) which will gather information necessary to determine the suitability of Sisk Mountain for wind tower development. Installation and operation of this equipment will not require the construction of any new roads or unvegetated surfaces. Limited clearing will be required for proper installation of the met towers and operation of associated equipment, and to create access trails to the sites. Existing logging roads, skidder paths and trails will be used as much as possible to minimize need for new trails. Existing and new trails will also be used for geotechnical investigations, which area also part of the current proposal. The attached Figure illustrates the locations of the four proposed met towers and associated access.

A Phase 0 survey for PreContact period archaeological sites was previously conducted in this area in 1993 for the then-proposed New England Wind Energy Station (also known as Kenetech or U.S. Windpower Project) by Richard Will, PhD (MHPC report #2757). No archaeological sites were reported in the vicinity of that project area and field reconnaissance indicated that the area had low archaeological sensitivity for PreContact period sites. Site files for the Kibby Wind Power Project were re-examined by Dr. Richard Will on August 12, 2005 to determine whether any new archaeological site data had been gathered from the area; no additional information was gathered at that time.

We believe, given prior review, that no further studies are warranted for historical or archaeological resources in the area of the Sisk Wind Power Project. We would appreciate your review of this information to confirm this assumption or to direct us with regard to potential issues requiring further study.

The information you provide will be incorporated into a permit application to the Maine Land Use Regulation Commission (LURC) for installation of the met towers and geotechnical investigations. TRC is also contacting other appropriate state and federal agencies with appropriate requests for information related to the LURC met tower application.

Please me at TRC (207)-621-7093 or dvalleau@trcsolutions.com with any questions you may have. I look forward to your reply within approximately two weeks, if possible. Thank you for your time.

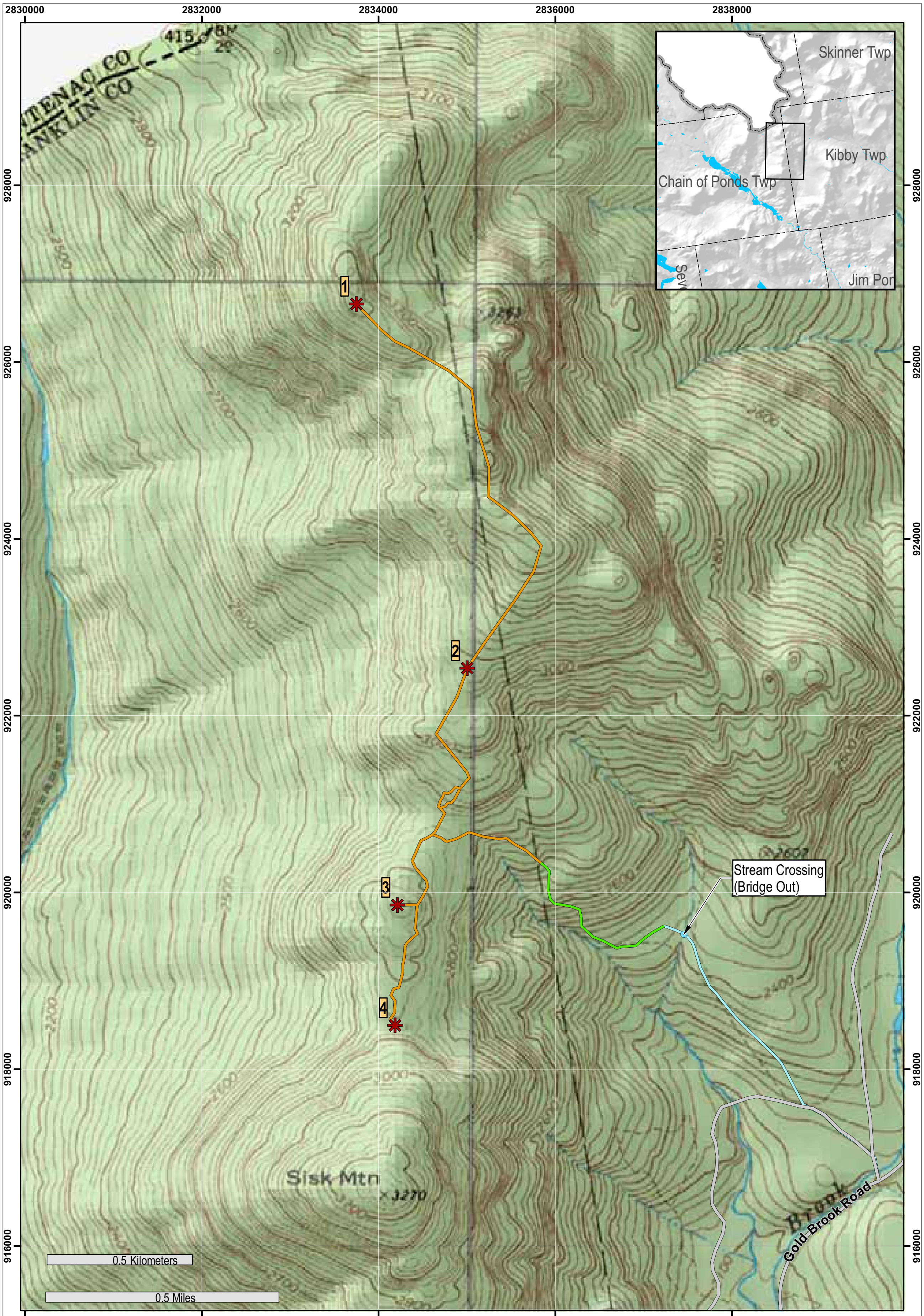
Sincerely,

Dana Valleau

Dana Valleau
Environmental Scientist

Enclosure

Cc: Christine Cinnamon, TransCanada Energy, Ltd.



N

- Potential Met Sites
- Stream
- Maintained Road
- Existing Winter Road
- Existing Skid Trail
- Potential Access Trail

Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

Sisk Mountain
Proposed Meteorological Tower
Sites and Access

EXHIBIT: A-1

249 Western Ave
Augusta, ME 04330

TRC

Created:
2/6/2009

ATTACHMENT S-2B:

SCENIC CHARACTER, NATURAL AND HISTORIC PLACES

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LIST OF FIGURES

1.0 Introduction

The purpose of the following discussion is to address questions and considerations posed in the Land Use Regulation Commission (LURC) S-2 form, and Chapter 10 (Section 10.25(E)(1)) of LURC's Land Use District Rules and Standards. These items pertain to the potential impact of the proposed development on scenic, natural and historic features. Sections 2.0 and 3.0, below, address each item as it appears in its respective document.

2.0 Scenic Character

The LURC S-2 Supplement Application form and Chapter 10 (Section 10.25(E)(1)) of LURC's Land Use District Rules and Standards request the following considerations with regard to scenic character. A discussion addressing these items follows.

LURC Form S-2, Question 17:

17. How will your development be located, designed and landscaped to minimize visual impacts on the scenic character of the surrounding area? Will structures and other features be visible from existing roadways or shorelines? If on a ridge, how will the natural character of the ridgeline be preserved?

Land Use District Rules and Standards: Chapter 10, Section 10.25 E(1)

E(1)(a): The design of proposed development shall take into account the scenic character of the surrounding area. Structures shall be located, designed and landscaped to reasonably minimize their visual impact on the surrounding area, particularly when viewed from existing roadways or shorelines.

E(1)(b): To the extent practicable, proposed structures and other visually intrusive development shall be placed in locations least likely to block or interrupt scenic views as seen from traveled ways, water bodies, or public property.

E(1)(c): If a site includes a ridge elevated above surrounding areas, the design of the development shall preserve the natural character of the ridgeline.

The scale of the landscape surrounding the project area is very large. The mountains rise over a thousand feet above the valley floor, and the peaks are generally miles apart. The project area vista includes numerous nearby clearcuts (ranging in size from several dozen acres to several hundred acres), logging roads, gravel pits, staging areas, and other traces of commercial timber harvesting. The surrounding area also includes Kibby Mountain and Kibby Range, which are currently being developed for wind power generation; as such, the surrounding vista already includes similar met tower installations on nearby ridgelines. A portion of the proposed project occurs within the LURC's Expedited Wind Power Project Permitting Area (See Figure S-2B-1).

Existing access trails will be used to a significant extent for construction; for this reason, visual change associated with structure access will be extremely limited. At the met tower sites, a maximum area of approximately 1.09 acres will be cleared, leaving low herbaceous ground cover in place. This area includes one or more linear corridors which radiate from a central clearing to accommodate installation and anchoring of the met tower guy wires. Within the approximate center of the clearing, the met tower itself will be installed. Cleared areas on the ridge of Sisk Mountain will retain native vegetative ground cover and are not expected to create a visual contrast to remaining vegetation. Clearing for access will be isolated and linear; clearing at met tower installation sites will be isolated to each met tower, and sites will be widespread. Cleared areas as a result of met tower construction and maintenance are not expected to be visible from any public vantage.

The proposed met towers will be light in color and will have a thin profile. The proposed met towers are a 16-inch-square lattice structure (as shown in Figure S-2B-2) or a steel tubular structure (as shown in Figure S-2B-3), 197 feet in height. Trees on the ridgeline are estimated to be approximately 30 to 50 feet in height; as such, the proposed 197-foot met towers will be visible above the treeline. The resulting effect is that the proposed met towers will add new linear elements (in addition to existing trees which provide numerous linear features) to the landscape in four isolated locations along the ridge.

Each met tower is distributed widely, not clustered or grouped tightly such that a massing of structures would increase their visibility. Each individual location will present a slim, light-colored profile that will most likely be perceived as a subordinate element of the larger landscape and will not be a major visual intrusion.

The light color and slender profile of the met towers reduces their visibility from a distance and will minimize their intrusion on existing views. The contrast of met tower forms to existing landscape will be minimized by the isolated nature of each met tower and by retaining as much vegetation as possible. At distances greater than 1 mile, it is anticipated that they will barely be visible against the sky and will minimally be visible against a backdrop of trees. Public viewing opportunities that may be available from traveled ways, water bodies or public property are generally greater than 1 mile away from the met towers.

3.0 Natural Features

The LURC S-2 Supplement Application form and Chapter 10 (Section 10.25(E)(1)) of LURC's Land Use District Rules and Standards request the following considerations with regard to natural features. A discussion addressing these items follows.

<u>LURC Form S-2, Question 18:</u>

18. If any portion of your project site includes S1 or S2 natural communities or plant species, how will you ensure that there will be no undue adverse impact on the community/species and how will you preserve the values that qualify your site for such designation?

<u>Land Use District Rules and Standards: Chapter 10, Section 10.25 E(2)</u>

E(2)(a). If any portion of a subdivision or commercial, industrial or other nonresidential project site includes critically imperiled (S1) or imperiled (S2) natural communities or plant species, the applicant shall demonstrate that there will be no undue adverse impact on the community and species the site supports and indicate appropriate measures for the preservation of the values that qualify the site for such designation.

A request for information regarding S1 and S2 communities was sent to the Maine Department of Conservation's Maine Natural Areas Program (MNAP) as part of the Natural Resources Assessment. Similar requests were also sent to the Maine Department of Inland Fisheries and Wildlife (MDIF&W), the U.S. Fish and Wildlife Service (USFWS) and the Maine Department of Environmental Protection (MDEP). In its reply, MNAP identified two S1 or S2 plant species occurrences located on Sisk Mountain (see Attachment C of the general permit application); the proposed project will not encroach on these known occurrences. For greater detail, see Attachment C – Natural Resources Assessment of the general application.

4.0 Historic Features

The LURC S-2 Supplement Application form and Chapter 10 (Section 10.25(E)(1)) of LURC's Land Use District Rules and Standards request the following considerations with regard to historic features. A discussion addressing these items follows.

<u>LURC Form S-2, Question 19:</u>

19. If any portion of your project site includes archeologically sensitive areas, structures listed in the National Register of Historic Places or is likely to contain a significant archaeological site or structure, how will you ensure that there will be no undue adverse impact on such features and how will you preserve the values that qualify your project site for such designation?

<u>Land Use District Rules and Standards: Chapter 10, Section 10.25 E(2)</u>

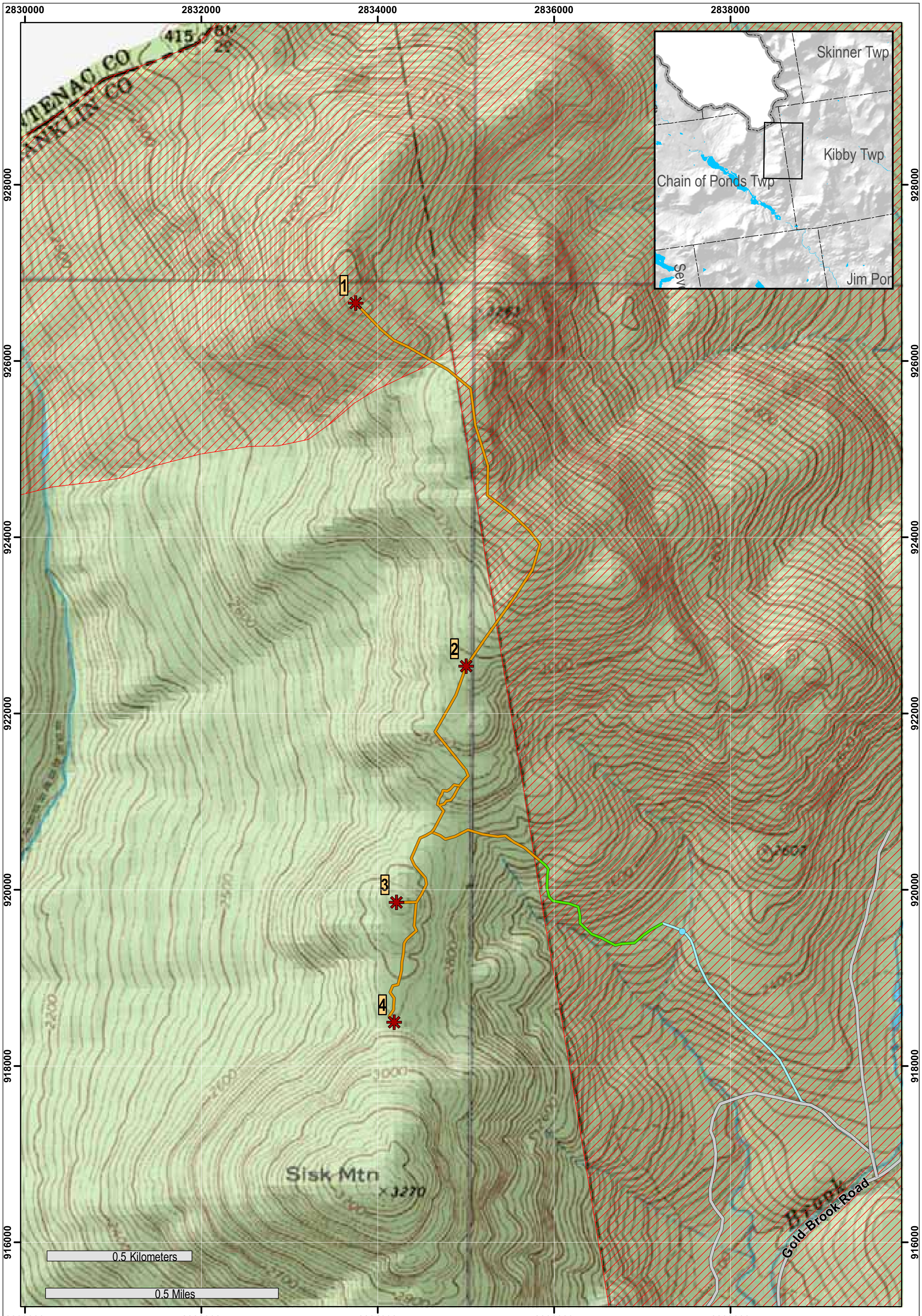
E(2)(b). Historic Features. If any portion of a subdivision or commercial, industrial or other nonresidential project site includes an archaeologically

> *sensitive area or a structure listed in the National Register of Historic Places, or is considered by the Maine Historic Preservation Commission or other pertinent authority as likely to contain a significant archaeological site or structure, the applicant shall conduct archaeological surveys or submit information on the structure, as requested by the appropriate authority. If a significant archaeological site or structure is located in the project area, the applicant shall demonstrate that there will be no undue adverse impact to the archaeological site or structure, either by project design, physical or legal protection, or by appropriate archaeological excavation or mitigation.*

A search of the National Register of Historic Places database identified 42 resources in Franklin County. Among registered resources is the Arnold Trail. The Arnold Trail runs along the Kennebec River through Wyman Lake and along the Dead River through Flagstaff Lake and Chain of Ponds to the Quebec border in Coburn Gore. Portions of the trail that run through the Chain of Ponds Township traverse between the Chain of Ponds and the toe of Sisk Mountain's southern slope, following State Route 27. Potential views of the project from the Arnold Trail are limited by intervening topography, such as the high southern ridges of Sisk Mountain, the winding nature of the road, and tree cover along Route 27.

The next closest registered resources are located in Stratton, approximately 15 miles southeast of Sisk Mountain, and in Rangeley, Dallas Plantation and Madrid Township, approximately 20 miles to the south. All other listed resources are over 30 miles to the south of Sisk Mountain. The proposed met towers will not be visible from these resources.

There are no known archaeological sites that will be impacted by the proposed project.



N

- Potential Met Tower Sites
- Stream Crossing
- Maintained Road
- Existing Winter Road
- Existing Skid Trail
- Potential New Access Trail
- Expedited Windpower Project Permitting Area

Sisk Mountain
Proposed Project Location and
LURC Expedited Windpower
Project Permitting Area

FIGURE: S-2B-1

249 Western Ave
Augusta, ME 04330

TRC

Created:
3/10/2009

Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

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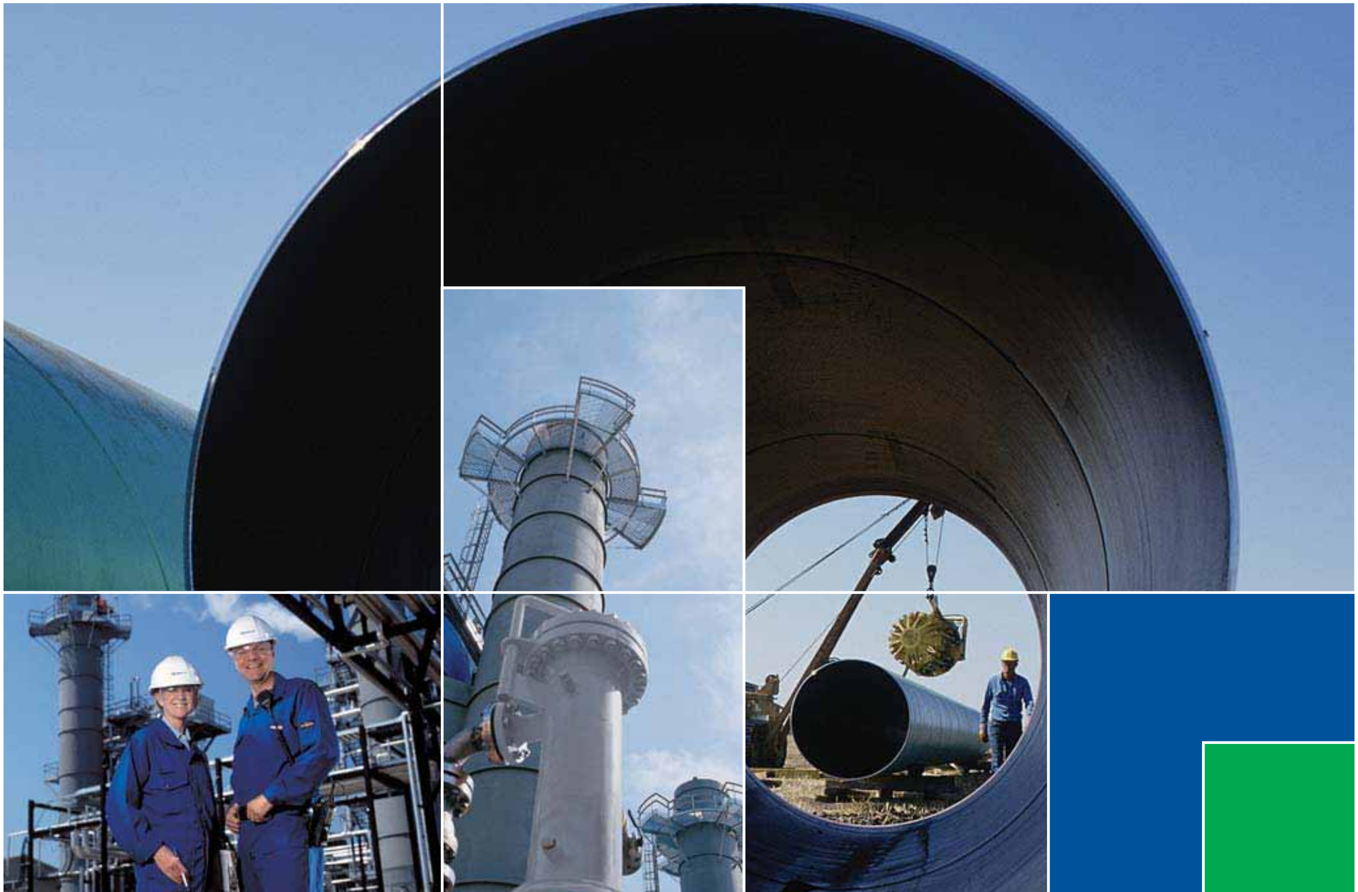
Figure S-2B-2: Photo of Lattice Style Met Tower

Figure S-2B-3: Photo of Tubular Style Met Tower

EXHIBIT S-2-A:

FINANCING SUPPORT



2008

annual report

celebrating yesterday

delivering today

building for tomorrow

TransCanada
In business to deliver

celebrating yesterday

It was a true engineering wonder of its time. Nearly 3,700 kilometres of steel pipe – pushed through some of the toughest terrain in Canada.

Up to 5,000 workers persevered through a multitude of obstacles, often under extremely adverse conditions, to build what would be the world's longest pipeline.

In 2008, TransCanada's Canadian Mainline celebrated 50 years of history – recognizing a milestone anniversary of the final weld on the first pipeline system designed to deliver Alberta natural gas to markets in Ontario and Quebec.

Construction of the Mainline's western leg began on June 17, 1956 at Burstall, Saskatchewan. Natural gas reached the cities of Winnipeg, Manitoba and Regina, Saskatchewan on the Canadian Prairies in September 1957. Workers pushed on, challenged by the terrain and the remoteness of the land - moving about one kilometre a day across Ontario and, finally into Quebec.

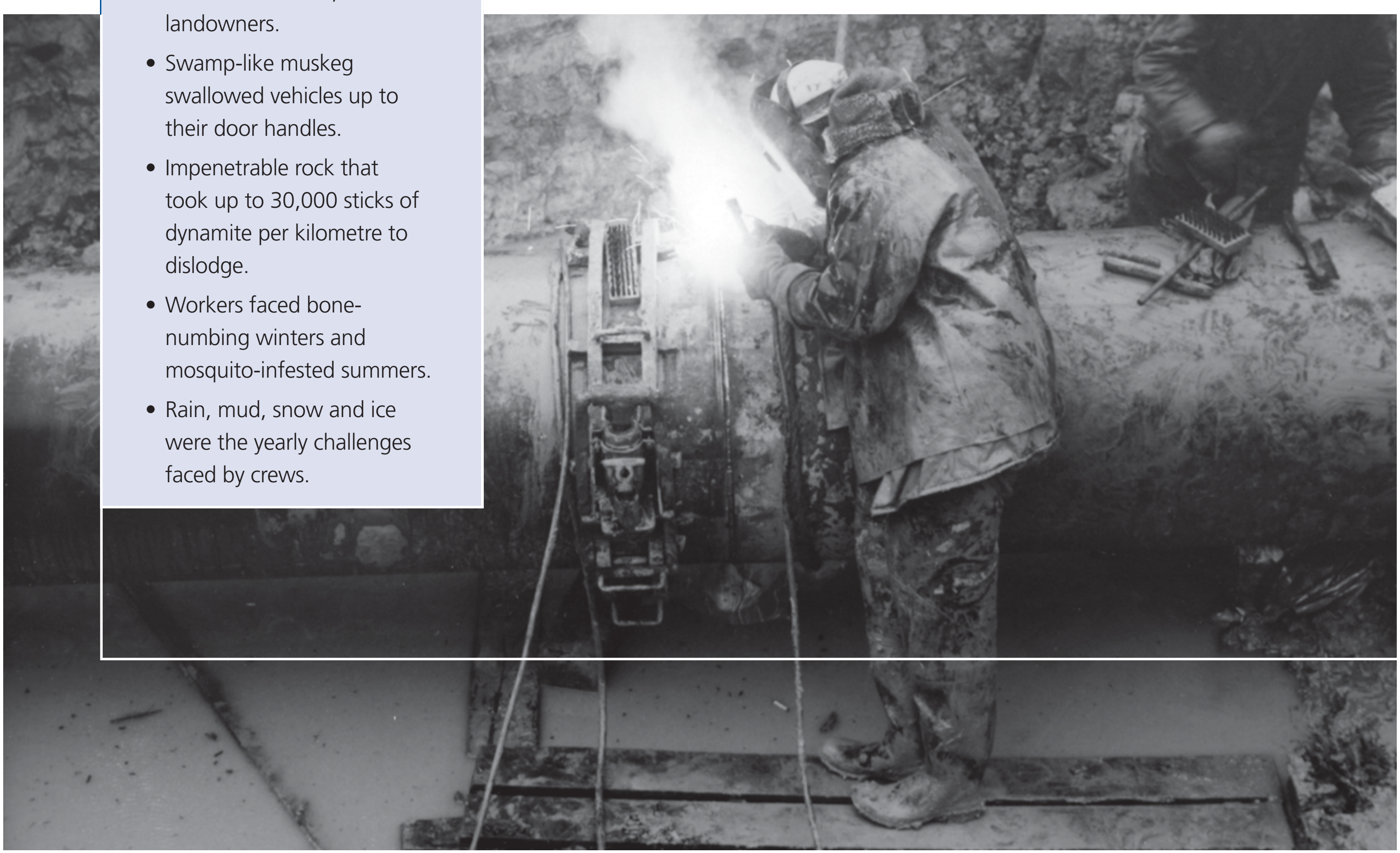
The final weld on the pipeline took place in Kapuskasing, Ontario on October 10, 1958.

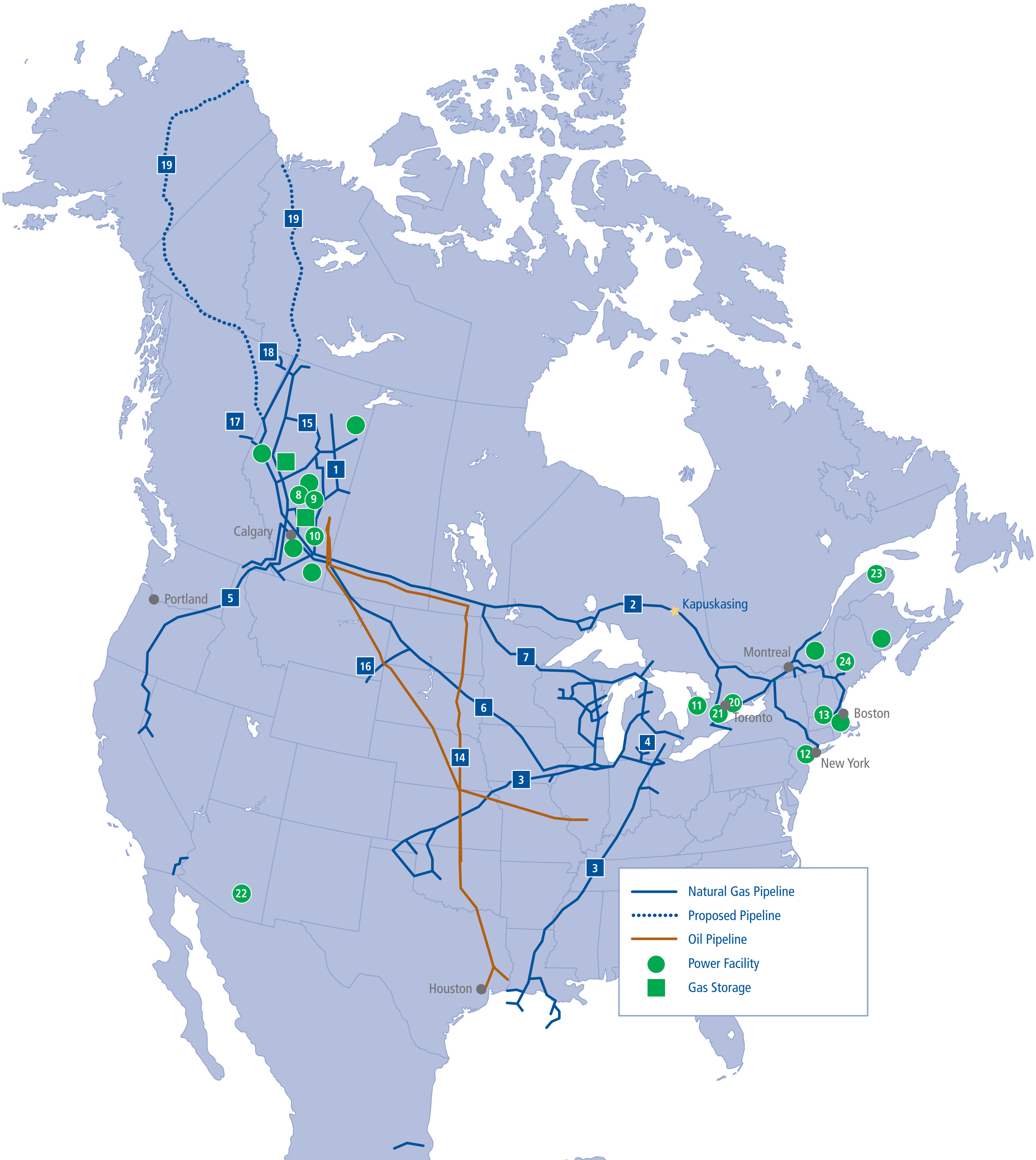
To commemorate the event, Canada Post and TransCanada unveiled a special edition Canadian postage stamp, depicting a single, anonymous welder representing thousands of labourers who worked to complete the historic pipeline.

A little known fact – a silver dollar was welded to the pipe in that location. That silver dollar is now on display at TransCanada's head office in Calgary, Alberta.

Canadian Mainline Construction Facts

- $375 million original cost.
- 655,000 tons of pipe carried by 25,000 railway cars.
- 184 lakes and rivers crossed.
- Permission needed from more than 5,000 landowners.
- Swamp-like muskeg swallowed vehicles up to their door handles.
- Impenetrable rock that took up to 30,000 sticks of dynamite per kilometre to dislodge.
- Workers faced bone-numbing winters and mosquito-infested summers.
- Rain, mud, snow and ice were the yearly challenges faced by crews.

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New York
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Houston
Natural Gas Pipeline
Proposed Pipeline
Oil Pipeline
Power Facility
Gas Storage

Pipelines

TransCanada operates one of the largest natural gas pipeline systems in North America. With 50 years of experience, we are experts in the business of operating, maintaining and building large-diameter, long-haul pipelines. The strength of our pipeline business is rooted in these examples of critical infrastructure:

Delivering 20% of the natural gas consumed in North America

1 Alberta System This 23,705 kilometre (14,730 mile) pipeline moves approximately 11 Bcf/d, making it one of the largest in North America. It gathers natural gas for use in Alberta and delivers it to provincial border points for export to North American markets. In 2008, the Alberta System gathered 66 per cent of the natural gas produced in Western Canada.

2 Canadian Mainline This 14,101 kilometre (8,762 mile) pipeline extends east from the Alberta border to Quebec and connects with other natural gas pipelines in Canada and the United States. Across the Canadian prairies, the system consists of five parallel lines capable of transporting approximately 7.0 Bcf/d.

3 ANR Pipeline System **4** ANR Storage This 17,000 kilometre (10,563 mile) pipeline has a peak day capacity of 6.8 Bcf/d. It delivers natural gas from producing fields in Texas, Oklahoma, Louisiana and the Gulf of Mexico to markets in Wisconsin, Michigan, Illinois, Ohio and Indiana. ANR also owns and operates 250 Bcf of regulated natural gas storage capacity in Michigan.

5 GTN **6** Northern Border **7** Great Lakes These three natural gas pipelines include a total of 7,828 kilometres (4,864 miles) of pipe and deliver natural gas from Western Canada to premium markets across North America.

Energy

TransCanada has built a successful power business by acquiring low-cost, baseload generation, and developing new large-scale facilities backed by long-term power purchase arrangements. Today we own or have interests in 19 power plants in Canada and the United States. We also have a significant non-regulated natural gas storage business in Alberta where we own or have the rights to 120 Bcf of capacity. Some examples of our Energy assets include:

Capacity to power 11 million homes

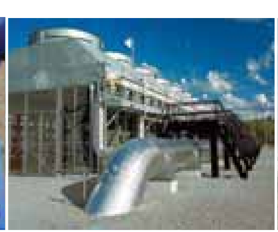
8 **9** Sundance **10** Sheerness Through these power purchase arrangements in Alberta and a number of other wholly-owned plants, we market 20 per cent of the province's power.

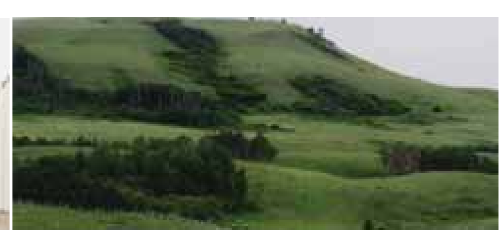
11 Bruce Power Canada's first private nuclear generating station, this facility currently produces 4,700 MW of power or more than 20 per cent of Ontario's electricity.

12 Ravenswood Generating Station Located in Queens, New York, the 2,480 MW power plant is capable of supplying 20 per cent of New York City's power needs.

13 TC Hydro 13 hydroelectric facilities on the Connecticut and Deerfield rivers in New Hampshire, Vermont and Massachusetts produce 583 MW of power.







delivering today

TransCanada is a leading North American energy infrastructure company.

With approximately $40 billion in assets, today we are a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and natural gas storage facilities.

$40 billion in assets

Our 59,000 kilometre (36,661 mile) wholly-owned natural gas pipeline network taps into virtually every major natural gas supply basin on the continent and provides our customers with unparalleled access to premium markets. Each day we deliver 20 per cent of the natural gas consumed in North America. Looking forward, our vast pipeline network is well positioned to connect new sources of supply such as shale gas, coalbed methane and offshore liquefied natural gas as well as supply from the north.

We are also one of the continent's largest providers of natural gas storage and related services with approximately 370 billion cubic feet of capacity – enough to meet the needs of nearly four million homes each year.

4,000 talented employees

As one of Canada's largest independent power producers, TransCanada owns, controls or is developing more than 10,900 megawatts of power generation in Canada and the United States – enough capacity to power 11 million homes. Our diversified power portfolio includes natural gas, nuclear, coal, hydro and wind generation primarily located in Alberta, Ontario, Quebec and the northeastern United States.

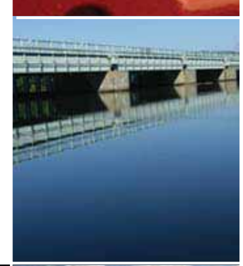
Recently, we made a significant entry into the oil pipeline business through the Keystone Pipeline System. When completed it will be one of North America's largest oil delivery systems with the capacity to move 1.1 million barrels per day from Western Canada to markets in the U.S. Midwest and Gulf Coast.

Going forward, we will continue to create value for our shareholders and our customers by building and operating the energy infrastructure that North America needs.

Today, we are in the midst of an $18 billion capital program that will see a number of attractive, low-risk projects completed over the next four years. They include expansions of our existing pipeline infrastructure, new pipeline infrastructure, new natural gas storage facilities and new power plants – critical infrastructure in the markets we serve.

Creating value for our shareholders and customers

As we build for tomorrow, TransCanada is committed to being a reliable and safe operator, with a focus on providing low-cost, competitive services to our customers.



With growth comes greater responsibility. Responsibility to our investors, to our customers, to our employees, to the contractors who work diligently with us, to the regulators across the continent who scrutinize our proposals, to the thousands of residents in communities located near our pipelines and power plants, and to the environment. We have always worked hard to ensure environmental sustainability wherever we operate.

Our success is a reflection of our exceptional team of 4,000 committed and motivated employees who bring skill, experience, energy and knowledge to the work they do. They are our competitive advantage.

building for tomorrow

$18 billion capital program underway

Pipelines

14 Keystone Pipeline System This US$12 billion pipeline will stretch 6,176 kilometres (3,837 miles) from Hardisty, Alberta to refining centres in the U.S. Midwest and Gulf Coast. When completed, Keystone will be one of the largest oil delivery systems in North America with the capacity to move 1.1 million barrels of oil a day to an American market looking for a growing and reliable supply. In 2008, TransCanada agreed to increase its ownership interest up to 79.99 per cent of Keystone.

Keystone will deliver 1.1 million barrels of oil per day to U.S. markets

15 Alberta System North Central Corridor Expansion Stretching 300 kilometres (186 miles) across northern Alberta, the $925 million North Central Corridor expansion will optimize natural gas flows on the Alberta System and allow TransCanada to address changing supply and demand dynamics in the province.

16 Bison Pipeline Project The 480 kilometre (298 mile) Bison Pipeline project will move natural gas from the Powder River Basin in Wyoming to the Northern Border System in North Dakota, tapping into a growing supply of U.S. Rockies natural gas for Midwest markets in the United States. The US$500 - US$600 million initiative is expected to begin shipping natural gas in late 2010.

17 Groundbirch **18** Horn River Pipeline Projects Groundbirch and Horn River are both designed to transport natural gas to market from shale gas deposits in northeastern British Columbia. TransCanada held a successful open season late in 2008 for the Groundbirch line, with commitments reaching 1.1 Bcf/d by 2014. The 77 kilometre (48 mile) project should be operational in late 2010. The company continues to work with potential shippers on the Horn River line. It is expected to start shipping gas in early 2011.

19 Northern Pipeline Projects Billed as the largest construction project in U.S. history, the US$26 billion (2007 dollars) Alaska Pipeline would transport natural gas from untapped reserves in Prudhoe Bay in the North to Alberta, where it would integrate with the Alberta System to provide access to diverse markets across North America. TransCanada has received a license from the Alaska government to advance the 2,760 kilometre (1,715 mile) line and is committed to moving the project through an open season in 2010 and the subsequent regulatory process. If successful, the project could be sanctioned in 2014, with natural gas anticipated to start flowing in 2018. In Canada, TransCanada and the other co-venture companies involved in the Mackenzie Gas Pipeline project continue to pursue approval of the proposed 1,200 kilometre (746 mile) pipeline project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework.

Attractive, low-risk projects...

Today, TransCanada is in the midst of an $18 billion capital program that will see a number of attractive, low-risk energy infrastructure projects completed over the next four years. Each project has

Energy

11 Bruce Power The $3.4 billion refurbishment of Bruce A Units 1 and 2 is expected to be completed in 2010. TransCanada's share of the capital investment is approximately $1.7 billion.

Bruce Power will add 1,500 MW to the Ontario market

When complete, the two units will be capable of delivering 1,500 MW of electricity to the Ontario market – enough to power one and a half million homes. Bruce Power is made up of two generating stations – A and B – with each consisting of four generating units. TransCanada owns 48.9 per cent of Bruce A and 31.6 per cent of Bruce B.

20 Portlands Energy 21 Halton Hills Construction of the Portlands Energy Centre is nearing completion and should be fully operational early in 2009. The 550 MW facility can supply 25 per cent of Toronto's electricity needs. This high-efficiency power plant is 50 per cent owned by TransCanada and is expected to cost $730 million. Work on the $670 million Halton Hills Generating Station is 50 per cent complete. The 683 MW facility should be operational late in 2010. Located 40 kilometres (25 miles) west of Toronto, Halton Hills will generate enough power for 600,000 homes.

22 Coolidge TransCanada continues to establish its energy footprint in the U.S. with a 575 MW power project in Coolidge, Arizona. The US$500 million plant will provide a quick response to peak power demands, have reserve capacity, and the ability to add power quickly to support reliability in the region. Construction is expected to begin in the summer of 2009 and be complete in 2011.

23 Cartier 24 Kibby The Cartier and Kibby Wind projects will generate clean, renewable electricity for thousands of families. Cartier is the largest wind power project in Canada, valued at $1.1 billion. Its six phases will ultimately generate 740 MW of power. Three phases are now complete, with the remainder coming on stream by 2012. TransCanada owns 62 per cent of Cartier. Residents of New England will ultimately see 44 wind turbines built between 2009 and 2010 as part of the US$320 million Kibby project. This 132 MW initiative will be the largest wind power development in the state, providing enough 'green energy' for 50,000 homes in the state of Maine.

been commercially secured through long-term contractual arrangements. These arrangements, along with our expertise in developing, building and operating large-scale energy infrastructure gives us confidence these projects will generate attractive, long-term returns for our shareholders. Looking forward, we will continue to cultivate a high quality portfolio of future growth opportunities that will create additional value for decades to come.

generating long-term returns for our shareholders

2008 Financial Highlights

Building on our track record of success

Net Income

$1.4 billion or $2.53 per common share, a 10% increase[2]

Comparable Earnings[1]

$1.3 billion or $2.25 per common share, an 8% increase[2]

Dividends Declared

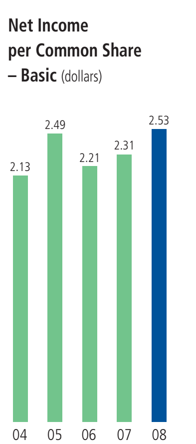
$1.44 per common share, a 6% increase[2]

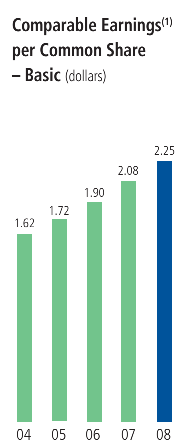
Funds Generated from Operations[1]

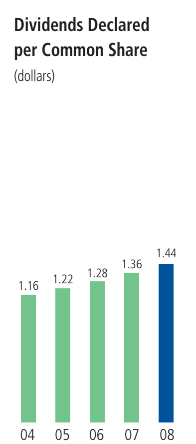
$3.0 billion, a 15% increase[2]

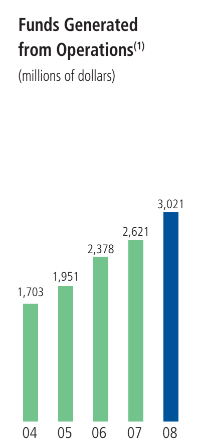
Capital Expenditures and Acquisitions

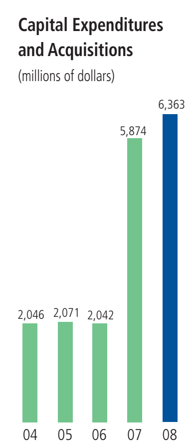
$6.4 billion invested in core businesses

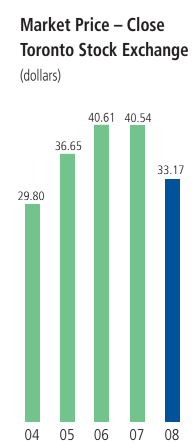












(1) Non-GAAP measure that does not have any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see page 16 in the Management's Discussion and Analysis of the 2008 Annual Report.

(2) Compared to 2007.

Financial Highlights

Year ended December 31 (millions of dollars)	2004	2005	2006	2007	**2008**
Income					
Comparable earnings[1]	786	839	925	1,100	**1,279**
Net income	1,032	1,209	1,079	1,223	**1,440**
Cash Flow					
Funds generated from operations	1,703	1,951	2,378	2,621	**3,021**
(Increase)/decrease in operating working capital	29	(49)	(303)	215	**(181)**
Net cash provided by operations	1,732	1,902	2,075	2,836	**2,840**
Capital expenditures and acquisitions	2,046	2,071	2,042	5,874	**6,363**
Balance Sheet					
Total assets	22,422	24,113	25,909	30,330	**39,414**
Long-term debt	9,749	9,640	10,887	12,377	**15,368**
Junior subordinated notes	–	–	–	975	**1,213**
Common shareholders' equity	6,565	7,206	7,701	9,785	**12,898**

Common Share Statistics Year ended December 31	2004	2005	2006	2007	**2008**
Comparable earnings[1] – Basic	$1.62	$1.72	$1.90	$2.08	**$2.25**
Net income per share – Basic	$2.13	$2.49	$2.21	$2.31	**$2.53**
Net income per share – Diluted	$2.12	$2.47	$2.20	$2.30	**$2.52**
Dividends declared per share	$1.16	$1.22	$1.28	$1.36	**$1.44**
Common shares outstanding (millions)					
Average for the year	484.1	486.2	488.0	529.9	**569.6**
End of year	484.9	487.2	489.0	539.8	**616.5**
Market Price – Close					
Toronto Stock Exchange (Canadian dollars)	29.80	36.65	40.61	40.54	**33.17**
New York Stock Exchange (U.S. dollars)	24.87	31.48	34.95	40.93	**27.14**

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Chairman's Message

Being able to say that 2008 was another strong year for TransCanada comes with considerable satisfaction. Success can be elusive at the best of times, but to be successful in this difficult global economy is a true achievement. TransCanada has done just that, producing strong financial results and making significant progress on a number of important initiatives.

Recognition of this performance was demonstrated by our ability to secure significant funding during 2008 for our large portfolio of attractive projects. This support in the capital markets was particularly gratifying and these funds will be used to continue to deliver long-term value to our shareholders.

In early February, as a further reflection of the confidence we have in the company, the Board approved an increase in the dividend on common shares for the ninth consecutive year, taking the quarterly dividend to $0.38 per common share or $1.52 annually. We also approved a three per cent discount on common shares issued under our dividend reinvestment and share purchase plan. The plan allows common and preferred shareholders to participate in our future by purchasing additional common shares at a discount.

While our financial track record is sound, we continue our commitment to social responsibility. TransCanada is one of only five companies from Canada to be recognized among this year's Global 100 Most Sustainable Corporations in the World. These companies are honoured as having the best ability to manage environmental, social and governance risks. In addition, TransCanada was named to The Dow Jones Sustainability Index, recognizing the financial performance of leading sustainability-driven companies worldwide.

The Board of Directors of TransCanada remains focused on strong corporate governance. Overseeing strategic direction and decision-making by the executive leadership are key responsibilities at all times but especially in this challenging environment, and we are focused on the goals and objectives we set for TransCanada over the long-term.

In the final analysis, though, delivering results must be founded on a practical philosophy, sound strategy and flawless execution. TransCanada's thoughtful, measured approach, the company's leaders and our 4,000 employees across North America are the reasons for our success. Along with all of the members of the Board of Directors, I would like to thank each team member for their extraordinary efforts in advancing our business in 2008. The company has doubled its asset base over the last decade to $40 billion through your contributions and continues on its path of becoming North America's leading energy infrastructure company.

On behalf of the Board of Directors,

S. Barry Jackson

Letter to Shareholders

TransCanada delivered strong operating and financial results in 2008. Each of our major business units generated strong results, with growing cash flows and excellent progress on major initiatives. Capital projects were executed to a very high standard, setting the stage for continued growth in earnings, cash flow and shareholder value in the years to come.

In 2008, TransCanada earned $1.4 billion or $2.53 per share, compared to $1.2 billion or $2.31 per share in 2007, an increase of 10 per cent on a per share basis. Comparable earnings(1) per share increased approximately eight per cent to $2.25 per share.

Funds generated from operations(1) increased substantially, to a record $3 billion. That represents a 15 per cent increase over 2007 and is nearly three times as large as our funds generated from operations(1) in 1999.

Our long term shareholders will recall that TransCanada established a new strategic direction in 2000, shedding international assets, exiting the volatile midstream business and focusing our efforts on pipeline and power generation opportunities within North America. In 2001 we further reduced our exposure to commodity price volatility by selling our natural gas marketing and trading business.

Since 1999 TransCanada has invested approximately $24 billion in stable, value-creating pipeline and energy growth opportunities. Those investments have transformed TransCanada: today we are the unquestioned leader in North American natural gas transmission; we are building a large and very competitive oil pipeline business; we are one of North America's largest and most profitable natural gas storage operators; and we own the largest and most profitable private-sector power business in Canada.

Our investments have been both large and profitable. Since 1999 our comparable earnings(1) per share have grown at a compound average annual rate of nine per cent, from $1.08 in 1999 to $2.25 in 2008. Over that same period we generated significant additional earnings and cash proceeds from the sale of non-core assets and certain other items. These transactions funded a significant portion of our capital program over the past nine years.

TransCanada's strong financial performance has enabled our Board of Directors to increase our dividend on common shares in each of the past nine years. Most recently, we increased our dividend to $1.52 per share on an annualized basis, an increase of six percent over 2008. Our Board of Directors also approved an increase in the discount on the issuance of common shares from treasury under our Dividend Reinvestment and Share Purchase Plan from two to three per cent. This provides existing shareholders with an opportunity to participate in the future growth of the company by reinvesting their dividends in additional common shares.

Our natural gas pipeline business achieved excellent results in 2008. Each day we deliver approximately 20 per cent of the natural gas consumed in North America, and we continue to build on that industry-leading position. We are currently investing more than $1.5 billion to expand and extend our Alberta System. We have asked Canada's National Energy Board to assume jurisdiction over the Alberta System, a move that will enable TransCanada to compete for new natural gas supplies in British Columbia, the Northwest Territories and Alaska. We are excited by the prospects for shale gas development in northeastern British Columbia and we look forward to extending our system to serve producers in the Montney and Horn River shale plays.

We continue to build a large scale, profitable natural gas pipeline business in the United States. Our 2007 acquisition of the ANR System has proven to be both profitable and well-timed. Rockies volumes have filled the southwest leg of ANR, and the emerging Haynesville and Fayetteville shale plays are expected to contribute significant volumes to the southeast leg in the years ahead. ANR's large natural gas storage business in Michigan has grown significantly since acquisition, and we see significant capital investment opportunities throughout the ANR System in the years ahead. Notably, we now have a strong commercial and business development team in Houston, Texas, improving our access to natural gas pipeline opportunities in the United States.

Our efforts to bring Mackenzie and Alaska gas to market continue to move forward. These large, long term projects will connect more than 4 Bcf/d to our Alberta System, providing shippers with unparalleled access to premium North American markets through our GTN, Northern Border, Great Lakes and Canadian Mainline systems.

Five years ago we identified the opportunity to move growing volumes of crude oil from Alberta's oilsands to major United States refining centres in the southern Midwest and Gulf Coast regions. Construction is well underway on our Keystone pipeline from Hardisty, Alberta to Wood River and Patoka, Illinois, with flows commencing in early 2010. We are currently finalizing regulatory applications for the Keystone expansion, which will extend our reach to premium markets in the Gulf Coast region. Both Keystone and the Gulf Coast expansion are underpinned by long-term contracts to move more than 900,000 barrels per day.

Our power generation business has grown more than tenfold over the past nine years, and projects currently under construction will deliver significant growth in cash flow and earnings over the next three years. The 550 MW Portlands Energy Centre in Toronto is expected to be in service in first quarter 2009. The 683 MW Halton Hills Generating Station located west of Toronto is expected to be in service in third quarter 2010. The 1,500 MW refurbishment of Bruce A Units 1 and 2 is also expected to come on line in

2010. Other projects now under construction or in development include the Cartier and Kibby Wind projects and the Coolidge Generating Station. These large-scale generating projects are highly efficient, located in premium markets, and underpinned by strong, long-term commercial arrangements.

Energy infrastructure is a long-cycle, capital intensive business, and we structure our projects carefully to ensure stable profitability throughout the cycle. With a strong balance sheet and significant liquidity, TransCanada has the ability to endure turbulent economic times, today and in the future. Our strong cash flows from existing assets together with continued access to capital markets means we are well positioned to fund our sizeable capital program and deliver growing cash flow and earnings in the years ahead.

TransCanada's enduring success is a reflection of the skills and commitment of our outstanding team of 4,000 employees located in Calgary, Houston and many other regions across North America. Our employees truly are our competitive advantage. Their operating and commercial expertise, their project development and execution capabilities and their dedication to value creation are unparalleled in the energy infrastructure industry. I am confident that we will continue to deliver significant shareholder value for many years to come.

Hal Kvisle
President and Chief Executive Officer

(1) Non-GAAP measure that does not have any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see page 16 in the Management's Discussion and Analysis of the 2008 Annual Report.

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The Management's Discussion and Analysis (MD&A) dated February 23, 2009 should be read in conjunction with the audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) and the notes thereto for the year ended December 31, 2008, which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). This MD&A covers TransCanada's financial position and operations as at and for the year ended December 31, 2008. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms used in this MD&A are identified in the Glossary of Terms in the Company's 2008 Annual Report.

TRANSCANADA OVERVIEW

In 2008, TransCanada celebrated the 50th anniversary of the completion of its original pipeline from Alberta to Ontario and Québec. Fifty years of experience has established TransCanada as a significant player in the development and operation of North American energy infrastructure, including natural gas and oil pipelines, power generation plants, and natural gas storage facilities.

TransCanada has invested approximately $24 billion in capital projects in the last nine years, and currently has more than $40 billion in total assets. The Company is currently executing an $18 billion capital program and most of the projects are expected to be completed by 2012. Over the longer term, TransCanada intends to continue to pursue and develop its substantial portfolio of large-scale infrastructure projects. TransCanada is committed to maintaining the financial strength required to build the energy infrastructure needed to serve increased energy demand, respond to shifting energy supply-demand dynamics and replace aging North American infrastructure.

Pipelines Assets

The TransCanada network of more than 59,000 kilometres (km) (36,661 miles) of wholly owned and 7,800 km (4,847 miles) of partially owned natural gas pipelines connect virtually every major natural gas supply basin and market, transporting 20 per cent of the natural gas consumed in North America. TransCanada's natural gas pipelines link gas supplies from Western Canada, the United States (U.S.) mid-continent and Gulf of Mexico to premium North American markets. These assets are well positioned to connect emerging natural gas supplies, including northern gas, northeastern British Columbia (B.C.) and U.S. shale gas, and offshore liquefied natural gas (LNG) imports, to growing markets.

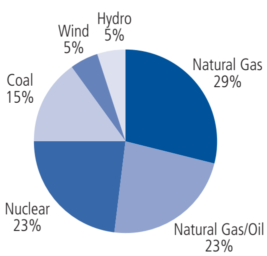
TransCanada's Alberta System gathered 66 per cent of the natural gas produced in Western Canada or 15 per cent of total North American production in 2008. TransCanada exports natural gas from the Western Canada Sedimentary Basin (WCSB) to Eastern Canada and the U.S. West, Midwest, and Northeast through three wholly owned pipeline systems: the Canadian Mainline, the GTN System and Foothills. TransCanada also exports natural gas from the WCSB to Eastern Canada and to the U.S. West, Midwest, and Northeast through six partially owned natural gas pipeline systems: Great Lakes, Iroquois, Portland, TQM, Northern Border and Tuscarora. Certain of these pipeline systems are held through the Company's 32.1 per cent interest in TC PipeLines, LP (PipeLines LP).

ANR was acquired in February 2007. ANR transports natural gas from producing fields located primarily in Oklahoma, Texas, Louisiana and the Gulf of Mexico to markets located in Wisconsin, Michigan, Illinois, Ohio and Indiana. It also connects with numerous other natural gas pipelines, providing customers with access to diverse sources of North American supply, including Western Canada and the Rocky Mountain region, and to a variety of end-user markets in the midwestern and northeastern U.S. ANR owns and operates 250 billion cubic feet (Bcf) of regulated natural gas storage capacity in Michigan.

In addition, the Company has agreed to increase its ownership interest up to 79.99 per cent in each of TransCanada Keystone Pipeline Limited Partnership and TransCanada Keystone Pipeline, LP (collectively, Keystone partnerships). TransCanada has partnered with ConocoPhillips, a global, integrated oil and gas producer and refiner to build the Keystone crude oil pipeline. Currently under construction, the Keystone pipeline will transport 1.1 million barrels per day (Bbl/d) of crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka in Illinois, and at Cushing, Oklahoma, and to U.S. Gulf Coast markets. The pipeline is supported by long-term contracts with strong counterparties and provides a low-cost shipping option. While the current economic slowdown and low oil price environment have eased the pace of oil sands project activity, developments in the medium to long term in Alberta will provide attractive opportunities for further additions to crude oil transmission infrastructure.

Energy Assets
TransCanada's Energy business has grown from 754 megawatts (MW) in 1999 to more than 10,900 MW in 2008. The Company's diverse power generation portfolio of primarily low-cost, baseload or long-term contracted facilities comprises a total of 19 plants in Alberta, Eastern Canada, New England, and New York City. The accompanying graph illustrates each fuel source as a percentage of the Company's overall Energy portfolio:

Power by Fuel Source



TransCanada has developed a significant non-regulated natural gas storage business in Alberta where the Company owns or has rights to 120 Bcf or approximately one-third of the natural gas storage capacity in the province.

Opportunities and developments in the Company's Pipelines and Energy businesses are discussed further in the "Pipelines" and "Energy" sections of this MD&A.

TRANSCANADA'S STRATEGY

TransCanada's vision is to be the leading energy infrastructure company in North America with a strong focus on pipelines and power generation opportunities located in regions where it has or can develop significant competitive advantage. Since 2000, TransCanada's key strategies continue to evolve with the Company's growth and development and its changing business environment. TransCanada's corporate strategy integrates five fundamental value-creating activities:

1. **Maximize the full-life value of TransCanada's infrastructure assets and commercial positions**
2. **Cultivate a focused portfolio of high quality development options**
3. **Commercially develop and physically execute new asset investment programs**
4. **Maximize TransCanada's competitive strengths**
5. **Maximize TransCanada's financial strength and reputation**

These strategies are defined by an integrated set of activities and performance objectives:

Maximize the full-life value of TransCanada's infrastructure assets and commercial positions
TransCanada relies on a low-risk business model to maximize the full-life value of existing assets and positions that generate predictable, sustainable streams of cash flows and earnings. In the Company's Pipelines business, the natural gas pipeline network connects traditional and emerging basins to growing markets offering effective service and competitive rates. TransCanada's Energy business supplies growing power markets through long-term power purchase agreements, and low-cost baseload generation. The Company's activities in gas, nuclear, wind and hydro energy sources demonstrate its commitment to a sustainable energy future. TransCanada continues to make its long-term commercial and physical asset operations a priority. The Company attempts to maximize the life and value of its assets by focusing on sustainable business initiatives derived from engaging in market and regulatory developments, combined with an accretive capital investment program.

Cultivate a focused portfolio of high quality development options
The Company's core western and eastern regions are the primary focus of growth initiatives in the Pipelines and Energy businesses. Consideration is given to new markets with good fundamentals where TransCanada has or can develop competitive strengths. There is a continued focus on low-cost, baseload power assets as well as on power and natural gas storage assets supported by firm, long-term contracts with reputable counterparties. Greenfield development and acquisition of power generation, power transmission and natural gas storage are considered if they meet the Company's investment standards. Greenfield and brownfield pipeline projects are being pursued to diversify the Pipelines business and add incremental value to existing assets. Key areas of focus include greenfield development options to connect the Company's natural gas pipelines to northern gas reserves and emerging Canadian and U.S. shale gas supplies, and transporting crude oil from the Alberta oil sands. Other possible growth opportunities include acquiring natural gas and

oil transmission assets that complement TransCanada's existing assets, acquiring partners' interests in associated pipelines and acquiring stand-alone transmission enterprises in new regions of North America.

Commercially develop and physically execute new asset investment programs
TransCanada's current $18 billion capital program is expected to begin generating revenue over the next four years beginning in 2009. The Company is committed to completing the projects in its capital programs on time and on budget to deliver service to its customers and returns to its shareholders. Its large portfolio of projects is characterized by highly contracted, long-term revenue streams and limited exposure to capital cost risks. These are key features of TransCanada's model for managing construction risks and improving the return realized from new investment programs. This strategy will be applied to Pipelines and Energy growth opportunities that address North America's emerging energy infrastructure needs.

Maximize TransCanada's competitive strengths
TransCanada will use its competitive strengths to achieve responsible, profitable operations and growth. In the Pipelines and Energy infrastructure businesses, size and scale of operations must be large enough to compete effectively and offer recognized value to customers. The Company believes its competitive strengths include the discipline it applies in operations, governance and project, financial and risk management, and its ability to obtain capital at suitable terms. TransCanada strives to provide customers with safe, low-cost, reliable and responsible service by such means as improved efficiencies, operational reliability and enhanced environmental and safety performance. The Company also strives to maintain constructive relationships with its key stakeholder groups. Utilizing these strengths is the responsibility of all employees, and all employees contribute to the success of the Company. To maximize the quality, capability and contribution of the Company's employees, management encourages and supports its employees' innovative thinking, development and leadership.

Maximize TransCanada's financial strength and reputation
TransCanada continues to value its reputation for financial strength based on a history of predictable, growing earnings and cash flow. The Company continues to communicate its financial performance to current and prospective debt and equity holders, while making its management of risks transparent. TransCanada strives to maintain access to low-cost capital in all market environments to enable it to capture growth opportunities and improve its financial performance.

CONSOLIDATED FINANCIAL REVIEW

SELECTED THREE YEAR CONSOLIDATED FINANCIAL DATA
(millions of dollars, except per share amounts)

	2008	2007	2006
Income Statement			
Revenues	**8,619**	8,828	7,520
Net income			
Continuing operations	**1,440**	1,223	1,051
Discontinued operations	**–**	–	28
	1,440	1,223	1,079
Comparable earnings[1]	**1,279**	1,100	925
Per Common Share Data			
Net income – basic			
Continuing operations	**$2.53**	$2.31	$2.15
Discontinued operations	**–**	–	0.06
	$2.53	$2.31	$2.21
Net income – diluted			
Continuing operations	**$2.52**	$2.30	$2.14
Discontinued operations	**–**	–	0.06
	$2.52	$2.30	$2.20
Comparable earnings per share[1]	**$2.25**	$2.08	$1.90
Dividends declared	**$1.44**	$1.36	$1.28
Summarized Cash Flow			
Funds generated from operations[1]	**3,021**	2,621	2,378
(Increase)/decrease in operating working capital	**(181)**	215	(303)
Net cash provided by operations	**2,840**	2,836	2,075
Balance Sheet			
Total assets	**39,414**	30,330	25,909
Total long-term liabilities	**20,392**	16,511	14,464

[1] Refer to the "Non-GAAP Measures" section of this MD&A for further discussion of comparable earnings, comparable earnings per share and funds generated from operations.

HIGHLIGHTS

Net Income

- Net income was $1,440 million or $2.53 per share in 2008 compared to net income of $1,223 million or $2.31 per share in 2007.

Comparable Earnings

- TransCanada's comparable earnings of $1,279 million in 2008 excluded $152 million of gains from bankruptcy settlements with certain subsidiaries of Calpine Corporation (Calpine), proceeds of $10 million from a lawsuit settlement, a $27 million writedown of costs for the Broadwater LNG project (Broadwater) and $26 million of favourable income tax adjustments. Comparable earnings of $1,100 million in 2007 excluded favourable income tax adjustments of $102 million, a gain of $14 million on the sale of land and $7 million of net unrealized gains from changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts.

Cash from Operations

- Net cash provided by operations was $2,840 million in 2008, an increase of $4 million from 2007.
- Funds generated from operations were $3,021 million in 2008, an increase of $400 million or 15 per cent from 2007.

Investing Activities

- TransCanada invested $6.4 billion in its Pipelines and Energy businesses in 2008, including the following:
  - the acquisition of the Ravenswood facility in August 2008 for US$2.9 billion, subject to certain post-closing adjustments;
  - capital expenditures of $1.8 billion for Pipelines projects, including Keystone and North Central Corridor; and
  - capital expenditures of $1.3 billion for Energy projects, including the Bruce A restart of Units 1 and 2, and construction of Portlands Energy, Halton Hills, Kibby Wind and Cartier Wind.

Financing Activities

- In 2008, TransCanada issued $2.2 billion of long-term debt (net of issue costs) and $2.4 billion of common shares (net of issue costs), comprised primarily of the following:
  - in fourth quarter 2008, the issuance of 35.1 million common shares at $33.00 each, resulting in gross proceeds of $1.2 billion;
  - in second quarter 2008, the issuance of 34.7 million common shares at $36.50 each, resulting in gross proceeds of $1.3 billion;
  - in August 2008, the issuance of US$1.5 billion of Senior Unsecured Notes;
  - in August 2008, the issuance of $500 million of Medium-Term Notes; and
  - in accordance with its Dividend Reinvestment and Share Purchase Plan (DRP), the issuance of 6.0 million common shares from treasury in lieu of making cash dividend payments totalling $218 million.
- In February 2009, the Company issued $700 million of Medium-Term Notes.
- In January 2009, the Company issued US$2.0 billion of Senior Unsecured Notes.
- In November 2008, TransCanada established a new US$1.0 billion committed bank facility.
- In June 2008, the Company entered into an agreement for a US$1.5 billion one-year bridge loan facility. In August 2008, the Company drew US$255 million and cancelled the remainder of the commitment.

Balance Sheet

- Total assets increased by $9.1 billion to $39.4 billion in 2008 compared to 2007, primarily due to the acquisition of the Ravenswood facility, investments in Energy and Pipelines capital projects, and the effect of a stronger U.S. dollar.
- TransCanada's shareholders' equity increased by $3.1 billion to $12.9 billion in 2008 compared to the previous year.

Dividend

- On February 2, 2009, the Board of Directors of TransCanada increased the quarterly dividend on the Company's outstanding common shares for the quarter ending March 31, 2009 by six per cent to $0.38 per share from $0.36 per share. This was the ninth consecutive year in which the common share dividend was increased.

Refer to "Results of Operations" below and to the "Liquidity and Capital Resources" section of this MD&A for further discussion of these highlights.

SEGMENT RESULTS
Reconciliation of Comparable Earnings to Net Income

Year ended December 31 (millions of dollars except per share amounts)	2008	2007	2006
Pipelines			
Comparable earnings	**740**	686	529
Specific items (net of tax):			
Calpine bankruptcy settlements	**152**	–	–
GTN lawsuit settlement	**10**	–	–
Bankruptcy settlement with Mirant	**–**	–	18
Gain on sale of Northern Border Partners, L.P. interest	**–**	–	13
Net earnings	**902**	686	560
Energy			
Comparable earnings	**641**	459	429
Specific items (net of tax, where applicable):			
Writedown of Broadwater costs	**(27)**	–	–
Gain on sale of land	**–**	14	–
Fair value adjustments of natural gas storage inventory and forward contracts	**–**	7	–
Income tax reassessments and adjustments	**–**	34	23
Net earnings	**614**	514	452
Corporate			
Comparable expenses	**(102)**	(45)	(33)
Specific item:			
Income tax reassessments and adjustments	**26**	68	72
Net (expenses)/earnings	**(76)**	23	39
Net Income			
Continuing operations(1)	**1,440**	1,223	1,051
Discontinued operations	**–**	–	28
Net Income	**1,440**	1,223	1,079
Comparable Earnings(1)	**1,279**	1,100	925
Net Income Per Share – Basic			
Continuing operations(2)	**$2.53**	$2.31	$2.15
Discontinued operations	**–**	–	0.06
	$2.53	$2.31	$2.21
Comparable Earnings Per Share(2)	**$2.25**	$2.08	$1.90

(1)**Comparable Earnings**	**1,279**	1,100	925
Specific items (net of tax, where applicable):			
Calpine bankruptcy settlements	**152**	–	–
GTN lawsuit settlement	**10**	–	–
Writedown of Broadwater costs	**(27)**	–	–
Gain on sale of land	**–**	14	–
Fair value adjustments of natural gas storage inventory and forward contracts	–	7	–
Bankruptcy settlement with Mirant	**–**	–	18
Gain on sale of Northern Border Partners, L.P. interest	**–**	–	13
Income tax reassessments and adjustments	**26**	102	95
Net Income from Continuing Operations	**1,440**	1,223	1,051

(2)**Comparable Earnings Per Share**	**$2.25**	$2.08	$1.90
Specific items – per share:			
Calpine bankruptcy settlements	**0.27**	–	–
GTN lawsuit settlement	**0.02**	–	–
Writedown of Broadwater costs	**(0.05)**	–	–
Gain on sale of land	**–**	0.03	–
Fair value adjustments of natural gas storage inventory and forward contracts	–	0.01	–
Bankruptcy settlement with Mirant	**–**	–	0.04
Gain on sale of Northern Border Partners, L.P. interest	**–**	–	0.03
Income tax reassessments and adjustments	**0.04**	0.19	0.18
Net Income Per Share from Continuing Operations	**$2.53**	$2.31	$2.15

RESULTS OF OPERATIONS

Net income and net income from continuing operations (net earnings) were $1,440 million or $2.53 per share in 2008 compared to $1,223 million or $2.31 per share in 2007. Net income and net earnings in 2006 were $1,079 million or $2.21 per share and $1,051 million or $2.15 per share, respectively. Results in 2006 included net income from discontinued operations of $28 million or $0.06 per share, reflecting bankruptcy settlements with Mirant Corporation and certain of its subsidiaries (Mirant) related to their transactions with TransCanada's Gas Marketing business. TransCanada divested its Gas Marketing business in 2001.

Net income in 2008 included $152 million of after-tax gains on shares received by the GTN System and Portland from the Calpine bankruptcy settlements, $10 million after tax of GTN System lawsuit settlement proceeds and a $27 million after-tax writedown of costs previously capitalized for Broadwater. Net income in 2008 also included $26 million of favourable income tax adjustments from an internal restructuring and realization of losses. Net income in 2007 included $102 million ($68 million in Corporate and $34 million in Energy) of favourable income tax adjustments recorded in 2007 relating to changes in Canadian federal and provincial corporate income tax legislation, the resolution of certain tax matters and an internal restructuring. Net income in 2007 also included an after-tax gain of $14 million on the sale of land and $7 million after tax of net unrealized gains resulting from changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Net earnings in 2006 included $95 million of favourable income tax adjustments, proceeds from an $18 million after-tax bankruptcy settlement with Mirant and an after-tax gain of $13 million from the sale of TransCanada's general partner interest in Northern Border Partners, L.P.

Excluding the above-noted items, comparable earnings for 2008, 2007 and 2006 were $1,279 million ($2.25 per share), $1,100 million ($2.08 per share) and $925 million ($1.90 per share), respectively. Comparable earnings in 2008 increased $179 million or $0.17 per share compared to 2007 due to higher earnings in the Energy and Pipelines businesses, partially offset by an increase in net expenses in Corporate. Pipelines' earnings increased in 2008 compared to 2007 primarily due to a full year of earnings in 2008 from ANR. Energy's earnings from Western Power, Eastern Power and Bruce A and Bruce B (collectively, Bruce Power) operations increased in 2008 compared to 2007 primarily due to higher realized prices. Corporate net expenses in 2008 increased from 2007 primarily due to unrealized losses from the changes in the fair value of derivatives, which are used to manage TransCanada's exposure to rising interest rates but do not qualify for hedge accounting, and higher financial charges.

Comparable earnings increased $175 million or $0.18 per share in 2007 compared to 2006 primarily due to additional earnings from the acquisition of ANR in February 2007, a full year of earnings in 2007 from the Bécancour and Edson facilities, and positive impacts from rate case settlements for the GTN System and Canadian Mainline. These increases were partially offset by a lower contribution from Bruce Power in 2007.

Results in each business segment are discussed further in the "Pipelines", "Energy" and "Corporate" sections of this MD&A.

FORWARD-LOOKING INFORMATION

This MD&A may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada shareholders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future financial and operational plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects and financial performance of TransCanada and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules, operating and financial results and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of the Company's pipeline and energy assets, the availability and price of energy commodities, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and the current economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, including those material risks discussed in the "Pipelines", "Energy" and "Risk Management and Financial Instruments" sections in this MD&A, which could cause TransCanada's actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC). Readers are cautioned to not place undue reliance on this forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and to not use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

NON-GAAP MEASURES

TransCanada uses the measures "comparable earnings", "comparable earnings per share", "funds generated from operations" and "operating income" in this MD&A. These measures do not have any standardized meaning prescribed by Canadian GAAP. They are, therefore, considered to be non-GAAP measures and are unlikely to be comparable to similar measures presented by other entities. Management of TransCanada uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TransCanada's operating performance, liquidity and ability to generate funds to finance operations.

Management uses comparable earnings/(expenses) to better evaluate trends in the Company's underlying operations. Comparable earnings comprise net income from continuing operations adjusted for specific items that are significant, but are not reflective of the Company's underlying operations in the year. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating comparable earnings, some of which may recur. Specific items may include but are not limited to certain income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and certain fair value adjustments. The Segment Results table in this MD&A presents a reconciliation of comparable earnings to net income from continuing operations. Comparable earnings per share is calculated by dividing comparable earnings by the weighted average number of shares outstanding for the period.

Funds generated from operations comprises net cash provided by operations before changes in operating working capital. A reconciliation of funds generated from operations to net cash provided by operations is presented in the Summarized Cash Flow table in the "Liquidity and Capital Resources" section of this MD&A.

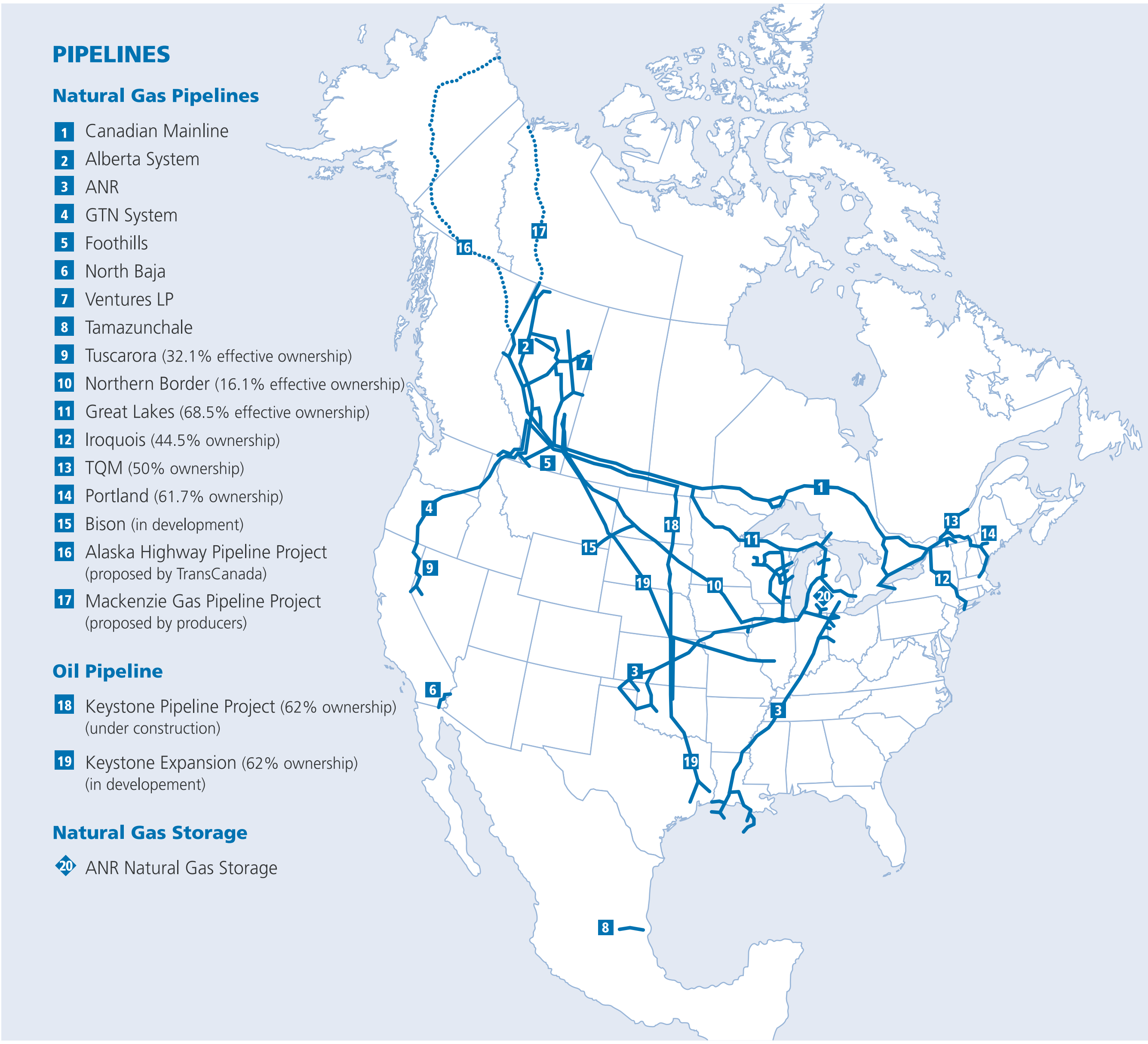
Operating income is reported in the Company's Energy business segment and comprises revenues less operating expenses as shown on the Consolidated Income Statement. A reconciliation of operating income to net income is presented in the "Energy" section of this MD&A.

OUTLOOK

TransCanada's corporate strategy is underpinned by a long-term focus on growing its Pipelines and Energy businesses in a disciplined and measured manner. In 2009 and beyond, TransCanada expects its net earnings and cash flow, combined with a strong balance sheet and proven access to capital markets, to provide the financial strength TransCanada will need to complete its current capital expenditure program and continue to pursue other long-term growth opportunities and create additional value for its shareholders in the same disciplined and measured manner utilized in developing its current capital expenditure program. TransCanada believes this prudence is especially important in the economic environment that currently exists in North America. In 2009, the Company will continue to implement its strategy and grow the Pipelines and Energy businesses as discussed in the "TransCanada's Strategy" section of this MD&A.

The current economic slowdown is not expected to have a significant impact on TransCanada's near-term earnings as the majority of TransCanada's operations are underpinned by either long-term contracts or earn a regulated return. In addition, TransCanada's continued focus on risk management is expected to further lessen the negative impact of the current economic slowdown to TransCanada.

The Company's results in 2009 may be affected positively or negatively by a number of factors and developments as discussed throughout this MD&A, including without limitation, the factors and developments discussed in the "Forward-Looking Information", "Pipelines – Business Risks" and "Energy – Business Risks" sections. Refer to the "Pipelines – Outlook", "Energy – Outlook" and "Corporate – Outlook" sections of this MD&A for further discussion of outlook.



CANADIAN MAINLINE Owned 100 per cent by TransCanada, the Canadian Mainline is a 14,101 km (8,762 miles) natural gas transmission system in Canada that extends from the Alberta/Saskatchewan border east to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the U.S.

ALBERTA SYSTEM Owned 100 per cent by TransCanada, the Alberta System is a 23,705 km (14,730 miles) natural gas transmission system in Alberta. One of the largest transmission systems in North America, it gathers natural gas for use within the province and delivers it to provincial boundary points for connection with the Company's Canadian Mainline and Foothills natural gas pipelines and with the natural gas pipelines of other companies.

ANR Owned 100 per cent by TransCanada, ANR is a 17,000 km (10,563 miles) transmission system that transports natural gas from producing fields located primarily in Texas and Oklahoma on its southwest leg and in the Gulf of Mexico and Louisiana on its southeast leg. The system extends to markets located mainly in Wisconsin, Michigan, Illinois, Ohio and Indiana. ANR's natural gas pipeline also connects with other natural gas pipelines providing access to diverse sources of North American supply including Western Canada and the Rocky Mountain supply basin, and a variety of markets in the midwestern and northeastern U.S. ANR also owns and operates regulated underground natural gas storage facilities in Michigan with a total capacity of 250 Bcf.

GTN SYSTEM Owned 100 per cent by TransCanada, the GTN System is a 2,174 km (1,351 miles) natural gas transmission system that links Foothills with Pacific Gas and Electric Company's California Gas Transmission System, with Williams Companies, Inc.'s Northwest Pipeline in Washington and Oregon, and with Tuscarora.

FOOTHILLS Owned 100 per cent by TransCanada, the 1,241 km (771 miles) Foothills transmission system in Western Canada carries natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest, California and Nevada.

NORTH BAJA Owned 100 per cent by TransCanada, the North Baja natural gas transmission system extends 129 km (80 miles) from Ehrenberg in southwestern Arizona to a point near Ogilby, California on the California/Mexico border and connects with the Gasoducto Bajanorte natural gas pipeline system in Mexico.

VENTURES LP Owned 100 per cent by TransCanada, Ventures LP is comprised of a 161 km (100 miles) pipeline and related facilities that supply natural gas to the oil sands region near Fort McMurray, Alberta as well as a 27 km (17 miles) pipeline that supplies natural gas to a petrochemical complex at Joffre, Alberta.

TAMAZUNCHALE Owned 100 per cent by TransCanada, the 130 km (81 miles) Tamazunchale natural gas pipeline in east central Mexico extends from the facilities of Pemex Gas near Naranjos, Veracruz, to an electricity generating station near Tamazunchale, San Luis Potosi.

TUSCARORA Owned 100 per cent by PipeLines LP, Tuscarora is a 491 km (305 miles) pipeline system transporting natural gas from the GTN System at Malin, Oregon, to Wadsworth, Nevada, with delivery points in northeastern California and northwestern Nevada. TransCanada operates Tuscarora and effectively owns 32.1 per cent of the system through its 32.1 per cent interest in PipeLines LP.

NORTHERN BORDER Owned 50 per cent by PipeLines LP, the 2,250 km (1,398 miles) Northern Border natural gas transmission system serves the U.S. Midwest from a connection with Foothills near Monchy, Saskatchewan. TransCanada operates Northern Border and effectively owns 16.1 per cent of the system through its 32.1 per cent interest in PipeLines LP.

GREAT LAKES Owned 53.6 per cent by TransCanada and 46.4 per cent by PipeLines LP, the 3,404 km (2,115 miles) Great Lakes natural gas transmission system connects with the Canadian Mainline at Emerson, Manitoba, and serves markets in Central Canada and the midwestern U.S. TransCanada operates Great Lakes and effectively owns 68.5 per cent of the system through its 53.6 per cent direct ownership interest and its indirect ownership, which it has through its 32.1 per cent interest in PipeLines LP.

IROQUOIS Owned 44.5 per cent by TransCanada, the 666 km (414 miles) Iroquois pipeline system connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S.

TQM Owned 50 per cent by TransCanada, TQM is a 572 km (355 miles) pipeline system that connects with the Canadian Mainline and transports natural gas from Montréal to Québec City in Québec, and connects with the Portland system. TQM is operated by TransCanada.

PORTLAND Owned 61.7 per cent by TransCanada, Portland is a 474 km (295 miles) pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. Portland is operated by TransCanada.

BISON The Bison pipeline project is a proposed 480 km (298 miles) pipeline from the Powder River Basin in Wyoming to the Northern Border system in North Dakota.

KEYSTONE Keystone is an oil pipeline consisting of 3,456 km (2,147 miles) of pipe under construction that will initially transport crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma. In addition, an expansion to the U.S. Gulf Coast is under development, which is expected to add approximately 2,720 km (1,690 miles) of pipe to the system. Commissioning of the segment to Wood River and Patoka is expected to begin in late 2009. Commissioning of the segment to Cushing is expected to begin in late 2010. The expansion to the U.S. Gulf Coast is expected to be commissioned in 2012, subject to regulatory approvals. In 2008, TransCanada agreed to increase its ownership interest in Keystone up to 79.99 per cent. At December 31, 2008, TransCanada owned 62 per cent of Keystone.

TRANSGAS Owned 46.5 per cent by TransCanada, TransGas is a 344 km (214 miles) natural gas pipeline system extending from Mariquita in the central region of Colombia to Cali in southwestern Colombia.

GAS PACIFICO/INNERGY Owned 30 per cent by TransCanada, Gas Pacifico is a 540 km (336 miles) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada also has a 30 per cent ownership interest in INNERGY, an industrial natural gas marketing company based in Concepción that markets natural gas transported on Gas Pacifico.

PIPELINES – HIGHLIGHTS

- Net income from Pipelines was $902 million in 2008, an increase of $216 million from $686 million in 2007. Comparable earnings from Pipelines were $740 million in 2008, an increase of $54 million from $686 million in 2007.
- The Keystone partnerships began building the portion of the Keystone pipeline that will deliver oil to markets in the U.S. Midwest and to Cushing, Oklahoma, and secured shipping commitments for a future expansion to serve markets on the U.S. Gulf Coast.
- TransCanada began construction of the North Central Corridor expansion at a cost of approximately $925 million following approval from the Alberta Utilities Commission (AUC).
- TransCanada received approval from the AUC for the Alberta System's 2008-2009 Revenue Requirement Settlement.
- TransCanada filed an application with the National Energy Board (NEB) to establish federal jurisdiction over the Alberta System. A decision is expected in first quarter 2009.
- ANR completed the second phase of its storage enhancement project (STEP 2008), which added 14 Bcf of storage capacity.
- TransCanada was awarded a license from the State of Alaska to construct the Alaska Pipeline Project under the *Alaska Gasline Inducement Act* (AGIA).

PIPELINES RESULTS
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Wholly Owned Pipelines			
Canadian Mainline	**278**	273	239
Alberta System	**145**	138	136
ANR[(1)]	**132**	104	n/a
GTN	**65**	58	46
Foothills	**24**	26	27
	644	599	448
Other Pipelines			
Great Lakes[(2)]	**44**	47	44
PipeLines LP[(3)]	**25**	18	4
Iroquois	**18**	15	15
Tamazunchale[(4)]	**16**	10	2
Other[(5)]	**34**	46	51
Northern Development	**(9)**	(7)	(5)
General, administrative, support costs and other	**(32)**	(42)	(30)
	96	87	81
Comparable Earnings[(6)]	**740**	686	529
Calpine bankruptcy settlements[(7)]	**152**	–	–
GTN lawsuit settlement	**10**	–	–
Bankruptcy settlement with Mirant	**–**	–	18
Gain on sale of Northern Border Partners, L.P. interest	**–**	–	13
Net Earnings	**902**	686	560

(1) ANR's results include earnings from the date of acquisition of February 22, 2007.

(2) Great Lakes' results reflect TransCanada's 53.6 per cent ownership in Great Lakes since February 22, 2007 and 50 per cent ownership prior to that date.

(3) PipeLines LP's results include TransCanada's effective ownership of an additional 14.9 per cent interest in Great Lakes since February 22, 2007 as a result of PipeLines LP's acquisition of a 46.4 per cent interest in Great Lakes and TransCanada's 32.1 per cent interest in PipeLines LP. Prior to this date, TransCanada had a 13.4 per cent ownership interest in PipeLines LP.

(4) Tamazunchale's results include operations since December 1, 2006.

(5) Other includes results of Portland, Ventures LP, TQM, TransGas and Gas Pacifico/INNERGY.

(6) Refer to the "Non-GAAP Measures" section of this MD&A for further discussion of comparable earnings.

(7) GTN and Portland received shares of Calpine with an initial after-tax value of $95 million and $38 million (TransCanada's share), respectively, from the bankruptcy settlements with Calpine. These shares were subsequently sold for an additional after-tax gain of $19 million.

Net earnings from the Pipelines business were $902 million in 2008 compared to $686 million in 2007 and $560 million in 2006. Comparable earnings from the Pipelines business of $740 million in 2008 excluded the $152 million after-tax ($279 million pre-tax) gains received by Portland and the GTN System from the bankruptcy settlements with Calpine and $10 million after-tax ($17 million pre-tax) proceeds received by GTN from a lawsuit settlement with a software supplier. The $54 million increase in comparable earnings in 2008 from 2007 was primarily due to a full year of earnings from ANR, the Alberta System rate settlement and higher earnings for the Canadian Mainline. Comparable earnings in 2006 were $529 million and excluded an $18 million bankruptcy settlement with Mirant and a $13 million gain on sale of TransCanada's general partner interest in Northern Border Partners, L.P. The increase in comparable earnings in 2007 compared to 2006 was primarily due to the acquisitions of ANR and additional interest in Great Lakes, higher earnings as a result of rate settlements for Canadian Mainline and the GTN System, and an increased ownership in PipeLines LP.

PIPELINES – FINANCIAL ANALYSIS

Canadian Mainline

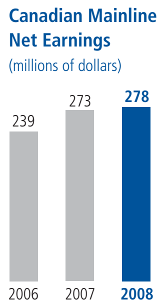
The Canadian Mainline is regulated by the NEB, which sets tolls that provide TransCanada with the opportunity to recover projected costs of transporting natural gas, including a return on the Canadian Mainline's average investment base. The NEB also approves new facilities before construction begins. Net earnings from the Canadian Mainline are affected by changes in the investment base, the rate of return on common equity (ROE), the level of deemed common equity and potential incentive earnings.

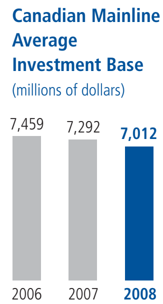
The Canadian Mainline currently operates under a five-year tolls settlement effective from 2007 to 2011. The cost of capital reflects an ROE as determined by the NEB's ROE formula on deemed common equity of 40 per cent. The remaining capital structure consists of short- and long-term debt, following the agreed upon redemption of the US$460 million 8.25 per cent Preferred Securities in 2007.

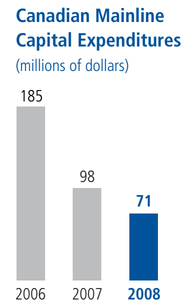
The settlement also established certain elements of the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. The variance between actual and agreed-upon OM&A costs accrues entirely to TransCanada from 2007 to 2009, and will be shared equally between TransCanada and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. The settlement also allows for performance-based incentive arrangements that the Company believes are mutually beneficial to both TransCanada and its customers.

Net earnings of $278 million in 2008 were $5 million higher than $273 million in 2007 primarily due to higher performance-based incentives earned and increased OM&A cost savings and an ROE of 8.71 per cent in 2008, as determined by the NEB, compared to 8.46 per cent in 2007. These increases were partially offset by a lower average investment base.

Net earnings of $273 million in 2007 were $34 million higher than $239 million in 2006. The increase primarily reflected the positive impact of the increase in deemed common equity ratio to 40 per cent from 36 per cent as a result of the Canadian Mainline tolls settlement, performance-based incentives earned and OM&A cost savings. These increases were partially offset by a lower allowed ROE of 8.46 per cent in 2007 (2006 – 8.88 per cent) and a lower average investment base.







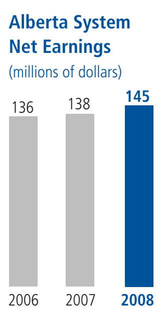
Alberta System

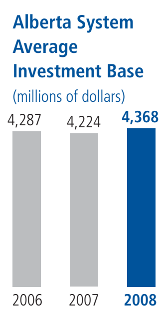
Construction and operation of the Alberta System's facilities and the terms and conditions of its services, including rates, are regulated by the AUC, primarily under the provisions of the *Gas Utilities Act (Alberta)* and the *Pipeline Act (Alberta)*.

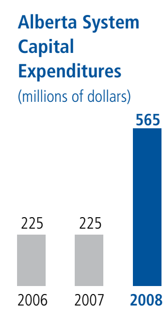
In December 2008, the AUC approved TransCanada's 2008-2009 Revenue Requirement Settlement Application, as discussed further in the "Pipelines – Opportunities and Developments" section of this MD&A.

The Alberta System's net earnings of $145 million in 2008 were $7 million higher than in 2007. The increase was due to the recognition of earnings related to the revenue requirement settlement. Earnings in 2007 reflected an ROE of 8.51 per cent on deemed common equity of 35 per cent.

Net earnings of $138 million in 2007 were $2 million higher than in 2006. The increase was primarily due to OM&A cost savings, partially offset by a lower allowed ROE and a lower investment base in 2007. The allowed ROE prescribed by the Alberta Energy and Utilities Board, the AUC's predecessor, was 8.51 per cent in 2007 compared with 8.93 per cent in 2006 on deemed common equity of 35 per cent.







ANR

TransCanada completed the acquisition of ANR in February 2007. The operations of ANR are regulated primarily by the U.S. Federal Energy Regulatory Commission (FERC). ANR provides natural gas transportation, storage and various capacity-related services to a variety of customers in both the U.S. and Canada. ANR's transmission system has a peak-day capacity of 6.8 billion cubic feet per day (Bcf/d). Due to the seasonal nature of its business, ANR's volumes and revenues are generally expected to be higher in the winter months. ANR also owns and operates 250 Bcf of underground natural gas storage facilities in Michigan. ANR's regulated natural gas storage and transportation services operate under current FERC-approved tariff rates. These tariffs include maximum and minimum rate levels for services and permit ANR to discount or negotiate rates on a non-discriminatory basis.

ANR Pipeline Company's (ANR Pipeline) rates were established pursuant to a settlement approved by the FERC effective November 1997. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC effective June 1990. None of ANR's FERC-regulated operations are required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a rate case.

Net income for 2008 was $132 million compared to $104 million for the period from the date of acquisition on February 22, 2007 to December 31, 2007. The increase in 2008 was primarily due to a full year of earnings in 2008 and increased revenues from new growth projects, partially offset by higher OM&A costs, including remediation expenditures for damage caused by Hurricane Ike.

GTN

Both of GTN's systems, the GTN System and North Baja (collectively, GTN), are subject to FERC-approved tariffs that establish maximum and minimum rates for various services. GTN's pipeline rates were established pursuant to a settlement approved by the FERC in January 2008, and these rates became effective January 1, 2007. Under the settlement, a five-year moratorium was established during which the GTN System and the settling parties are prohibited under the *Natural Gas Act of 1938* from taking certain actions, including any filings to adjust rates. The settlement also requires the GTN System to file a rate case within seven years of the effective date. The systems are permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's earnings are affected by variations in contracted volume levels, volumes delivered and prices charged under the various service types, as well as by variations in the costs of providing services.

GTN's comparable earnings were $65 million in 2008, an increase of $7 million compared to 2007 primarily due to decreased OM&A expenses. An increase in revenues for North Baja was offset by a decrease in revenues for the GTN System.

Comparable earnings were $58 million in 2007, a $12 million increase from 2006. The increase was primarily due to the positive impact of the rate case settlement in 2007, partially offset by lower long-term firm contracted volumes, a higher provision taken for non-payment of contract revenues from Calpine and a weaker U.S. dollar in 2007.

Other Pipelines

TransCanada's direct and indirect investments in various natural gas pipelines and its project development activities relating to natural gas and oil transmission opportunities throughout North America are included in Other Pipelines.

TransCanada's comparable earnings from Other Pipelines were $96 million in 2008 compared to $87 million in 2007. The increase was primarily due to lower general, administrative and support costs, and higher earnings from PipeLines LP, Tamazunchale and Iroquois, partially offset by lower earnings from Gas Pacifico/INNERGY, TransGas, Portland and Great Lakes.

Comparable earnings from Other Pipelines were $87 million in 2007, a $6 million increase compared to 2006. The increase was primarily due to higher PipeLines LP earnings resulting from TransCanada's increased ownership interests in PipeLines LP and Great Lakes, and a full year of earnings in 2007 from Tamazunchale. These increases were partially offset by higher project development and support costs associated with growing the Pipelines business, the effects of a weaker U.S. dollar in 2007 and proceeds of a bankruptcy settlement received by Portland in 2006.

At December 31, 2008, Other Assets included $74 million and $42 million for capitalized costs related to the Keystone expansion to the U.S. Gulf Coast and the Bison pipeline project, respectively.

PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Keystone

Keystone is expected to deliver crude oil from Hardisty, Alberta, to U.S. Midwest markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma.

In March 2008, the U.S. Department of State issued a Presidential Permit to Keystone authorizing construction, maintenance and operations of facilities at the U.S./Canada border for the transportation of crude oil between the two countries. Construction of Keystone began in May 2008 in both Canada and the U.S. Commissioning of the Wood River and Patoka segment is expected to commence in late 2009 with commercial operations to follow in early 2010. Commissioning of the Cushing segment is expected to commence in late 2010.

In June 2008, Keystone received approval from the NEB to add new pumping facilities to accommodate an increase to approximately 590,000 Bbl/d from 435,000 Bbl/d in volumes to be delivered to the Cushing markets.

After an open season conducted during third quarter 2008, Keystone secured additional firm, long-term contracts totaling 380,000 Bbl/d for an average term of approximately 17 years. With these shipper commitments, Keystone will proceed with the necessary regulatory applications in Canada and the U.S. for approvals to construct and operate an expansion of the pipeline system that will provide additional capacity from Western Canada to the U.S. Gulf Coast in 2012 and will increase the total commercial capacity of Keystone to approximately 1.1 million Bbl/d. With the additional contracts, Keystone now has secured long-term commitments for 910,000 Bbl/d for an average term of approximately 18 years. This includes commitments made by shippers to sign transportation service agreements for 35,000 Bbl/d of capacity in an open season to be held in 2009. The commitments represent approximately 83 per cent of the commercial design of the system.

The entire Keystone project is currently expected to cost approximately US$12 billion between 2008 and 2012. In 2008, the Keystone partnerships made capital expenditures of approximately $1.7 billion on the entire project, of which $1.0 billion was contributed by TransCanada.

TransCanada has agreed to increase its equity ownership in the Keystone partnerships up to 79.99 per cent from 50 per cent with ConocoPhillips' equity ownership being reduced concurrently to 20.01 per cent. In accordance with this agreement, TransCanada will fund 100 per cent of the construction expenditures until the participants' project capital contributions are aligned with the revised ownership interests. At December 31, 2008, TransCanada's equity ownership in the Keystone partnerships was approximately 62 per cent. Certain parties that have made volume commitments to the Keystone expansion have an option to acquire up to a combined 15 per cent equity ownership in the Keystone partnerships by the end of first quarter 2009. If all of the options are exercised, TransCanada's equity ownership would be reduced to 64.99 per cent.

Keystone's tolls, tariffs and facilities are regulated by the NEB in Canada and the FERC in the U.S., and have been approved for the segments shipping to Wood River, Patoka and Cushing. The Company expects the tolls and tariffs to remain in place for the term of the initial shipper contracts, which comprise approximately 83 per cent of Keystone's commercial capacity.

Canadian Mainline

In December 2008, the NEB announced that, pursuant to its formula, the 2009 allowed ROE for NEB-regulated pipelines, including the Canadian Mainline, will be 8.57 per cent, a decrease from 8.71 per cent in 2008.

Alberta System

In December 2008, the AUC approved the Alberta System's 2008-2009 Revenue Requirement Settlement Application. As part of the settlement, fixed costs were established for ROE, income taxes and OM&A costs. Any variances between actual costs and those agreed to in the settlement accrue to TransCanada, subject to an ROE and income tax adjustment mechanism, which accounts for variances between actual and settlement rate base, and income tax assumptions. The other cost elements of the settlement are treated on a flow-through basis.

In November 2008, an NEB hearing concluded on TransCanada's application to establish Federal jurisdiction over the Alberta System. A decision is expected from the NEB at the end of February 2009. Changing from AUC to NEB jurisdiction will allow the expansion of the Alberta System beyond Alberta provincial borders.

In October 2008, the AUC approved TransCanada's application for a permit to construct the North Central Corridor expansion at a cost of approximately $925 million. The expansion comprises a 300 km (186 miles) natural gas pipeline and associated compression facilities on the northern section of the Alberta System.

On September 8, 2008, TransCanada reached a proposed agreement with Canadian Utilities Limited (ATCO Pipelines) to provide seamless natural gas transmission service to customers. If approved by regulatory authorities, the arrangement will see the two companies combine physical assets under a single rates and services structure with a single commercial interface for customers but with each company separately managing assets within distinct operating territories in the province. TransCanada continues to work with all stakeholders to finalize this agreement.

In February 2008, the AUC initiated a Generic Cost of Capital proceeding to review the generic ROE and capital structures of AUC regulated utilities. In November 2008, TransCanada filed an application requesting an 11 per cent ROE on 40 per cent deemed common equity for the Alberta System in 2009. The hearing is scheduled to begin on May 19, 2009.

ANR

In 2008, ANR completed its STEP 2008 project, which added 14 Bcf of storage and 200 million cubic feet per day (mmcf/d) of withdrawal capacity to the Cold Springs 1 storage field located in Northern Michigan, and increased ANR's total storage capacity to 250 Bcf. The project was completed under budget and service was provided on schedule. Supply on ANR's southwest leg was increased as a result of an interconnect with the Rockies Express natural gas pipeline, which commenced service in January 2008. There is strong potential for new supply on the southeast leg from shale gas in the mid-continent region, and another interconnect with the Rockies Express pipeline is planned for the southeast leg in Indiana in mid-2009. ANR is also pursuing other supply additions on both its southwest and southeast legs.

In September 2008, certain portions of the Company's Gulf of Mexico offshore facilities were impacted by Hurricane Ike. The Company estimates its total exposure to damage costs to be approximately US$30 million to US$40 million, mainly to replace, repair and abandon capital assets, including the estimated cost to abandon an offshore platform. At December 31, 2008, capital expenditures of US$2 million and OM&A costs of US$6 million had been incurred. The remaining costs are primarily expected to be capital expenditures. Service on the majority of the offshore facilities has been restored and related throughput volumes have returned to near pre-hurricane levels. The timing of the remaining facilities' return to service is primarily dependent upon decisions to be made by upstream producers regarding their damaged facilities in the Gulf of Mexico.

Palomar

In December 2008, Palomar Gas Transmission LLC filed with the FERC for a certificate to build a pipeline extending from the GTN System in central Oregon, to the Columbia River northwest of Portland. The proposed pipeline is expected to be capable of transporting up to 1.3 Bcf/d of natural gas. The project is a 50/50 joint venture of GTN and Northwest Natural Gas Co.

North Baja

In September 2008, the FERC approved North Baja's application to build a natural gas pipeline to serve the Yucca Power Plant owned by Arizona Public Service Company. Three miles of the proposed pipeline are expected to be in the U.S. and owned by North Baja, and another three miles in Mexico are owned by Gasoducto Bajanorte. Pending final approval by the U.S. Government, construction is expected to commence in first quarter 2009 with a projected in-service date of May 2009.

Portland

On April 1, 2008, Portland filed a general rate case with the FERC proposing a rate increase of approximately six per cent as well as other changes to its tariffs. In accordance with a FERC order dated May 1, 2008, the proposed tariffs went into effect on September 1, 2008, subject to refund. The hearing is scheduled to begin on July 13, 2009.

TQM

In December 2008, the NEB concluded a proceeding with respect to TQM's Cost of Capital application for 2007 and 2008. The application sought an ROE of 11 per cent on deemed equity of 40 per cent. The proceeding also provided an opportunity for TQM to propose alternatives to the current ROE formula. A decision from the NEB is expected in first quarter 2009.

U.S. Rockies Pipeline Projects

The Bison pipeline project is a proposed pipeline from the Powder River Basin in Wyoming to the Northern Border system in North Dakota. The project has shipping commitments for approximately 405 mmcf/d and is expected to be in service in fourth quarter 2010. The capital cost of the Bison pipeline project is estimated at US$500 million to US$600 million. TransCanada continues to work with Bison shippers to finalize the size and design of this project.

In addition, TransCanada is proposing the Pathfinder pipeline project, a 1,006 km (625 miles) pipeline from Meeker, Colorado to the Northern Border system in North Dakota. A portion of the Pathfinder pipeline may share a common route with the Bison pipeline and may also share some common facilities. TransCanada continues to work with prospective Pathfinder shippers to advance this project.

TransCanada and Williams Gas Pipeline Company, LLC (Williams) are evaluating the development of the Sunstone pipeline, a proposed pipeline from Wyoming to Stanfield, Oregon. This project would provide Pacific Northwest and California markets with access to incremental Rockies supply. TransCanada and its partner continue to work with customers to determine the appropriate size, time and route for this project.

Mackenzie Gas Pipeline Project

The MGP is a proposed 1,200 km (746 miles) natural gas pipeline to be constructed from a point near Inuvik, Northwest Territories to the northern border of Alberta, where it is expected to connect to the Alberta System.

TransCanada's involvement with the MGP arises from a 2003 agreement between the Mackenzie Valley Aboriginal Pipeline Group (APG) and the MGP, whereby TransCanada agreed to finance the APG's one-third share of the pre-development costs associated with the project. Cumulative advances made by TransCanada totaled $140 million at December 31, 2008 and are included in Other Assets. These amounts constitute a loan to the APG, which becomes repayable only after the natural gas pipeline commences commercial operations. The total amount of the loan is expected to form part of the rate base of the pipeline and to subsequently be repaid from the APG's share of future natural gas pipeline revenues or from alternate financing. If the project does not proceed, TransCanada has no recourse against the APG for recovery of advances made. Accordingly, TransCanada's ability to recover its investment through loan repayments and/or equity ownership in the project depends upon a successful outcome of the project.

Under the terms of certain MGP agreements, TransCanada holds an option to acquire up to a five per cent equity ownership in the natural gas pipeline at the time of the decision to construct it. In addition, TransCanada gains certain rights of first refusal to acquire 50 per cent of any divestitures by existing partners and an entitlement to obtain a one-third interest in all expansion opportunities once the APG reaches a one-third ownership share, with the other natural gas pipeline owners and the APG sharing the balance.

TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. Project timing continues to be uncertain. Detailed discussions with the Canadian government have taken place and have resulted in a proposal in January 2009 from the government to the MGP. The co-venture group is considering the proposal and is expected to respond to the government in the near future. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TransCanada, this may result in a reassessment of the carrying amount of the APG advances.

Alaska Pipeline Project

In November 2007, TransCanada submitted an application to the State of Alaska for a license to construct the Alaska Pipeline Project under the AGIA. In January 2008, Alaska Governor Sarah Palin's administration determined that TransCanada's application was the only proposal that met all of the state's requirements and in December 2008 the State of Alaska issued the AGIA license to TransCanada. Under the AGIA, the State of Alaska has agreed to reimburse a share of TransCanada's eligible pre-construction costs to a maximum of US$500 million.

The Alaska Pipeline Project will be a 4.5 Bcf/d natural gas pipeline extending approximately 2,760 km (1,715 miles) from a new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta. This pipeline will integrate with the Alberta System to provide access to diverse markets across North America. The application included provision for expansions up to 5.9 Bcf/d through the addition of compressor stations in Alaska and Canada. TransCanada estimated the total capital cost of the entire project to be approximately US$26 billion in 2007 dollars.

Since the AGIA license was awarded, TransCanada has moved forward with developing the project, which involves engineering, environmental, aboriginal relations and commercial work to conclude an initial binding open season by mid-2010. TransCanada continues its efforts to align with potential shippers and if sufficient firm contracts are secured in the open season, construction would begin following regulatory approvals, with an anticipated in-service date of 2018.

PIPELINES – BUSINESS RISKS

Supply, Markets and Competition

TransCanada faces competition at both the supply and market ends of its systems. This competition comes from other natural gas pipelines accessing the increasingly mature WCSB and markets served by TransCanada's pipelines. In addition, the continued expiration of long-term firm contracts has resulted in significant reductions in long-term firm contracted capacity and shifts to short-term firm and interruptible contracts on the Canadian Mainline, the Alberta System, Foothills and the GTN System.

In 2008, the gas supply environment changed. Production out of the WCSB declined while supply in the U.S. grew. Previously it had been expected that U.S. supply would decline. Furthermore, with lower natural gas prices, lower cost U.S. gas developments may hinder the further development of WCSB gas supplies.

TransCanada's primary source of natural gas supply is the WCSB. The WCSB has remaining discovered natural gas reserves of approximately 57 trillion cubic feet and a reserves-to-production ratio of approximately nine years at current levels of production. Historically, sufficient additional reserves have been discovered on an ongoing basis to maintain the reserves-to-production ratio at close to nine years, however, supply from the WCSB has declined in recent years due to a continued reduction in levels of drilling activity in the basin. The reduced drilling activity is a result of lower prices, higher supply costs, which include higher royalties in Alberta, and competition for capital from other North American basins that have lower exploration costs. Drilling levels in the WCSB are expected to reach a low point in 2009 and then should begin to recover in the ensuing years assuming that gas prices stabilize at $6 to $7 per gigajoule (GJ) and that finding and development costs become more economical. TransCanada anticipates there will be excess natural gas pipeline capacity out of the WCSB in the foreseeable future as a result of capacity expansions on its wholly owned and partially owned natural gas pipelines over the past decade, competition from other pipelines, and significant growth in natural gas demand within Alberta driven by oil sands and electricity generation requirements.

TransCanada's Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas processing plants in Alberta to domestic and export markets. Despite reduced overall drilling levels, activity remains robust in certain areas of the WCSB, which has resulted in the need for new transmission infrastructure. The primary areas of high activity have been deeper conventional drilling in western Alberta and in the foothills region of B.C., and coalbed methane development in central Alberta. Recently, shale gas production in B.C. has emerged as a potentially significant natural gas supply source.

Historically, TransCanada's eastern natural gas pipeline system has been supplied by long-haul flows from the WCSB and by short-haul volumes received from storage fields and interconnecting pipelines in southwestern Ontario. Over the last few years, the Canadian Mainline has experienced reductions in long-haul flows, which have been partially offset by increases in short-haul volumes, resulting in an increase in Canadian Mainline tolls.

Demand for natural gas in TransCanada's key eastern markets, which are served by the Canadian Mainline, is expected to continue to increase, particularly to meet the expected growth in natural gas-fired power generation. However, the Company believes the current environment could reverse this trend in the short term given sufficient levels of erosion of market demand. Although there are opportunities to increase market share in Canadian domestic and U.S. export markets, TransCanada faces significant competition in these regions. Consumers in the northeastern U.S. generally have access to an array of natural gas pipeline and supply options. Eastern markets that historically received Canadian supplies only from TransCanada are now capable of receiving supplies from new natural gas pipelines that source U.S. and Atlantic Canadian supplies.

The source of oil supply for Keystone is located primarily in Alberta, which produces approximately 79 per cent of the oil in the WCSB. In 2008, the WCSB produced a total of approximately 2.4 million Bbl/d, comprised of 1.2 million Bbl/d of conventional crude oil and condensate, and 1.2 million Bbl/d of oil from the oil sands area of Alberta. The production of conventional oil has been declining but has been offset by increases in production of oil from the Alberta oil sands. The Alberta Energy Resources Conservation Board has estimated that there are 173 billion barrels of remaining established reserves in the Alberta oil sands.

A decline in oil prices in late 2008 has resulted in announcements of delays in oil sands projects and upgraders, however, in December 2008, the Canadian Association of Petroleum Producers forecast WCSB oil supply would increase from 2.4 million Bbl/d in 2008 to 3.5 million Bbl/d by 2015 and 4.1 million Bbl/d by 2020.

Keystone has 910,000 Bbl/d of contracts for capacity, on a ship or pay basis, with an average contract life of 18 years, which the Company believes will provide incentive for contract shippers to ship on Keystone. However, Keystone must compete for spot throughput with other oil pipelines from Alberta.

Keystone's markets for crude oil are refiners in the U.S. Midwest and Gulf Coast regions. A competing pipeline can also deliver WCSB crude oil to the Midwest markets supplied by Keystone. Currently, competing pipelines can deliver oil to the U.S. Gulf Coast, through interconnections with other pipelines. Keystone must also compete with U.S. domestically produced oil and imported oil for markets in the Midwest and Gulf Coast regions.

ANR's natural gas supply is primarily sourced from the Gulf of Mexico and mid-continent U.S. regions, which are also served by competing natural gas pipelines. ANR also has competition from other natural gas pipelines and storage operations in its primary markets in the U.S. Midwest. The Gulf of Mexico region is extremely competitive given its extensive natural gas pipeline network. ANR is one of many interstate and intrastate pipelines in the region competing for new and existing production as well as for new supplies from shale production in the mid-continent, from the Rockies Express natural gas pipeline originating in the Rocky Mountain region, and from LNG. Several new natural gas pipelines are proposed or under construction to connect new supplies to the numerous pipelines in the Gulf of Mexico region. ANR competes with other natural gas pipelines in the region to attract supply to its pipeline for alternative markets and storage. In addition to pipeline competition for market and supply, current difficult economic conditions are expected to reduce energy demand and may put future ANR capacity renewals at risk as the North American economy slows or potentially contracts in key markets in the upper U.S. Midwest. As lower natural gas prices reduce drilling activity, the supply growth that has been fuelling the growth in pipeline infrastructure in the mid-continent could slow down but is still expected to exceed demand requirements in the near term. These factors could negatively affect pipeline capacity value as transportation capacity becomes more abundant.

The GTN System must compete with other pipelines to access natural gas supplies and markets. Transportation service capacity on the GTN System provides customers in the U.S. Pacific Northwest, California and Nevada with access to supplies of natural gas primarily from the WCSB. These three markets may also access supplies from other basins. In the Pacific Northwest market, natural gas transported on the GTN System competes with the Rocky Mountain natural gas supply and with additional western Canadian supply transported by other pipelines. Historically, natural gas supplies from the WCSB have been competitively priced in relation to supplies from the other regions serving these markets. The GTN System has experienced significant contract non-renewals since 2005 as the natural gas it transports from the WCSB competes for the California and Nevada markets against supplies from the Rocky Mountain and southwestern U.S. basins. Recently, Pacific Gas and Electric Company, the GTN System's largest customer, received California Public Utilities Commission approval to commit to capacity on a proposed competing project out of the Rocky Mountain basin to the California border.

Regulatory Financial Risk

Regulatory decisions continue to have a significant impact on the financial returns from existing investments in TransCanada's Canadian wholly owned pipelines and are expected to have a similarly significant impact on financial returns from future investments. TransCanada remains concerned that current financial returns approved by regulators are not as competitive as returns from other assets with similar risk profiles. In recent years, TransCanada applied to the NEB and the AUC for an ROE of 11 per cent on 40 per cent deemed common equity for both the Canadian Mainline and the Alberta System. The NEB has reaffirmed its ROE formula and the AUC has established a generic ROE that is largely aligned with the NEB formula. Through rate applications and negotiated settlements, TransCanada has been able to improve the common equity components of its Canadian wholly owned pipeline capital structures, but there is no assurance that this success can be repeated.

Most recently, TransCanada has continued to address concerns about financial returns on the Alberta System in the AUC's 2009 Generic Cost of Capital Proceeding. In November 2008, TransCanada filed an application requesting an ROE of 11 per cent on 40 per cent deemed common equity for the Alberta System. TQM filed an application with the NEB in December 2007 requesting a fair return on capital, consisting of an ROE of 11 per cent on 40 per cent deemed common equity. The outcome of these proceedings may influence the regulators' view of fair financial returns on equity associated with TransCanada's other Canadian wholly owned pipelines.

Throughput Risk

As transportation contracts expire, TransCanada's U.S. natural gas pipelines are expected to become more exposed to the risk of reduced throughput and their revenues more likely to experience increased variability. Throughput risk is created by supply and market competition, gas basin pricing, economic activity, weather variability, natural gas pipeline competition and pricing of alternative fuels.

Execution and Capital Cost Risk

Capital costs related to the construction of Keystone are subject to a capital cost risk- and reward-sharing mechanism with its customers. This mechanism allows Keystone to adjust its tolls by a factor based on the percentage change in the capital cost of the project. Tolls for the portion of Keystone to Wood River, Patoka and Cushing will be adjusted by a factor equal to 50 per cent of the percentage change in capital cost. Tolls on the expansion to the U.S. Gulf Coast will be adjusted by a factor equal to 75 per cent of the percentage change in capital cost.

Refer to the "Risk Management and Financial Instruments" section of this MD&A for information on managing risks in the Pipelines business.

PIPELINES – OUTLOOK

TransCanada assumes that its operations in 2009 will be materially consistent with those in 2008 except for the impact of those factors discussed in this section.

Although demand for natural gas and crude oil has declined and is expected to further decline in North America in 2009 due to the current economic downturn, the Company expects demand to increase in the long term. TransCanada's Pipelines business will continue to focus on the delivery of natural gas to growing markets, connecting new supply, progressing development of new infrastructure to connect natural gas from the north and unconventional supplies such as shale gas, coalbed methane and LNG, and construction and expansion of Keystone.

TransCanada expects producers will continue to explore and develop new fields in Western Canada, particularly in northeastern B.C. and the west and central foothills regions of Alberta. There is also expected to be significant exploration and development activity aimed at unconventional resources such as coalbed methane and shale gas.

In 2008, TransCanada filed an application with the NEB to establish federal jurisdiction for the Alberta System. If the application is approved, the Alberta System will switch from AUC regulation to NEB regulation, allowing it to construct and operate pipeline extensions into other provinces and allowing it to provide direct integrated Alberta System natural gas transmission service to gas production locations outside of Alberta. Extensions of the Alberta System beyond Alberta's borders are currently prohibited under provincial regulation. An NEB jurisdiction decision is expected in first quarter 2009.

Most of TransCanada's current expansion plans in Canadian natural gas transmission are focused on the Alberta System. TransCanada recently concluded a binding open season process for natural gas transmission service for the Montney shale gas region located in northeastern B.C. Five shippers have committed to firm gas transportation contracts on the Groundbirch pipeline that will serve the Montney region. Volumes associated with these commitments will reach 1.1 Bcf/d by 2014. The Groundbirch pipeline is expected to commence service in fourth quarter 2010, subject to receipt of necessary approvals.

In addition, TransCanada is finalizing details associated with a binding open season and pipeline extension project to service the Horn River shale gas region located in northeastern B.C. Five shippers have committed to firm gas transportation contracts for a total volume of 378 mmcf/d by second quarter 2012. Subject to concluding a successful binding open season, the Horn River project is expected to commence operation in second quarter 2011, subject to receipt of necessary approvals.

Both the Groundbirch and Horn River projects are proposed as extensions to the Alberta System, which will provide B.C. producers with direct integrated gas transmission service from receipt points in B.C. These pipeline projects will increase netbacks to producers and increase the throughput on the Alberta System and on its downstream pipelines that serve markets located throughout North America, as well as increase usage of the Nova Inventory Transfer commercial hub that is used by buyers and sellers of natural gas throughout North America.

In addition to extensions into B.C., new facilities are required to expand the integrated Alberta System in response to changes in the distribution of supply and in markets across the Alberta System.

In the U.S., TransCanada expects unconventional production will continue to be developed from shale gas reservoirs in east Texas, northwest Louisiana, Arkansas, and southwest Oklahoma. Supplies from coalbed methane and tight gas sands in the Rocky Mountain region are also expected to grow. Additionally, in the medium to long term, some level of incremental supply is anticipated from LNG imports into the U.S., particularly in the summer months. The resulting growth in supply will provide additional commercial opportunities for TransCanada. In particular, the southwest leg of ANR is expected to continue to remain fully subscribed for the foreseeable future, and new transport routes are being developed to move the additional Rocky Mountain and shale gas production to midwestern and eastern U.S. markets, including interconnections with ANR. As mid-continent supplies develop, the southeast leg of ANR has capacity to transport additional volumes of Rocky Mountain and mid-continent shale production, as well as LNG.

Producers continue to develop new oil supply in Western Canada. There are several new oil sands projects under construction that will begin production in 2009 and 2010. By 2015, oil sands production is expected to double from 1.2 million Bbl/d in 2008 and total Western Canada oil supply is projected to grow over the same period to approximately 3.5 million Bbl/d from 2.4 million Bbl/d. The primary market for new oil production extends from the U.S. Midwest to the U.S. Gulf Coast and contains a large number of refineries that are well equipped to handle Canadian light and heavy crude oil blends. Incremental western Canadian crude oil production is expected to replace declining U.S. imports of crude oil from other countries.

This increase in WCSB crude oil exports requires new pipeline capacity, including Keystone and further expansions to the U.S. Gulf Coast. TransCanada will continue to pursue additional opportunities to move crude oil from Alberta to U.S. markets.

TransCanada will continue to focus on operational excellence and on collaborative efforts with all stakeholders to achieve negotiated settlements and service options that will increase the value of the Company's business to customers and shareholders.

Earnings

The Company expects continued growth on its Alberta System. The Company also anticipates a modest level of investment in its other existing Canadian natural gas pipelines, resulting in an expected continued net decline in the average investment base due to annual depreciation. A net decline in the average investment base has the effect of reducing year-over-year earnings from these assets. Under the current regulatory model, earnings from Canadian pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contract levels.

Reduced firm transportation contract volumes due to customer defaults, lower supply available for export from the WCSB and expiry of long-term contracts could have a negative impact on short-term earnings from TransCanada's U.S. natural gas pipelines, unless the available capacity can be recontracted. The ability to recontract available capacity is influenced by prevailing market conditions and competitive factors, including competing natural gas pipelines and supply from other natural gas sources in markets served by TransCanada's U.S. pipelines. Earnings from Pipelines' foreign operations are also impacted by changes in foreign currency exchange rates.

Capital Expenditures

Total capital spending for all pipelines in 2008 was $1.8 billion. Capital spending for the wholly owned pipelines in 2009 is expected to be approximately $1.1 billion. In addition, capital spending for TransCanada's share of constructing Keystone is expected to be approximately $3.6 billion in 2009.

NATURAL GAS THROUGHPUT VOLUMES
(Bcf)

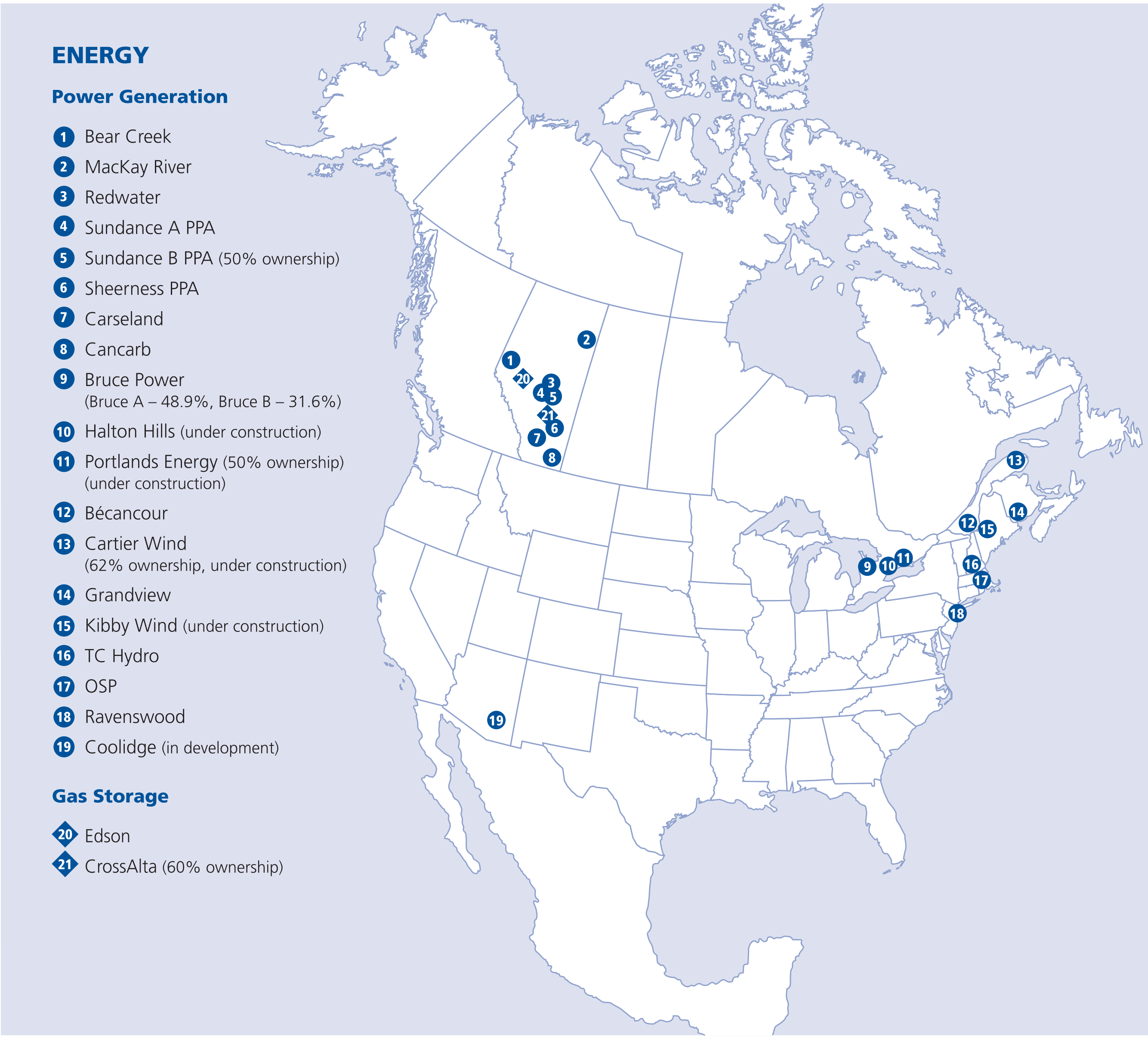
	2008	2007	2006
Canadian Mainline(1)	**3,467**	3,183	2,955
Alberta System(2)	**3,800**	4,020	4,051
ANR(3)	**1,655**	1,210	n/a
GTN System	**783**	827	790
Foothills	**1,292**	1,441	1,403
North Baja	**104**	90	95
Great Lakes	**784**	829	816
Northern Border	**731**	800	799
Iroquois	**376**	394	384
TQM	**170**	207	158
Ventures LP	**165**	178	179
Gas Pacifico	**73**	71	52
Portland	**50**	58	52
Tamazunchale(4)	**53**	29	n/a
Tuscarora	**30**	28	28
TransGas	**26**	24	22

(1) Canadian Mainline physical receipts originating at the Alberta border and in Saskatchewan in 2008 were 1,898 Bcf (2007 – 2,090 Bcf; 2006 – 2,207 Bcf).

(2) Field receipt volumes for the Alberta System in 2008 were 3,843 Bcf (2007 – 4,047 Bcf; 2006 – 4,160 Bcf).

(3) ANR's results include delivery volumes from the date of acquisition of February 22, 2007.

(4) Tamazunchale's results include volumes since December 1, 2006.



BEAR CREEK An 80 MW natural gas-fired cogeneration plant, Bear Creek is located near Grande Prairie, Alberta.

MACKAY RIVER A 165 MW natural gas-fired cogeneration plant, MacKay River is located near Fort McMurray, Alberta.

REDWATER A 40 MW natural gas-fired cogeneration plant, Redwater is located near Redwater, Alberta.

SUNDANCE A&B TransCanada has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generating facility under a PPA, which expires in 2017. TransCanada also has the rights to 50 per cent of the generating capacity of the 706 MW Sundance B facility under a PPA that expires in 2020. The Sundance facilities are located in south-central Alberta.

SHEERNESS TransCanada has the rights to 756 MW of generating capacity from the Sheerness coal-fired plant under a PPA, which expires in 2020. The Sheerness plant is located in southeastern Alberta.

CARSELAND An 80 MW natural gas-fired cogeneration plant, Carseland is located near Carseland, Alberta.

CANCARB A 27 MW facility fuelled by waste heat from TransCanada's adjacent thermal carbon black (a natural gas by-product) facility, Cancarb is located in Medicine Hat, Alberta.

BRUCE POWER Bruce Power is a nuclear generating facility located northwest of Toronto, Ontario. TransCanada owns 48.9 per cent of Bruce A, which has four 750 MW reactors, two of which are currently being refurbished and are expected to restart in 2010. TransCanada owns 31.6 per cent of Bruce B, which has four operating reactors with a combined capacity of approximately 3,200 MW.

HALTON HILLS A 683 MW natural gas-fired power plant, Halton Hills is under construction near the town of Halton Hills, Ontario, and is expected to be in service in third quarter 2010.

PORTLANDS ENERGY A 550 MW high-efficiency, combined-cycle natural gas generation power plant, Portlands Energy is under construction near the downtown area of Toronto, Ontario. The plant is 50 per cent owned by TransCanada and is expected to be commissioned in its combined-cycle mode in first quarter 2009.

BÉCANCOUR A 550 MW natural gas-fired cogeneration power plant, Bécancour is located near Trois-Rivières, Québec.

CARTIER WIND The 740 MW Cartier Wind farm consists of six wind power projects located in Québec. Cartier Wind is 62 per cent owned by TransCanada. Three of the projects, Baie-des-Sables, Anse-á-Valleau and Carleton have generating capacities of 110 MW, 101 MW and 109 MW, respectively. Planning and construction of the remaining three projects will continue, subject to future approvals.

GRANDVIEW A 90 MW natural gas-fired cogeneration power plant, Grandview is located in Saint John, New Brunswick.

KIBBY WIND The 132 MW Kibby Wind power project is under construction and will include 44 turbines located in Kibby and Skinner Townships in Maine. Construction began in July 2008 and commissioning of the first phase is expected to begin in fourth quarter 2009.

TC HYDRO With a total generating capacity of 583 MW, TC Hydro comprises 13 hydroelectric facilities, including stations and associated dams and reservoirs, on the Connecticut and Deerfield rivers in New Hampshire, Vermont and Massachusetts.

OSP A 560 MW natural gas-fired, combined-cycle facility, OSP is located in Burrillville, Rhode Island.

RAVENSWOOD In August 2008, TransCanada acquired the 2,480 MW multiple unit generating facility in Queens, New York employing dual-fuel capable steam turbine, combined cycle and combustion turbine technology.

COOLIDGE A 575 MW simple-cycle, natural gas-fired peaking power generation station, Coolidge is under development in Coolidge, Arizona. Detailed engineering, geotechnical and regulatory work began in 2008 and commissioning of the facility is expected in 2011.

EDSON An underground natural gas storage facility, Edson is connected to the Alberta System near Edson, Alberta. The facility's central processing system is capable of maximum injection and withdrawal rates of 725 mmcf/d of natural gas. Edson has a working natural gas storage capacity of approximately 50 Bcf.

CROSSALTA An underground natural gas storage facility, CrossAlta is connected to the Alberta System and is located near Crossfield, Alberta. TransCanada owns 60 per cent of CrossAlta, which has a working natural gas capacity of 54 Bcf with a maximum capability of delivering 480 mmcf/d.

ENERGY – HIGHLIGHTS

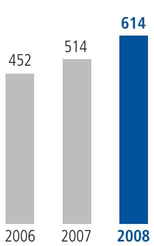
- Energy's net earnings were $614 million in 2008, an increase of $100 million from $514 million in 2007. Energy's comparable earnings were $641 million in 2008, an increase of $182 million from $459 million in 2007.
- In August 2008, TransCanada acquired the 2,480 MW Ravenswood facility in Queens, New York for US$2.9 billion, subject to certain post-closing adjustments.
- Approximately 2,700 MW of additional generation capacity was under construction at December 31, 2008, with an anticipated capital cost of $5 billion.
- Since 1999, the nominal generating capacity of TransCanada's Energy business has increased by approximately 7,800 MW, representing an investment of approximately $7 billion to the end of 2008, with an additional 2,700 MW currently under development and construction.

ENERGY RESULTS
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Western Power	**426**	308	297
Eastern Power	**338**	255	187
Bruce Power	**201**	167	235
Natural Gas Storage	**135**	136	93
General, administrative, support costs and other	**(168)**	(158)	(144)
Operating income	**932**	708	668
Financial charges	**(23)**	(22)	(23)
Interest income and other	**6**	10	5
Income taxes	**(274)**	(237)	(221)
Comparable Earnings(1)	**641**	459	429
Writedown of Broadwater costs	**(27)**	–	–
Gain on sale of land	**–**	14	–
Fair value adjustments of natural gas storage inventory and forward contracts	**–**	7	–
Income tax adjustments	**–**	34	23
Net Earnings	**614**	514	452

(1) Refer to the "Non-GAAP Measures" section of this MD&A for further discussion of comparable earnings.

Energy Net Earnings
(millions of dollars)



Energy's net earnings in 2008 of $614 million increased $100 million compared to $514 million in 2007. Comparable earnings of $641 million in 2008 increased $182 million compared to 2007 and excluded a $27 million writedown of costs previously capitalized for Broadwater. The increases in comparable and net earnings were due to higher operating income in Western Power, Eastern Power and Bruce Power. Comparable earnings of $459 million for 2007 excluded net unrealized gains of $7 million resulting from changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts, a $14 million gain on sale of land and $34 million of favourable income tax adjustments.

Energy's net earnings in 2007 were $514 million compared to $452 million in 2006. Comparable earnings were $459 million in 2007, an increase of $30 million from 2006. The increase was due to higher operating income in Eastern Power, Natural Gas Storage and Western Power, partially offset by a reduced contribution from Bruce Power. Comparable earnings excluded net unrealized gains of $7 million resulting from natural gas storage fair value changes, a $14 million gain on sale of land, $34 million of favourable income tax adjustments in 2007 as well as a $23 million favourable impact in 2006 from future income taxes as a result of reductions in Canadian federal and provincial corporate income tax rates.

POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Western Power		
Sheerness	756	Coal
Coolidge[1]	575	Natural gas
Sundance A	560	Coal
Sundance B[2]	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,636	
Eastern Power		
Ravenswood[3]	2,480	Natural gas/oil
Halton Hills[1]	683	Natural gas
TC Hydro	583	Hydro
OSP	560	Natural gas
Bécancour	550	Natural gas
Cartier Wind[4]	458	Wind
Portlands Energy[5]	275	Natural gas
Kibby Wind[1]	132	Wind
Grandview	90	Natural gas
	5,811	
Bruce Power[6]	2,480	Nuclear
Total nominal generating capacity[1]	10,927	

(1) Halton Hills and Kibby Wind are currently under construction. Coolidge is currently under development.

(2) Represents TransCanada's 50 per cent share of the Sundance B power plant output.

(3) Acquired in third quarter 2008.

(4) Represents TransCanada's 62 per cent share of the total 740 MW project. Three of six wind farms were placed in service, one in November 2008, one in November 2007 and the other in November 2006, with a combined generating capacity of 320 MW.

(5) Represents TransCanada's 50 per cent share of this 550 MW facility, which is currently under construction.

(6) Represents TransCanada's 48.9 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B.

ENERGY – FINANCIAL ANALYSIS

Western Power

As at December 31, 2008, Western Power owns or has the rights to approximately 2,600 MW of power supply in Alberta and the western U.S. from its three long-term power purchase arrangements (PPA), six natural gas-fired cogeneration facilities and a peaking facility under development in Arizona. The power supply portfolio of Western Power in Alberta comprises approximately 1,700 MW of low-cost, base-load coal-fired generation supply through the three long-term PPAs and approximately 400 MW of natural gas-fired cogeneration assets. This supply portfolio includes some of the lowest cost, most competitive generation in the Alberta market area. The Sheerness and Sundance B PPAs have remaining terms of 12 years, while the Sundance A PPA has a remaining term of nine years. In 2008, the Salt River Project Agricultural Improvement and Power District (Salt River Project), a utility based in Phoenix, Arizona, entered into a 20-year PPA to secure 100 per cent of the output from TransCanada's planned Coolidge generating station. The simple-cycle natural gas-fired peaking power facility to be located in Coolidge, Arizona is expected to be commissioned in 2011 and have a nominal generating capacity of 575 MW.

Western Power relies on its two integrated functions, marketing and plant operations, to generate earnings. The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced from the PPAs, markets uncommitted volumes from the cogeneration facilities, and purchases and resells power and natural gas to maximize the value of the cogeneration facilities. The marketing function is integral to optimizing Energy's return from its portfolio of power supply and to managing risks associated with uncontracted volumes. A portion of Energy's power is sold into the spot market for operational reasons and the amount of supply volumes eventually sold into the spot market is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where TransCanada would otherwise have to purchase electricity in the open market to fulfil its contractual sales obligations. To reduce exposure to spot market prices on uncontracted volumes, Western Power had, as at December 31, 2008, fixed-price power sales contracts to sell approximately 8,800 gigawatt hours (GWh) in 2009 and 5,500 GWh in 2010.

Plant operations in Alberta consist of five natural gas-fired cogeneration power plants with an approximate combined output capacity of 400 MW ranging from 27 MW to 165 MW per facility. A portion of the expected output is sold under long-term contracts and the remaining output is subject to fluctuations in the price of power and natural gas. Market heat rate is an economic measure for natural gas-fired power plants and is determined by dividing the average price of power per megawatt hour (MWh) by the average price of natural gas per GJ for a given period. To the extent power is not sold under long-term contracts and plant fuel gas has not been purchased under long-term contracts, the profitability of a natural gas-fired generating facility rises in proportion to an increase in the market heat rate and declines in proportion to a decrease in the market heat rate. Market heat rates in Alberta increased in 2008 by approximately six per cent as a result of an increase in average power prices, partially offset by an increase in spot market natural gas prices. Market heat rates averaged approximately 12.05 GJ/MWh in 2008 compared to approximately 11.40 GJ/MWh in 2007.

Western Power's plants operated with an average plant availability of approximately 87 per cent in 2008 compared to 90 per cent in 2007. The decrease was primarily due to an extended outage at the Cancarb power plant.

Western Power Results
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Revenues			
Power	**1,140**	1,045	1,185
Other[(1)]	**130**	89	169
	1,270	1,134	1,354
Commodity purchases resold			
Power	**(575)**	(608)	(767)
Other[(2)]	**(64)**	(65)	(135)
	(639)	(673)	(902)
Plant operating costs and other	**(180)**	(135)	(135)
Depreciation	**(25)**	(18)	(20)
Operating income	**426**	308	297

(1) Other revenue includes sales of natural gas, sulphur and thermal carbon black.
(2) Other commodity purchases resold includes the cost of natural gas sold.

Western Power Sales Volumes
Year ended December 31 *(GWh)*

	2008	2007	2006
Supply			
Generation	**2,322**	2,154	2,259
Purchased			
Sundance A & B and Sheerness PPAs	**12,368**	12,199	12,712
Other purchases	**807**	1,433	1,905
	15,497	15,786	16,876
Contracted vs. Spot			
Contracted	**11,284**	11,998	12,750
Spot	**4,213**	3,788	4,126
	15,497	15,786	16,876

Operating income was $426 million in 2008, an increase of $118 million from $308 million in 2007. The increase was primarily due to increased margins from a combination of higher overall realized power prices and market heat rates on uncontracted volumes of power sold, as well as a $23 million increase from sales of sulphur at significantly higher prices in 2008. In 2008, the Company sold the remainder of its sulphur stock pile, which it has been selling in modest quantities on a break-even basis since 2005.

Revenues increased in 2008 primarily due to the higher overall power sales prices. Commodity purchases resold decreased in 2008 compared to 2007 primarily due to a decrease in volumes purchased and the expiry of certain retail contracts. Plant operating costs and other, which includes fuel gas consumed in generation, increased in 2008 as a result of higher volumes of gas purchased at higher prices. Purchased power volumes in 2008 decreased primarily due to the expiry of certain retail contracts, partially offset by increased utilization from the Alberta PPAs. Approximately 27 per cent of power sales volumes were sold in the spot market in 2008 compared to 24 per cent in 2007.

Operating income was $308 million in 2007, an increase of $11 million from $297 million in 2006. The increase was primarily due to lower PPA costs, partially offset by slightly lower overall realized power prices. Revenues decreased in 2007 compared to 2006 due mainly to the lower overall power sales prices realized in 2007 as well as lower volumes purchased and generated. Commodity purchases resold decreased in 2007 compared to 2006 primarily due to lower PPA costs, a decrease in volumes purchased and the expiry of certain retail contracts. Purchased power volumes in 2007 decreased compared to 2006 mainly as a result of an increase in outage hours at the Sundance A facility and the expiry of certain retail contracts. Approximately 24 per cent of power sales volumes were sold into the spot market in 2007, which was consistent with 2006.

Eastern Power

Eastern Power owns approximately 5,800 MW of power generation capacity, including facilities under construction or in the development phase. Eastern Power's current operating power generation assets are Ravenswood, TC Hydro, OSP, Bécancour, the Cartier Wind farms and Grandview. Ravenswood, acquired in August 2008, is a 2,480 MW gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology. Ravenswood, located in Queens, has the capacity to serve approximately 21 per cent of the overall peak load in New York City. The TC Hydro assets include 13 hydroelectric stations housing a total of 39 hydroelectric generating units in New Hampshire, Vermont and Massachusetts.

OSP, a natural gas-fired combined-cycle facility, is the largest power plant in Rhode Island. Bécancour, a natural gas-fired cogeneration plant located near Trois Rivières, Québec, was placed into service in September 2006. The entire power output is supplied to Hydro-Québec under a 20 year power purchase contract. Steam from this facility is sold to an industrial customer for use in commercial processes. Cartier has a combined generating capacity of 320 MW and consists of three wind farms, Carleton, Anse-á-Valleau, and Baie-des-Sables, which were placed into service in November 2008, November 2007 and November 2006, respectively. Output from these three wind farms is supplied to Hydro-Québec under 20 year power purchase contracts. Grandview is a natural gas-fired cogeneration facility on the site of the Irving Oil Refinery (Irving) in Saint John, New Brunswick. Under a 20 year tolling arrangement which will expire in 2025, Irving supplies fuel for the plant and contracts for 100 per cent of the plant's heat and electricity output.

Eastern Power conducts its business primarily in the deregulated New England and New York power markets and in Eastern Canada. In the New England market, TransCanada has established a marketing operation through its wholly owned subsidiary, TransCanada Power Marketing Ltd. (TCPM). TCPM is located in Westborough, Massachusetts, and effective January 1, 2009, also markets the output from the Ravenswood facility. To reduce exposure to spot market prices on uncontracted volumes, Eastern Power had, as at December 31, 2008, fixed price sales contracts to sell forward approximately 13,000 GWh in 2009 and 15,000 GWh in 2010, although certain contracted volumes are dependant on customer usage levels. Actual amounts contracted in future periods will depend on market liquidity and other factors. Fixed price sales contracts in 2009 exclude approximately 4,300 GWh of generation from the Bécancour power plant as a result of a suspension of electricity generation that began in January 2008 and continues through December 2009. The suspension of the Bécancour power facility is discussed further in the "Energy – Opportunities and Developments" section of this MD&A.

TCPM focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers while managing a portfolio of power supplies sourced from both its own generation and wholesale power purchases. In 2008, TCPM continued to expand its marketing presence and customer base in the New England market.

The Forward Capacity Market (FCM) in the New England power pool is intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. Under the FCM, Independent System Operator New England (ISO-NE) projects the needs of the power system three years in advance, following which it holds an annual auction to purchase power resources to satisfy future needs. Prior to the auction period, certain transition payments are made to capacity suppliers in New England that were in existence at June 2006.

ISO-NE has undertaken two Forward Capacity Auctions (FCA) under the FCM framework for procurement of installed capacity; FCA1 for the 2010-2011 period and FCA2 for the 2011-2012 period. All of Eastern Power's existing and planned power assets in the New England market were entered into both FCA1 and FCA2. Both auctions resulted in significant amounts of qualifying capacity resulting in decreased prices. The clearing prices in these auctions were US$4.25 and US$3.12 per kilowatt-month, respectively. Future auction results will be affected by actual demand growth and the pace of progress in the development of new qualifying resources that bid into these auctions, as well as other factors.

The New York Independent System Operator (NYISO) relies on a locational capacity market intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. Currently, a series of voluntary forward auctions and a mandatory spot demand curve price setting process is used to determine the price that is paid to capacity suppliers. There are separate demand curves for each of the three capacity zones: Long Island, New York City and the rest of the state. Ravenswood's capacity is located in the New York City capacity zone. Energy and capacity prices for Ravenswood are affected by circumstances that have an impact on supply and demand within this zone, certain NYISO market rules impacting both buyers and suppliers of capacity in this zone, and certain reliability criteria set out by the NYISO and the New York State Reliability Council. There is currently surplus capacity within this zone, however, TransCanada expects capacity will tighten after 2009 as a result of the expected retirement of a power station owned by the New York Power Authority.

Eastern Power Results[1]
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Revenues			
Power	**1,254**	1,481	789
Other[2]	**350**	239	292
	1,604	1,720	1,081
Commodity purchases resold			
Power	**(519)**	(755)	(379)
Other[3]	**(324)**	(208)	(257)
	(843)	(963)	(636)
Plant operating costs and other	**(342)**	(454)	(226)
Depreciation	**(81)**	(48)	(32)
Operating income	**338**	255	187

(1) Includes Carleton, Ravenswood, Anse-à-Valleau, Baie-des-Sables and Bécancour effective November 2008, August 2008, November 2007, November 2006 and September 2006, respectively.

(2) Other revenue includes sales of natural gas.

(3) Other commodity purchases resold includes the cost of natural gas sold.

Eastern Power Sales Volumes[1]
Year ended December 31 *(GWh)*

	2008	2007	2006
Supply			
Generation	**5,043**	8,095	4,700
Purchased	**6,183**	6,986	3,091
	11,226	15,081	7,791
Contracted vs. Spot			
Contracted	**10,990**	14,505	7,374
Spot	**236**	576	417
	11,226	15,081	7,791

(1) Includes Carleton, Ravenswood, Anse-à-Valleau and Baie-des-Sables effective November 2008, August 2008, November 2007 and November 2006, respectively. Bécancour is included in Eastern Power effective September 2006 through December 2007.

Operating income was $338 million in 2008, $83 million higher than the $255 million earned in 2007. The increase was primarily due to increased water flows from the TC Hydro generation assets and higher realized prices on sales to commercial and industrial customers in New England, incremental income from the first full year of operations from the Anse-à-Valleau wind farm and the start-up of the Carleton wind farm in November 2008. On December 31, 2008, Ravenswood fulfilled its obligation under a tolling agreement with Hess Corporation that was in place at the time of acquisition. In 2009, TCPM will manage the marketing output of the Ravenswood plant in a manner consistent with its other U.S. northeast portfolio of assets. The agreement to temporarily suspend generation at the Bécancour facility beginning January 2008 resulted in decreases to power revenues, plant operating costs and other, generation volumes and contracted sales in 2008. The temporary suspension agreement has not materially affected Eastern Power's operating income due to capacity payments received pursuant to the agreement with Hydro-Québec. The agreement to suspend generation at the Bécancour facility was extended for one year to December 31, 2009.

Eastern Power's power revenues were $1,254 million in 2008, a decrease of $227 million from $1,481 million in 2007. This was primarily due to the temporary suspension of generation at the Bécancour facility and decreased sales to commercial and industrial customers in the New England market, partially offset by higher realized prices in New England, increased water flows through the TC Hydro generation assets, and incremental revenue from Ravenswood. Other revenue and other commodity purchases resold increased year-over-year as a result of an increase in the quantity of natural gas purchased and resold under OSP's and TCPM's natural gas supply contracts. Power commodity purchases resold and purchased power volumes were lower in 2008 due to the impact of decreased sales volumes to commercial and industrial customers, lower overall cost per GWh on purchased power volumes and increased power generation from the TC Hydro assets, which reduced the requirement to purchase power to fulfill contractual sales obligations. Plant operating costs and other, which includes fuel gas consumed in generation, were lower in 2008 primarily due to the temporary suspension of generation at the Bécancour facility, partially offset by incremental operating costs from Ravenswood.

Operating income was $255 million in 2007, $68 million higher than the $187 million earned in 2006. The increase was primarily due to incremental income from the first full year of operations from the Bécancour facility and the Baie-des-Sables wind farm, as well as the start-up of the Anse-à-Valleau wind farm in November 2007. Also contributing to the increase were payments received under the start-up of the FCM in New England and higher sales volumes to commercial and industrial customers in 2007. Partially offsetting these increases was the impact of reduced water flows from the TC Hydro generation assets in 2007, compared to the above-average water flows experienced in 2006 following higher precipitation in the surrounding area.

Bruce Power

As at December 31, 2008, TransCanada and BPC Generation Infrastructure Trust (BPC), a trust established by the Ontario Municipal Employees Retirement System, each owned a 48.9 per cent interest in Bruce A (2007 – 48.7 per cent). The remaining 2.2 per cent interest in Bruce A is owned by the Power Workers' Union Trust, the Society of Energy Professionals Trust and Bruce Power Employee Investment Trust. The Bruce A partnership subleases Bruce A Units 1 to 4 from the Bruce B partnership. TransCanada continues to own 31.6 per cent of Bruce B, which consists of Units 5 to 8 and the supporting site infrastructure.

The following Bruce Power financial results reflect the operations of six of the eight Bruce Power units:

Bruce Power Results

Year ended December 31 *(millions of dollars)*	**2008**	2007	2006
Bruce Power (100 per cent basis)			
Revenues			
Power	**2,064**	1,920	1,861
Other[1]	**96**	113	71
	2,160	2,033	1,932
Operating expenses			
Operations and maintenance[2]	**(1,066)**	(1,051)	(912)
Fuel	**(139)**	(104)	(96)
Supplemental rent[2]	**(174)**	(170)	(170)
Depreciation and amortization	**(151)**	(151)	(134)
	(1,530)	(1,476)	(1,312)
	630	557	620
TransCanada's proportionate share:			
Bruce A (48.9%)	**62**	24	91
Bruce B (31.6%)	**158**	161	137
	220	185	228
Adjustments	**(19)**	(18)	7
TransCanada's operating income from Bruce Power	**201**	167	235
Bruce Power – Other Information			
Plant availability			
Bruce A	**82%**	78%	81%
Bruce B	**87%**	89%	91%
Combined Bruce Power	**86%**	86%	88%
Planned outage days			
Bruce A	**91**	121	81
Bruce B	**100**	93	65
Unplanned outage days			
Bruce A	**27**	17	37
Bruce B	**65**	32	31
Sales volumes (GWh)			
Bruce A – 100 per cent	**10,580**	10,180	10,650
Bruce A – TransCanada's proportionate share	**5,159**	4,959	5,158
Bruce B – 100 per cent	**24,680**	25,290	25,820
Bruce B – TransCanada's proportionate share	**7,799**	7,992	8,159
Combined Bruce Power – 100 per cent	**35,260**	35,470	36,470
TransCanada's proportionate share	**12,958**	12,951	13,317
Results per MWh			
Bruce A power revenues	**$62**	$59	$58
Bruce B power revenues	**$57**	$52	$48
Combined Bruce Power revenues	**$59**	$55	$51
Combined Bruce Power fuel	**$4**	$3	$3
Combined Bruce Power total operating expenses[3]	**$42**	$41	$35
Percentage of output sold to spot market	**23%**	45%	35%

(1) Other revenue includes Bruce A fuel cost recoveries of $61 million in 2008 (2007 – $35 million; 2006 – $30 million). Other revenue also includes unrealized losses of $6 million as a result of changes in fair value of held-for-trading derivatives in 2008 (2007 – $47 million gain; 2006 – nil).

(2) Includes adjustments to eliminate the effects of inter-partnership transactions between Bruce A and Bruce B.

(3) Net of fuel cost recoveries.

TransCanada's operating income from Bruce Power was $201 million in 2008 compared to $167 million in 2007. TransCanada's proportionate share of operating income in Bruce A increased $38 million to $62 million in 2008 compared to 2007 primarily due to higher realized prices and higher volumes associated with a decrease in outage days in 2008. TransCanada's proportionate share of operating income in Bruce B decreased $3 million to $158 million in 2008 compared to 2007 primarily due to higher operating costs and lower volumes associated with an increase in outage days in 2008, and unrealized gains in 2007 from changes in the fair value of power swaps and forwards. Partially offsetting these decreases were higher realized prices reflecting a higher proportion of volumes sold at higher contract prices.

Combined Bruce Power prices, which are based solely on power revenues, were $59 per MWh in 2008 compared to $55 per MWh in 2007, reflecting higher prices on both contracted volumes and uncontracted volumes sold into the spot market. Bruce Power's combined operating expenses (net of fuel cost recoveries) increased to $42 per MWh in 2008 from $41 per MWh in 2007 primarily due to higher operating costs in 2008.

The Bruce units ran at a combined average availability of 86 per cent in 2008, which was consistent with the average availability in 2007.

TransCanada's operating income from its combined investment in Bruce Power was $167 million in 2007 compared to $235 million in 2006. The decrease of $68 million was primarily due to lower output and higher operating costs associated with an increase in planned outage days, partially offset by higher overall realized prices.

Adjustments to TransCanada's interest in Bruce Power's income before income taxes were lower in 2008 and 2007 than in 2006 primarily due to lower positive purchase price amortizations related to the expiry of power sales agreements.

The overall plant availability percentage in 2009 is expected to be in the low 90s for the four Bruce B units and the mid-80s for the two operating Bruce A units. An approximate six week maintenance outage of Bruce B Unit 8 is scheduled to begin in mid-April 2009 and an approximate six week maintenance outage of Bruce B Unit 6 is scheduled to begin in early October 2009. An approximate six week maintenance outage of Bruce A Unit 4 is scheduled to start in early March 2009 and an approximate one-month outage of Bruce A Unit 3 is expected to commence in mid-March 2009.

Bruce A

Income from Bruce A is affected by overall plant availability, which in turn is affected by planned and unplanned maintenance. As a result of a contract with the Ontario Power Authority (OPA), all of the output from Bruce A is effectively sold at a fixed price per MWh, adjusted for inflation annually on April 1. In addition, fuel costs are recovered from the OPA. In accordance with a 2007 contract amendment, effective April 1, 2008, the fixed price for output from Bruce A was $63.00 per MWh, an increase of $2.11 per MWh, subject to inflation adjustments from October 31, 2005.

Bruce A Fixed Price

	per MWh
April 1, 2008 – March 31, 2009	$63.00
April 1, 2007 – March 31, 2008	$59.69
April 1, 2006 – March 31, 2007	$58.63

Support payments received pursuant to the OPA contract are equal to the difference between the fixed prices under the OPA contract and spot market prices and are capped at $575 million for the period ending on the commercial in-service date of the later of the restarted Unit 1 and Unit 2. As at December 31, 2008, Bruce A had received $368 million towards this cap. Post-refurbishment prices will also be adjusted for capital cost variances associated with the refurbishment and restart projects.

Bruce B
Income from Bruce B is directly affected by fluctuations in wholesale spot market prices for electricity and overall plant availability, which in turn is affected by planned and unplanned maintenance.

As part of Bruce Power's contract with the OPA, sales from the Bruce B Units 5 to 8 are subject to a floor price adjusted annually for inflation on April 1.

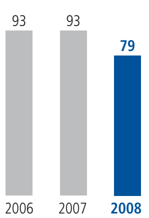
Bruce B Floor Price

	per MWh
April 1, 2008 – March 31, 2009	$47.66
April 1, 2007 – March 31, 2008	$46.82
April 1, 2006 – March 31, 2007	$45.99

Payments received pursuant to the Bruce B floor price mechanism may be subject to a recapture payment dependent on annual spot prices over the term of the contract. Bruce B net earnings to date have not included any amounts received pursuant to this floor mechanism. To further reduce its exposure to spot market prices, as at December 31, 2008, Bruce B had entered into fixed price sales contracts to sell forward approximately 12,460 GWh for 2009 and 7,100 GWh for 2010.

Plant Availability

Power Plant Availability (excluding Bruce Power)
(per cent)



Weighted average power plant availability for all plants, excluding Bruce Power, was 79 per cent in 2008 compared to 93 per cent in 2007 and 2006. Plant availability represents the percentage of time in a year that the plant is available to generate power whether actually running or not. Western Power's plant availability was affected negatively throughout 2008 and in late 2007 by an outage at the Cancarb power plant. Eastern Power achieved plant availability of 78 per cent in 2008, 18 per cent lower than 2007 as a result of outages experienced on Units 10 and 30 at Ravenswood throughout fourth quarter 2008 and a longer than expected outage at OSP in late 2008. Additionally, Bécancour, which had an availability of 97 per cent in 2007, is not included in Eastern Power's 2008 availability measurement as a result of a temporary suspension of power generation from the plant throughout 2008.

Weighted Average Plant Availability
Year ended December 31

	2008	2007	2006
Western Power	**87%**	90%	88%
Eastern Power	**78%**	96%	95%
Bruce Power	**86%**	86%	88%
All plants, excluding Bruce Power	**79%**	93%	93%
All plants	**83%**	91%	91%

Natural Gas Storage
TransCanada owns or has rights to 120 Bcf of natural gas storage capacity in Alberta, including a 60 per cent ownership interest in CrossAlta, an independently operated storage facility. TransCanada also has contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015.

Natural Gas Storage Capacity

	Working Gas Storage Capacity (Bcf)	Maximum Injection/ Withdrawal Capacity (mmcf/d)
Edson	50	725
CrossAlta[1]	32	288
Third-party storage	38	630
	120	1,643

(1) Represents TransCanada's 60 per cent ownership interest in CrossAlta, a 54 Bcf, 480 mmcf/d facility.

TransCanada believes the market fundamentals for natural gas storage remain unchanged. The Company's gas storage capability helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to Alberta and the rest of North America. The increasing seasonal imbalance in North American natural gas supply and demand has increased natural gas price volatility and the demand for storage services. Alberta-based storage will continue to serve market needs and could play an important role should additional gas supplies be connected to North American markets. Energy's natural gas storage business operates independently from TransCanada's regulated natural gas transmission business and from ANR's regulated storage business, which is included in TransCanada's Pipelines segment.

TransCanada manages the exposure of its non-regulated natural gas storage assets to seasonal natural gas price spreads by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales.

TransCanada offers a broad range of injection and withdrawal storage alternatives tailored to customer needs in short-term to multi-year contracts. Market volatility frequently creates arbitrage opportunities and TransCanada's storage operations offer solutions to capture value from these short-term price movements. Earnings from third-party storage capacity contracts are recognized over the term of the contract. At December 31, 2008, TransCanada had contracted approximately 70 per cent of the total 120 Bcf of working gas storage capacity in 2009 and 57 per cent of storage capacity in 2010.

Proprietary natural gas storage transactions are comprised of a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, TransCanada locks in future positive margins, thereby effectively eliminating its exposure to natural gas seasonal price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair values based on the forward market prices for the contracted month of delivery. Changes in the fair value of these contracts are recorded in Revenues. Effective April 2007, TransCanada adopted an accounting policy to record proprietary natural gas inventory held in storage at its fair value using the one-month forward price for natural gas. Changes in the fair value of inventory are recorded in Revenues. Changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sales contracts are excluded in determining comparable earnings as they are not representative of amounts that will be realized on settlement.

Natural Gas Storage operating income was $135 million in 2008, a decrease of $11 million compared to 2007. The decrease was primarily due to lower average storage values realized by CrossAlta, partially offset by higher earnings from the sale of proprietary natural gas at Edson in 2008. There were no net unrealized gains or losses in 2008 from changes in the fair value of proprietary natural gas forward purchase and sales contracts compared to net unrealized gains of $10 million in 2007.

Natural Gas Storage operating income was $146 million in 2007, an increase of $53 million compared to 2006. The increase was primarily due to income earned from the first full year of operations from the Edson facility.

ENERGY – OPPORTUNITIES AND DEVELOPMENTS

Ravenswood In August 2008, TransCanada acquired the multiple-unit Ravenswood generating facility located in Queens, New York, which employs dual-fuel capable steam turbine, combined-cycle and combustion turbine technology. During 2008, Ravenswood operated under a tolling arrangement that existed at the date of acquisition and expired on December 31, 2008. Under the tolling arrangement, all energy generated from the facility was provided to Hess Corporation for a fixed operating fee. In January 2009, Ravenswood commenced earning revenues from the sale of energy generated from the facility into the New York market. TransCanada's marketing operation located in Westborough, Massachusetts manages the marketing of output from Ravenswood.

The integration into TransCanada's operations of the Ravenswood generating station, acquired in August 2008, is now complete. Shortly after closing the acquisition, TransCanada experienced a forced outage event affecting one of the larger multiple generating units. The unit is currently undergoing repair and it is expected that the event will be insured both for physical damage and business interruption. Other refurbishment work is being undertaken at the station while the repair work is being completed and as a result, unit availability is expected to improve in the future.

Bruce Power Under a long-term agreement reached in 2005 between Bruce Power and the OPA, Bruce A has committed to refurbish and restart the currently idle Units 1 and 2, extend the operating life of Unit 3 with a full refurbishment and replace the steam generators on Unit 4. Bruce Power and the OPA amended the Bruce A refurbishment agreement in 2007 to allow for a full refurbishment of Unit 4, which will extend the expected operating life of the unit. Under the 2007 amendment, the OPA had the option to elect, prior to April 1, 2008, to proceed with a three-unit refurbishment and restart program instead of the revised four-unit program. The OPA chose to not exercise this option and instead elected to proceed with the four-unit refurbishment and restart program.

In fourth quarter 2008, Bruce Power completed a review of the operating life estimates for Units 3 and 4. Unit 3 is now expected to remain in commercial service until 2011, which provides the benefit of nearly two additional years of power generation before the unit commences an expected 36 month refurbishment. After the refurbishment, the operating life of Unit 3 is expected to be extended to 2038 from 2037. In addition, Unit 4 is now expected to remain in commercial service until 2016, providing nearly seven years of generation before the unit commences a similar refurbishment period, after which, the estimated operating life of Unit 4 is expected to be extended to 2042 from 2036.

The capital cost for the refurbishment and restart of Bruce A Units 1 and 2 is expected to be approximately $3.4 billion, based on a comprehensive review in January 2008 of the estimated costs to complete the project, which is an increase from the original cost estimate of $2.75 billion. TransCanada's share is expected to be approximately $1.7 billion, compared to an original estimate of $1.4 billion. The project cost increases are subject to the capital cost risk- and reward-sharing mechanism under TransCanada's agreement with the OPA. Bruce A Units 1 and 2 are expected to produce an additional 1,500 MW of power when completed in 2010.

As at December 31, 2008, Bruce A had incurred $2.6 billion in costs with respect to the refurbishment and restart of Units 1 and 2 and approximately $200 million for the refurbishment of Units 3 and 4.

Portlands Energy Construction continued in 2008 on Portlands Energy. The facility was operational in single-cycle mode in the summer of 2008 and is expected to be fully commissioned in its combined-cycle mode in first quarter 2009. Portlands Energy will provide power under a 20-year Accelerated Clean Energy Supply contract with the OPA. The expected capital cost is $730 million, of which TransCanada's portion is 50 per cent.

Coolidge In May 2008, the Phoenix, Arizona-based utility, Salt River Project, signed a 20-year power purchase contract to secure 100 per cent of the output from the simple-cycle natural gas-fired peaking power facility currently under development. In December 2008, the Arizona Corporation Commission granted a Certificate of Environmental Compatibility approving construction of the facility. Construction is expected to begin in the summer of 2009 and the facility is expected to be commissioned in 2011.

Halton Hills Construction of Halton Hills continued in 2008. The project includes the construction and operation of a natural gas-fired power plant near the town of Halton Hills, Ontario. TransCanada expects to invest approximately $670 million in the project, which is anticipated to be in service in third quarter 2010. Power from the facility will be sold to the OPA under a 20-year Clean Energy Supply contract.

Cartier Wind The Carleton wind farm commenced commercial operation in November 2008, providing up to 109 MW of power to the Hydro-Québec grid. Carleton is the third phase of the six-phase, multi-year Cartier Wind project, located in the Gaspé region of Québec. The first two phases, Baie-des-Sables and Anse-á-Valleau, went into service in November of 2006 and 2007, respectively, generating up to 110 MW and 101 MW of power, respectively. The remaining phases of Cartier Wind are expected to be constructed through 2012, subject to the necessary approvals. Capacity is expected to total 740 MW when all six phases are complete. TransCanada has a 62 per cent ownership interest in these wind farms.

Kibby Wind In July 2008, the State of Maine's Land Use Regulation Commission approved the final development plan submitted by TransCanada to build, own and operate a wind farm, located in the Kibby and Skinner townships in Maine. Construction of the facilities at a cost of approximately US$320 million began in July 2008 and commissioning of the first phase is expected to begin in fourth quarter 2009.

Bécancour TransCanada entered into an agreement with Hydro-Québec in November 2007 to temporarily suspend all electricity generation from the Bécancour power plant during 2008. In 2008, the agreement was extended through to December 2009. In 2009, TransCanada will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

Power Transmission Line Projects TransCanada is pursuing proposals to build, own and operate power transmission lines, including the Zephyr and Chinook transmission line projects. The projects are each proposed 500 kilovolt (kV) high voltage direct current (HVDC) transmission lines originating in Wyoming and Montana, respectively, and terminating in Nevada. If constructed, each project would cost approximately US$3 billion and be capable of delivering 3,000 MW of power. In December 2008, TransCanada filed applications for both projects requesting approval from the FERC to charge negotiated rates and to proceed with an open season in the spring of 2009, with 50 per cent of the capacity of each line already pre-subscribed for a period of 25 years. In February 2009, the FERC approved both applications. Pending successful completion of the open seasons, regulatory work could commence later in 2009, followed by construction commencing in 2012 and a potential in-service date of late 2014.

TransCanada is pursuing a proposal to build NorthernLights, a 500 kV HVDC electric transmission line running from central Alberta to a terminal in southern Alberta and interconnecting with the Pacific Northwest. NorthernLights is expected to cost approximately $2 billion and provide up to 3,000 MW of power.

Broadwater LNG In March 2008, the FERC authorized the construction and operation of Broadwater, subject to conditions. In April 2008, the New York Department of State determined that construction and operation of the project would not be consistent with the State's coastal zone policies. As a result of this unfavourable decision, TransCanada wrote down $27 million after tax ($41 million pre-tax) of costs for Broadwater that had been capitalized to March 31, 2008. TransCanada has appealed the determination of the New York Department of State to the U.S. Department of Commerce and a decision is expected in early 2009.

ENERGY – BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices

TransCanada operates in competitive power and natural gas markets in North America. Volatility in power and natural gas prices is caused by market forces such as fluctuating supply and demand, which are greatly affected by weather events. Energy's earnings from the sale of uncontracted volumes are subject to price volatility. Although Energy commits a significant portion of its supply to medium- to long-term sales contracts, it retains an amount of unsold supply in order to provide flexibility in managing the Company's portfolio of wholly owned assets.

Uncontracted Volumes

Energy has uncontracted power sales volumes in Western Power and Eastern Power and through its investment in Bruce Power. In addition, with the acquisition of Ravenswood, at December 31, 2008, Eastern Power significantly increased its level of uncontracted sales volumes, which are subject to price volatility. Sale of uncontracted power volumes into the spot market is subject to market price volatility, which directly impacts earnings. Bruce B has a significant amount of uncontracted volumes subject to a floor price mechanism that are sold into the wholesale power spot market under contract price terms with the OPA, while 100 per cent of the Bruce A output is sold into the Ontario wholesale power spot market under fixed contract price terms with the OPA. The natural gas storage business is subject to fluctuating natural gas seasonal spreads generally determined by the differential in natural gas prices in the traditional summer injection and winter withdrawal seasons. As a result, the Company hedges capacity with a portfolio of contractual commitments containing varying terms.

Liquidity Risk

A decrease in the number and credit quality of counterparties with which to transact may increase the Company's exposure to spot prices by reducing its ability to lock in forward sale prices at acceptable contract terms.

Plant Availability

Maintaining plant availability is essential to the continued success of the Energy business. Plant operating risk is mitigated through a commitment to TransCanada's operational excellence strategy, which is to provide low-cost, reliable operating performance at each of the Company's facilities. Unexpected plant outages and the duration of outages could result in lower plant output and sales revenue, reduced margins and increased maintenance costs. At certain times, unplanned outages may require power or natural gas purchases at market prices to ensure TransCanada meets its contractual obligations.

Weather

Extreme temperature and weather events in North America and the Gulf of Mexico often create price volatility and demand for power and natural gas. These same events may also restrict the availability of power and natural gas. Seasonal changes in temperature can also affect the efficiency and output capability of natural gas-fired power plants. Variability in wind speeds may impact the earnings of the Cartier Wind assets.

Hydrology

TransCanada's power operations are subject to hydrology risk arising from the ownership of hydroelectric power generation facilities in the northeastern U.S. Weather changes, weather events, local river management and potential dam failures at these plants or upstream facilities pose potential risks to the Company.

Execution and Capital Cost

Energy's new construction programs in Ontario, Québec, Maine and Arizona, including its investment in Bruce Power, are subject to execution and capital cost risks. At Bruce Power, Bruce A's four unit refurbishment and restart project is also subject to a capital cost risk- and reward-sharing mechanism with the OPA.

Asset Commissioning

Although all of TransCanada's newly constructed assets go through rigorous acceptance testing prior to being placed in service, there is a risk that these assets may have lower than expected availability or performance, especially in their first year of operations.

Regulation of Power Markets

TransCanada operates in both regulated and deregulated power markets. As electricity markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, price caps, emission controls, unfair cost allocations to generators and attempts by others to take out-of-market actions to build excess generation that negatively affects the price for capacity or energy, or both. In addition, TransCanada's development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedule and cost. TransCanada continues to monitor regulatory issues and regulatory reform and participate in and lead discussions around these topics.

Refer to the "Risk Management and Financial Instruments" section of this MD&A for information on additional risks and managing risks in the Energy business.

ENERGY – OUTLOOK

TransCanada assumes that its operations in 2009 will be materially consistent with those in 2008 and includes the positive impact of a full year of earnings from Ravenswood, incremental earnings from Portlands Energy, which is expected to be commissioned in first quarter 2009, and a decrease in planned outages at Bruce Power. These positive impacts are expected to be partially offset by a return to more normal hydrology levels at TC Hydro from the record levels experienced in 2008. In addition, the current economic climate is negatively affecting demand, liquidity and prices in commodity markets in which TransCanada operates.

Although TransCanada has sold forward significant output from its power plants and Alberta PPAs, as well as capacity from its natural gas storage facilities, operating income in 2009 can be affected by changes in the spot market price of power, market heat rates, hydrology, forward capacity payments, natural gas storage spreads and unplanned outages. Operating income from Energy's U.S. operations is affected by changes in the U.S./Canadian dollar exchange rates.

Other factors such as plant availability, regulatory changes, weather, currency movements, and overall stability of the energy industry can also affect 2009 operating income. Refer to the "Energy – Business Risks" section of this MD&A for a complete discussion of these factors.

Following the expiry of the Ravenswood tolling arrangement with Hess Corporation on December 31, 2008, TransCanada will manage the ongoing marketing of the Ravenswood plant output in the same manner as it does with other generation assets in the U.S. Northeast. Dependent on market liquidity and other factors, a significant portion of the electricity generated by the Ravenswood facility in 2009 and beyond may be sold at spot prices. As noted in the "Energy – Business Risk" section of this MD&A, spot prices for electricity are subject to change depending on underlying energy commodity prices, available supply, demand and other factors.

Capital Expenditures

Energy's total capital expenditures in 2008 were $4.3 billion, including the acquisition of Ravenswood for $3.1 billion. Energy's overall capital spending in 2009 is expected to be approximately $1.4 billion, including cash calls for the Bruce A refurbishment and restart project and continued construction at Coolidge, Cartier Wind, Kibby Wind and Halton Hills.

CORPORATE

CORPORATE RESULTS
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Indirect financial charges and non-controlling interests	**291**	248	136
Interest income and other	**(9)**	(83)	(31)
Income taxes	**(180)**	(120)	(72)
Comparable Expenses[1]	**102**	45	33
Income tax reassessments and adjustments	**(26)**	(68)	(72)
Net Expenses/(Earnings), after income taxes	**76**	(23)	(39)

(1) Refer to the" Non-GAAP Measures" section of this MD&A for further discussion of comparable earnings.

Corporate reflects net expenses not allocated to specific business segments, including:

- *Indirect Financial Charges and Non-Controlling Interests* Direct financial charges are reported in their respective business segments and are associated primarily with debt and preferred securities related to the Company's wholly owned natural gas pipelines. Indirect financial charges, including the related foreign exchange impacts, reside mainly in Corporate. These costs are influenced directly by the amount of debt the Company maintains, the degree to which the Company is affected by fluctuations in interest and foreign exchange rates and the amount of interest capitalized for projects under construction.
- *Interest Income and Other* Interest Income and Other includes interest earned on invested cash balances and income tax refunds. Also included are foreign exchange gains and losses related to translation of foreign-denominated working capital and derivatives used to manage the Company's exposure to U.S. dollar net income.
- *Income Taxes* Income tax recoveries includes income taxes calculated on Corporate's net expenses as well as income tax refunds, reassessments and adjustments that have not been excluded for comparable earnings purposes.

CORPORATE – FINANCIAL RESULTS

Net expenses in Corporate were $76 million in 2008 compared to net earnings of $23 million and $39 million in 2007 and 2006, respectively.

Corporate's net expenses in 2008 included favourable income tax reassessments and adjustments of $26 million compared to $68 million in 2007. Excluding these income tax adjustments, Corporate's comparable expenses increased $57 million in 2008 compared to 2007. The increase in comparable expenses was primarily due to net unrealized losses of $39 million after tax from changes in the fair value of derivatives, which are used to manage the Company's exposure to rising interest rates but do not qualify as hedges for accounting purposes. The fair value of these derivatives was negatively impacted as interest rates dropped to historic lows late in fourth quarter 2008. In addition, higher financial charges resulting from financing the Company's 2008 capital program, including the Ravenswood acquisition, and higher losses from the change in fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations were partially offset by increased capitalization of interest to finance a larger capital spending program. The losses from the foreign exchange derivatives were partially offset by the positive impact of a stronger U.S. dollar reported in the Pipelines and Energy businesses.

Corporate's net earnings in 2007 and 2006 included favourable income tax reassessments and adjustments of $68 million and $72 million, respectively. Excluding these income tax adjustments, Corporate's comparable expenses increased $12 million in 2007 compared to 2006. Net unrealized gains from the change in fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations and the impact of positive tax rate differentials were more than offset by higher financial charges resulting primarily from financing the ANR acquisition and additional ownership interest in Great Lakes.

CORPORATE – OUTLOOK

Corporate's net expenses in 2008 included certain favourable income tax reassessments and other impacts, including the $39 million net unrealized losses on interest rate derivatives, that are not expected to recur in 2009. Financing costs associated with debt issued in 2008 and 2009, and together with additional debt expected to be issued in 2009 to partially finance the Company's capital programs are expected to increase financial charges in Corporate in 2009. However, the increased charges are expected to be primarily offset by capitalized interest for projects under construction. Corporate's results could also be affected by debt levels, interest rates, foreign exchange rates and income tax refunds and adjustments. The performance of the Canadian dollar relative to the U.S. dollar will influence Corporate's results, although this impact is primarily mitigated by offsetting U.S.-dollar exposures in certain of TransCanada's other businesses and by the Company's hedging activities.

DISCONTINUED OPERATIONS

The $28 million income from discontinued operations in 2006 reflected bankruptcy settlements with Mirant related to TransCanada's Gas Marketing business, which was sold in 2001.

LIQUIDITY AND CAPITAL RESOURCES

Global financial markets are in turmoil, however, TransCanada's financial position and ability to generate cash from its operations in the short and long term to provide liquidity and to maintain financial capacity and flexibility to provide for planned growth remains sound and consistent with recent years. TransCanada's liquidity position remains solid, underpinned by highly predictable cash flow from operations, significant cash balances on hand from recent securities issues, as well as committed revolving bank lines of US$1.0 billion, $2.0 billion and US$300 million, maturing in November 2010, December 2012 and February 2013, respectively. To date, no draws have been made on these facilities as TransCanada has continued to have largely uninterrupted access to the Canadian commercial paper market on competitive terms. An additional $50 million and US$320 million of capacity remains available on committed bank facilities at TransCanada-operated affiliates with maturity dates from 2010 through 2012. TransCanada further strengthened its liquidity and financial position through additional financing transactions in 2008 and early 2009, as discussed below. TransCanada's liquidity, market and other risks are discussed further in the "Risk Management and Financial Instruments" section of this MD&A.

SUMMARIZED CASH FLOW
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Funds generated from operations[1]	**3,021**	2,621	2,378
(Increase)/decrease in operating working capital	**(181)**	215	(303)
Net cash provided by operations	**2,840**	2,836	2,075

[1] Refer to the "Non-GAAP Measures" section of this MD&A for further discussion of funds generated from operations.

HIGHLIGHTS

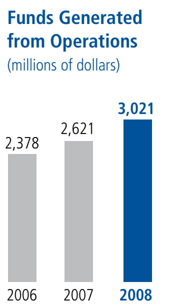
Investing Activities

- Capital expenditures and acquisitions, including assumed debt, totalled approximately $15.3 billion over the three-year period ending December 31, 2008.

Dividend

- TransCanada's Board of Directors declared a $0.38 per common share dividend for the quarter ending March 31, 2009, an increase of six per cent over the previous dividend amount.

Funds Generated from Operations

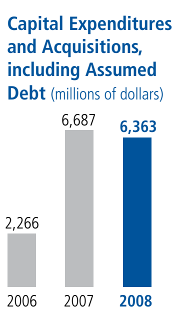


Funds Generated from Operations were $3.0 billion in 2008 compared to $2.6 billion and $2.4 billion, in 2007 and 2006, respectively. The increase in 2008 compared to 2007 was primarily due to proceeds from higher operating earnings and the Calpine bankruptcy settlements. The Energy business was the primary source of the increase in 2008 compared to 2007, partially offset by a reduced contribution from Corporate. The Pipelines business and growth in Energy's operations were the main drivers for the increase in 2007 compared to 2006.

Investing Activities

Capital expenditures totalled $3,134 million in 2008 compared to $1,651 million in 2007 and $1,572 million in 2006. Expenditures in 2008 and 2007 related primarily to the refurbishment and restart at Bruce Power, development of new pipelines, including Keystone, construction of new power facilities, expansion of existing pipelines and maintenance and capacity projects in the Pipelines business. Expenditures in 2006 were related primarily to construction of new power plants and natural gas storage facilities in Canada and maintenance and capacity projects in the Pipelines business.

TransCanada acquired Ravenswood from National Grid plc on August 26, 2008 for US$2.9 billion, subject to certain post-closing adjustments.



In accordance with TransCanada's agreement to increase its ownership interest in Keystone up to 79.99 per cent from 50 per cent, TransCanada has funded $362 million of Keystone cash calls since September 30, 2008. This has resulted in an acquisition of an incremental 12 per cent ownership interest for $176 million, bringing TransCanada's ownership interest to 62 per cent at December 31, 2008. The Keystone agreement is discussed further in the "Pipelines" section of this MD&A.

In 2007, TransCanada acquired ANR and an additional 3.6 per cent interest in Great Lakes from El Paso Corporation for US$3.4 billion, including US$491 million of assumed long-term debt. PipeLines LP acquired the remaining 46.4 per cent of Great Lakes from El Paso Corporation for US$942 million, including US$209 million of assumed long-term debt. In 2007, PipeLines LP purchased Sierra Pacific Resources' remaining one per cent ownership interest in Tuscarora for approximately $2 million. In a separate transaction in 2007, PipeLines LP also purchased TransCanada's one per cent ownership interest in Tuscarora for approximately $2 million. As a result of these transactions, PipeLines LP owns 100 per cent of Tuscarora.

In 2006, PipeLines LP acquired an additional 49 per cent interest in Tuscarora for US$100 million and also assumed US$37 million of debt. PipeLines LP also acquired an additional 20 per cent general partnership interest in Northern Border for US$307 million, in addition to indirectly assuming US$122 million of debt. TransCanada sold its 17.5 per cent general partner interest in Northern Border Partners, L.P. for proceeds of $35 million, net of current tax.

Financing Activities

In 2008, TransCanada issued Long-Term Debt of $2.2 billion and increased Notes Payable by $1.3 billion. Its proportionate share of Long-Term Debt issued by joint ventures was $173 million. Also in 2008, the Company reduced its Long-Term Debt by $840 million and its proportionate share of the Long-Term Debt of Joint Ventures by $120 million.

At December 31, 2008, total unsecured revolving and demand credit facilities of $4.2 billion were available to support the Company's commercial paper programs and for general corporate purposes. These credit facilities include the following:

- a $2.0 billion committed, syndicated revolving credit facility, maturing December 2012.
- a US$300 million committed, syndicated revolving facility, maturing February 2013. This facility is part of the US$1.0 billion TransCanada PipeLine USA Ltd. credit facility discussed below under the heading "2007 Long-Term Debt Financing Activities".
- a US$1.0 billion committed, extendible, expandable, unsecured bank facility, established in fourth quarter 2008, bearing interest at a floating rate plus a margin, with an initial term of 364 days and a one-year term renewal at the option of the borrower. The facility will support a new commercial paper program dedicated to funding a portion of expenditures for Keystone and for general partnership purposes.
- demand lines totaling $0.6 billion, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $433 million of these total lines of credit for letters of credit at December 31, 2008.

Short-Term Debt Financing Activities

In June 2008, TransCanada executed an agreement with a syndicate of banks for a US$1.5 billion committed, unsecured, one-year bridge loan facility, at a floating interest rate based on London Interbank Offered Rate (LIBOR) plus 30 basis points. The facility is extendible at the option of the Company for an additional six-month term at LIBOR plus 35 basis points. In August 2008, the Company used US$255 million from this facility to fund a portion of the Ravenswood acquisition and cancelled the remainder of the commitment. At December 31, 2008, the US$255 million remained outstanding on the facility.

In February 2007, the Company established a US$2.2 billion, committed, unsecured, one-year bridge loan facility and utilized $1.5 billion and US$700 million to partially finance its acquisition of ANR and its increased ownership of Great Lakes. At December 31, 2008, this facility had been fully repaid and cancelled.

2009 and 2008 Long-Term Debt Financing Activities

On February 17, 2009, the Company completed the issuance of Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. The proceeds are expected to be used to fund the Alberta System and Canadian Mainline rate bases. These notes were issued under a $1.5 billion debt shelf prospectus filed in Canada in March 2007.

On January 9, 2009, the Company issued Senior Unsecured Notes of US$750 million and US$1.25 billion maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. The proceeds from these notes are expected to be used to partially fund TransCanada's capital projects and retire mature debt obligations, and for general corporate purposes. These notes were issued under a US$3.0 billion debt shelf prospectus filed in January 2009. Following these issues, the Company has unutilized capacity of US$1.0 billion remaining under its January 2009 U.S. debt shelf prospectus.

In August 2008, TransCanada issued $500 million of Medium-Term Notes maturing in August 2013 and bearing interest at 5.05 per cent. The proceeds from these notes were used to partially fund the Alberta System's capital program and for general corporate purposes. These notes were issued under the debt shelf prospectus filed in Canada in March 2007.

In August 2008, TransCanada issued US$850 million and US$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. The proceeds from these notes were used to partially fund the Ravenswood acquisition and for general corporate purposes. These notes were issued under the September 2007 debt shelf prospectus filed in the U.S. Following these issuances, the Company had fully utilized the capacity of its September 2007 U.S. debt shelf prospectus.

In June 2008, the Company retired $256 million of 5.84 per cent Medium-Term Notes and a $100 million 11.85 per cent debenture. In January 2008, the Company retired $105 million of 6.0 per cent Medium-Term Notes.

2007 Long-Term Debt Financing Activities

In 2007, TransCanada issued Long-Term Debt of $2.6 billion and Junior Subordinated Notes of US$1.0 billion, and its proportionate share of Long-Term Debt issued by joint ventures was $142 million. The Company also reduced its Long-Term Debt by $1.1 billion, its Notes Payable by $46 million and its proportionate share of the Long-Term Debt of Joint Ventures by $157 million.

In October 2007, TransCanada issued US$1.0 billion of Senior Unsecured Notes under a US$2.5 billion debt shelf prospectus filed in the U.S. in September 2007. These notes mature on October 15, 2037 and bear interest at a rate of 6.20 per cent.

In July 2007, TransCanada exercised its rights to redeem the US$460 million 8.25 per cent Preferred Securities due 2047. The Preferred Securities were redeemed for cash, at par, as part of a settlement on the Canadian Mainline. The foreign exchange gain realized on redemption of the securities will flow through to Canadian Mainline shippers over the five-year period of the settlement.

In April 2007, the Company issued US$1.0 billion of Junior Subordinated Notes, maturing in 2067 and bearing interest of 6.35 per cent per year until May 15, 2017, when interest will convert to a floating interest rate of three-month LIBOR plus 221 basis points. The Junior Subordinated Notes are subordinated to all existing and future senior indebtedness, are effectively subordinated to all indebtedness and obligations of the Company and are callable at the Company's option at any time on or after May 15, 2017 at the principal amount plus accrued and unpaid interest.

In April 2007, Northern Border increased its five-year bank facility to US$250 million from US$175 million. A portion of the bank facility was drawn to refinance US$150 million of Senior Notes that matured on May 1, 2007, with the balance available to fund Northern Border's ongoing operations.

In March 2007, ANR Pipeline voluntarily withdrew the New York Stock Exchange listing of its 9.625 per cent debentures due 2021, 7.375 per cent debentures due 2024, and 7.0 per cent debentures due 2025. With the delisting, ANR Pipeline deregistered these securities with the SEC.

In February 2007, the Company established a US$1.0 billion committed, unsecured credit facility, consisting of a US$700 million five-year term loan and a US$300 million five-year, extendible revolving facility. The Company utilized US$1.0 billion from this facility and an additional US$100 million from an existing demand line to partially finance the ANR acquisition and increased ownership in Great Lakes, as well as its additional investment in PipeLines LP. The revolving portion of the committed facility and the draw on the demand line were subsequently repaid. In 2008, the maturity date of the revolving portion of the facility was extended to February 2013.

In February 2007, PipeLines LP increased the size of its syndicated revolving credit and term loan facility in connection with its Great Lakes acquisition. The amount available under the facility increased to US$950 million from US$410 million and consisted of a US$700 million senior term loan and a US$250 million senior revolving credit facility, with US$194 million of the available senior term loan amount being terminated upon closing of the Great Lakes acquisition.

In October 2007, the Company retired $150 million of 6.15 per cent Medium-Term Notes. In February 2007, the Company retired $275 million of 6.05 per cent Medium-Term Notes.

2006 Long-Term Debt Financing Activities
In 2006, the Company issued Long-Term Debt of $2.1 billion and reduced its Long-Term Debt by $729 million, its Notes Payable by $495 million and its proportionate share of the Long-Term Debt of Joint Ventures by a net amount of $14 million. In January 2006, the Company issued $300 million of 4.3 per cent five-year Medium-Term Notes due 2011. In March 2006, the Company issued US$500 million of 5.85 per cent Senior Unsecured Notes due 2036. In October 2006, TransCanada issued $400 million of 4.65 per cent Medium-Term Notes due 2016.

In April 2006, PipeLines LP borrowed US$307 million under its unsecured credit facility to finance the cash portion of its acquisition of an additional 20 per cent interest in Northern Border. In December 2006, the credit facility was repaid in full and replaced with a US$410 million syndicated revolving credit and term loan agreement, a portion of which was utilized to finance the acquisition of additional interests in Tuscarora. In February 2007, PipeLines LP increased the size of this facility, as discussed above.

2008 Equity Financing Activities
In July 2008, the Company filed a short form base shelf prospectus in Canada and the U.S. qualifying for issuance $3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until August 2010. This shelf replaced the base shelf prospectus filed in January 2007.

In fourth quarter 2008, the Company completed a public offering of common shares at a purchase price of $33.00 per share. The entire issue of 35.1 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.2 billion. The proceeds of the offering were used by TransCanada to partially fund its capital projects, including Keystone, for general corporate purposes and to repay short-term indebtedness. These common shares were issued under the base shelf prospectus filed in July 2008.

In May 2008, the Company completed a public offering of common shares at a purchase price of $36.50 per share. The entire issue of 34.7 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.3 billion. These proceeds were used to partially fund the Ravenswood acquisition and the Company's capital projects, and for general corporate purposes. These common shares were issued under the base shelf prospectus filed in January 2007.

Commencing in 2007, TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount to participants in the Company's DRP. Under this plan, eligible shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. The DRP shares are provided to the participants at a discount to the average market price in the five days before dividend payment. The discount was set at two per cent commencing with the dividend payable in April 2007 and was increased to three per cent for the dividend payable in January 2009. Prior to the April 2007 dividend, TransCanada purchased shares on the open market and provided them to DRP participants at cost. The Company reserves the right to alter the discount or return to purchasing shares on the open market at any time. Dividends of $218 million were paid in 2008 through the issuance of six million common shares from treasury in accordance with the DRP.

2007 Equity Financing Activities
In first quarter 2007, the Company issued 45.4 million common shares at a purchase price of $38.00 per share under a base shelf prospectus filed in Canada and the U.S. in January 2007, resulting in gross proceeds of $1.7 billion. The proceeds were used towards financing the acquisition of ANR and Great Lakes.

In February 2007, PipeLines LP completed a private placement offering of 17.4 million common units at a purchase price of US$34.57 per unit. TransCanada acquired 50 per cent of the units for US$300 million and invested an additional US$12 million to maintain its general partnership ownership interest in PipeLines LP. The total private placement plus TransCanada's additional investment resulted in gross proceeds to PipeLines LP of US$612 million, which were used to partially finance its Great Lakes acquisition.

Dividends

Cash dividends on common shares amounting to $577 million were paid in 2008 compared to $546 million in 2007 and $617 million in 2006. The increase in dividends in 2008 compared to 2007 was primarily due to a greater number of shares outstanding and an increase in the dividend per share amount in 2008, partially offset by the issuance of $218 million of common shares under the DRP, in lieu of cash dividends. The reduction in 2007 compared to 2006 was primarily due to the Company's issuance of $157 million of common shares from treasury under the DRP, which more than offset the impact of the higher dividend per share amount.

In January 2009, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.38 per share from $0.36 per share for the quarter ending March 31, 2009. This was the ninth consecutive year in which the dividend was increased beginning with the dividend of $0.20 per share declared in fourth quarter 2000 and represents a 90 per cent increase in the dividend over this period.

Issuer Ratings

TransCanada's issuer rating assigned by Moody's Investors Service (Moody's) is Baa1 with a stable outlook. TransCanada PipeLines Limited's (TCPL) senior unsecured debt is rated A with a stable outlook by DBRS, A3 with a stable outlook by Moody's, and A− with a stable outlook by Standard and Poor's.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

At December 31, 2008, the Company had $16.2 billion of total Long-Term Debt and $1.2 billion of Junior Subordinated Notes, compared to $12.9 billion of total Long-Term Debt and $1.0 billion of Junior Subordinated Notes at December 31, 2007. TransCanada's share of the total debt of joint ventures, including capital lease obligations, was $1.1 billion at December 31, 2008, compared to $903 million at December 31, 2007. Total Notes Payable, including TransCanada's proportionate share of the notes payable of joint ventures, were $1.7 billion at December 31, 2008, compared to $421 million at December 31, 2007. TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power and to the performance obligations of Bruce Power and certain other partially owned entities.

CONTRACTUAL OBLIGATIONS
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[1]	18,208	980	1,787	2,684	12,757
Capital lease obligations	235	13	25	38	159
Operating leases[2]	403	28	56	66	253
Purchase obligations	12,246	3,926	2,595	1,761	3,964
Other long-term liabilities reflected on the balance sheet	610	12	29	34	535
Total contractual obligations	31,702	4,959	4,492	4,583	17,668

(1) Includes Junior Subordinated Notes.

(2) Represents future annual payments, net of sub-lease receipts, for various premises, services and equipment. The operating lease agreements for premises, services and equipment expire at various dates through 2035, with an option to renew certain lease agreements for one to ten years.

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from the above table, as these payments are dependent upon plant availability, among other factors. The amount of power purchased under the PPAs in 2008 was $471 million (2007 – $440 million; 2006 – $499 million).

At December 31, 2008, scheduled principal repayments and interest payments related to long-term debt and the Company's proportionate share of the long-term debt of joint ventures were as follows:

PRINCIPAL REPAYMENTS
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[1]	16,154	786	1,545	2,550	11,273
Junior subordinated notes	1,213	–	–	–	1,213
Long-term debt of joint ventures	841	194	242	134	271
Total principal repayments	18,208	980	1,787	2,684	12,757

[1] Includes Junior Subordinated Notes.

INTEREST PAYMENTS
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Interest payments on long-term debt	14,508	1,072	1,995	1,794	9,647
Interest payments on junior subordinated notes	662	78	156	156	272
Interest payments on long-term debt of joint ventures	328	61	76	56	135
Total interest payments	15,498	1,211	2,227	2,006	10,054

At December 31, 2008, the Company's approximate future purchase obligations were as follows:

PURCHASE OBLIGATIONS[1]
Year ended December 31 *(millions of dollars)*

		Payments Due by Period			
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Pipelines					
Transportation by others[2]	931	260	396	199	76
Capital expenditures[3][4]	2,317	2,092	155	70	–
Other	6	3	2	1	–
Energy					
Commodity purchases[5]	6,711	945	1,394	1,284	3,088
Capital expenditures[3][6]	1,049	509	456	61	23
Other[7]	1,133	88	151	124	770
Corporate					
Information technology and other	99	29	41	22	7
Total purchase obligations	12,246	3,926	2,595	1,761	3,964

(1) The amounts in this table exclude funding contributions to pension plans and funding to the APG.

(2) Rates are based on known 2009 levels. Beyond 2009, demand rates are subject to change. The contract obligations in the table are based on known or contracted demand volumes only and exclude commodity charges incurred when volumes flow.

(3) Amounts are estimates and are subject to variability based on timing of construction and project enhancements. The Company expects to fund capital projects with cash from operations and, if necessary, new debt and equity.

(4) Primarily consists of capital expenditures related to TransCanada's share of the construction costs of Keystone, North Central Corridor and other pipeline projects.

(5) Commodity purchases include fixed and variable components. The variable components are estimates and are subject to variability in plant production, market prices and regulatory tariffs.

(6) Primarily consists of capital expenditures related to TransCanada's share of the construction costs of Coolidge, Bruce Power, the remaining Cartier Wind projects, Halton Hills and Portlands Energy.

(7) Includes estimates of certain amounts that are subject to change depending on plant fired hours, the consumer price index, actual plant maintenance costs, plant salaries, and changes in regulated rates for transportation.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

In 2009, TransCanada expects to make funding contributions to the Company's pension and other post-retirement benefit plans in the amount of approximately $140 million and $27 million, respectively. This represents an increase from total funding contributions of $90 million in 2008 and is attributable primarily to significantly reduced investment performance and plan experience being different than expectations. TransCanada's proportionate share of funding contributions expected to be made by joint ventures to their respective pension and other post-retirement benefit plans in 2009 is approximately $37 million and $4 million, respectively, compared to actual total contributions of $42 million in 2008.

The next actuarial valuation for the Company's pension and other post-retirement benefit plans is expected to be carried out as at January 1, 2010. Primarily as a result of the significantly lower performance of the pension plan assets in 2008, it is expected that funding requirements for these plans could continue at the anticipated 2009 level for the next several years to amortize solvency deficiencies in addition to normal costs. The Company's net benefit cost is expected to remain at 2008 levels. However, the net benefit cost and the amount of funding contributions received will be dependent on various factors, including future investment returns achieved on plan assets, the level of interest rates, changes to plan design and actuarial assumptions, actual plan experience versus projections and amendments to pension plan regulations and legislation. Increases in the level of required plan funding are not expected to have a material impact on the Company's liquidity.

Bruce Power
Bruce A has signed commitments to third-party suppliers related to refurbishing and restarting Units 1 and 2 and refurbishing Units 3 and 4 to extend their operating life. TransCanada's share of these signed commitments, which extend over the three-year period ending December 31, 2011, are as follows:

Year ended December 31 *(millions of dollars)*	
2009	204
2010	49
2011	2
	255

Aboriginal Pipeline Group
Under its agreement with the APG, TransCanada agreed to finance the APG's one-third share of the MGP project's predevelopment costs. These costs are currently forecast to be between $150 million and $200 million, on a cumulative basis, depending on the pace of project development. As at December 31, 2008, the Company had advanced $140 million of this total. This agreement is discussed further in the "Pipelines – Opportunities and Developments" section of this MD&A.

Contingencies
In April 2008, the Ontario Court of Appeal dismissed an appeal filed by the Canadian Alliance of Pipeline Landowners' Associations (CAPLA). CAPLA filed the appeal as a result of a decision by the Ontario Superior Court in November 2006 to dismiss CAPLA's class action lawsuit against TransCanada and Enbridge Inc. for damages alleged to have arisen from the creation of a control zone within 30 metres of a pipeline pursuant to Section 112 of the *National Energy Board Act*. The Ontario Court of Appeal's decision is final and binding as CAPLA did not seek any further appeal within the time frame allowed.

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2008, the Company had recorded liabilities of approximately $86 million representing the Company's estimate of the amount it expects to expend to remediate certain sites. However, additional liabilities may be incurred as more assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees
TransCanada, Cameco Corporation and BPC have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, a lease agreement and contractor services. The guarantees have terms ranging from one year ending in 2010 to perpetuity. In addition, TransCanada and BPC have severally guaranteed one-half of certain contingent financial obligations related to an agreement with the OPA to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated at December 31, 2008 to range from $711 million to a maximum of $750 million. The fair value of these guarantees is estimated to be $17 million.

The Company and its partners in certain jointly owned entities have severally as well as jointly and severally guaranteed the financial performance of these entities related primarily to construction projects, redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these guarantees was estimated at December 31, 2008 to range from $688 million to a maximum of $1.4 billion. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners. Deferred Amounts includes $9 million for the fair value of these joint and several guarantees.

TransCanada has guaranteed a subsidiary's equity undertaking to support the payment, under certain conditions, of principal and interest on US$43 million of the public debt obligations of TransGas. The Company has a 46.5 per cent interest in TransGas. Under the terms of a shareholder agreement, TransCanada and another major multinational company may be required to severally fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement would convert into share capital of TransGas. The Company's potential exposure is contingent on the impact any change of law would have on the ability of TransGas to service the debt. There has been no change in applicable law since the issuance of debt in 1995 and, thus, no exposure for TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

FINANCIAL RISKS AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk, and liquidity risk. TransCanada engages in risk management activities with the primary objective being to protect earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee. The Board of Directors also has a Governance Committee that assists in overseeing the risk management activities of TransCanada. The Governance Committee monitors, reviews with management and makes recommendations related to TransCanada's risk management programs and policies on an ongoing basis.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management policy to manage exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.

- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and oil products. A number of strategies are used to mitigate these exposures, including the following:

- Subject to the Company's overall risk management policies, the Company commits a significant portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.
- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sales price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfill the Company's power sales commitments is purchased with contracts or fulfilled through power generation, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions and derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

TransCanada manages its exposure to seasonal natural gas price spreads in its natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to price movements of natural gas. Fair value adjustments recorded each period on proprietary natural gas storage inventory and these forward contracts may not be representative of the amounts that will be realized on settlement.

Natural Gas Inventory Price Risk

At December 31, 2008, $76 million (2007 – $190 million) of proprietary natural gas inventory was included in Inventories. TransCanada measures its proprietary natural gas inventory held in storage at the one-month forward price for natural gas less selling costs. The Company did not have any proprietary natural gas inventory held in storage prior to April 2007. In 2008, the net change in fair value of proprietary natural gas held in inventory was a net unrealized loss of $7 million (2007 – nil), which was recorded as a decrease to Revenue and Inventory. In 2008, the net change in fair value of natural gas forward purchases and sales contracts was a net unrealized gain of $7 million (2007 – $10 million) which was included in Revenues.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and/or market interest rates.

A portion of TransCanada's earnings from its Pipelines and Energy operations is generated in U.S. dollars and is subject to currency fluctuations. The performance of the Canadian dollar relative to the U.S. dollar can affect TransCanada's earnings. This foreign exchange impact is offset by certain related debt and financing costs being denominated in U.S. dollars and by the Company's hedging activities. Due to its increased U.S. operations, TransCanada has a greater exposure to U.S. currency fluctuations than in prior years.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposure of the Canadian Mainline, Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. These gains and losses are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt, which subjects it to interest rate cash flow risk. The Company uses a combination of forwards, interest rate swaps and options to manage its exposure to this risk.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, forward foreign exchange contracts, cross-currency interest rate swaps and foreign exchange options. At December 31, 2008, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.2 billion (US$5.9 billion) (2007 – $4.7 billion (US$4.7 billion)) and a fair value of $5.9 billion (US$4.8 billion) (2007 – $4.8 billion (US$4.8 billion)). In January 2009, the Company issued an additional US$2.0 billion of long-term debt and designated it as a hedge of the net U.S. dollar investment in foreign operations. At December 31, 2008, $254 million was included in Deferred Amounts for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amount for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability) *December 31 (millions of dollars)*	**2008** **Fair Value**	**2008** **Notional or Principal Amount**	2007 Fair Value	2007 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2009 to 2014)	**(218)**	**U.S. 1,650**	77	U.S. 350
U.S. dollar forward foreign exchange contracts (maturing 2009)	**(42)**	**U.S. 2,152**	(4)	U.S. 150
U.S. dollar options (maturing 2009)	**6**	**U.S. 300**	3	U.S. 600
	(254)	**U.S. 4,102**	76	U.S. 1,100

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using master netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that these processes will protect it against all losses.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-credit worthy counterparties.

During the deterioration of global financial markets in 2008, TransCanada continued to closely monitor and reassess the creditworthiness of its counterparties, including financial institutions. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it is deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market risk and counterparty credit risk when making business decisions.

Certain subsidiaries of Calpine filed for bankruptcy protection in both Canada and the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland Natural Gas Transmission System (PNGTS) reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and PNGTS received initial distributions of 9.4 million common shares and 6.1 million common shares of Calpine, respectively, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were subsequently sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NOVA Gas Transmission Limited and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and will be passed on to shippers on these systems. At December 31, 2008, $22 million remained in regulatory liabilities for these claims.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure that, under both normal and stressed conditions, it always has sufficient cash and credit facilities to meet its obligations when due without incurring unacceptable losses or damage to the Company's reputation.

Management forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets. The Company's liquidity and cash flow management is also discussed in the "Liquidity and Capital Resources" and "Contractual Obligations" sections of this MD&A.

Fair Values

The fair value of financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts approximates their carrying amounts due to the nature of the item and/or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates. The fair value of power, natural gas and oil products derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes are used. Credit risk has been taken into consideration when calculating fair values.

Valuation techniques that refer to observable market data or estimated market prices may also be used to calculate fair value. These include comparisons with similar instruments that have observable market prices, option pricing models and other valuation techniques commonly used by market participants. Fair values determined using valuation models require the use of assumptions about the amount and timing of estimated future cash flows and discount rates. In making these assumptions, the Company looks primarily to readily observable external market input factors such as interest rate yield curves, currency rates and price and rate volatilities, as applicable.

The fair value of the Company's Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments and, when such information was not available, was estimated by discounting future payments of interest and principal at estimated interest rates that were made available to the Company.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

	2008		2007	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**1,308**	**1,308**	504	504
Accounts receivable and other assets[2][3]	**1,404**	**1,404**	1,231	1,231
Available-for-sale assets[2]	**27**	**27**	17	17
	2,739	**2,739**	1,752	1,752
Financial Liabilities[1][3]				
Notes payable	**1,702**	**1,702**	421	421
Accounts payable and deferred amounts[4]	**1,372**	**1,372**	1,193	1,193
Accrued interest	**359**	**359**	261	261
Long-term debt and junior subordinated notes	**17,367**	**16,152**	13,908	15,334
Long-term debt of joint ventures	**1,076**	**1,052**	903	937
Other long-term liabilities of joint ventures[4]	**–**	**–**	60	60
	21,876	**20,637**	16,746	18,206

(1) Consolidated Net Income in 2008 and 2007 included unrealized gains or losses of nil for the fair value adjustments to each of these financial instruments.

(2) At December 31, 2008, the Consolidated Balance Sheet included financial assets of $1,257 million (2007 – $1,018 million) in Accounts Receivable and $174 million (2007 – $230 million) in Other Assets.

(3) Recorded at amortized cost, except for certain Long-Term Debt which is adjusted to fair value.

(4) At December 31, 2008, the Consolidated Balance Sheet included financial liabilities of $1,350 million (2007 – $1,175 million) in Accounts Payable and $22 million (2007 – $78 million) in Deferred Amounts.

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments is as follows:

	2008				
December 31 (all amounts in millions unless otherwise indicated)	**Power**	**Natural Gas**	**Oil Products**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading					
Fair Values[1]					
Assets	$132	$144	$10	$41	$57
Liabilities	$(82)	$(150)	$(10)	$(55)	$(117)
Notional Values					
Volumes[2]					
Purchases	4,035	172	410	–	–
Sales	5,491	162	252	–	–
Canadian dollars	–	–	–	–	1,016
U.S. dollars	–	–	–	U.S. 479	U.S. 1,575
Japanese yen (in billions)	–	–	–	JPY 4.3	–
Cross-currency	–	–	–	227/U.S. 157	–
Net unrealized gains/(losses) in the year[3]	$24	$(23)	$1	$(9)	$(61)
Net realized gains/(losses) in the year[3]	$23	$(2)	$1	$6	$13
Maturity dates	2009-2014	2009-2011	2009	2009-2012	2009-2018
Derivative Financial Instruments in Hedging Relationships[4][5]					
Fair Values[1]					
Assets	$115	$–	$–	$2	$8
Liabilities	$(160)	$(18)	$–	$(24)	$(122)
Notional Values					
Volumes[2]					
Purchases	8,926	9	–	–	–
Sales	13,113	–	–	–	–
Canadian dollars	–	–	–	–	50
U.S. dollars	–	–	–	U.S. 15	U.S. 1,475
Cross-currency	–	–	–	136/U.S. 100	–
Net realized (losses)/gains in the year[3]	$(56)	$15	$–	$–	$(10)
Maturity dates	2009-2014	2009-2011	–	2009-2013	2009-2019

(1) Fair value is equal to the carrying value of these derivatives.

(2) Volumes for power, natural gas and oil products derivatives are in gigawatt hours, billion cubic feet and thousands of barrels, respectively.

(3) All power, natural gas and oil products realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

(4) All hedging relationships are designated as cash flow hedges except for interest-rate derivative financial instruments designated as fair value hedges with a fair value of $8 million. In 2008, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2008, Net Income included losses of $6 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2008, there were no gains or losses included in Net Income for discontinued cash flow hedges.

The anticipated timing of settlement of the derivative contracts assumes no changes in commodity prices, interest rates and foreign exchange rates from December 31, 2008. Actual settlements will vary based on changes in these factors. The anticipated timing of settlement of these contracts is as follows:

(millions of dollars)	Total	2009	2010 and 2011	2012 and 2013	2014 and Thereafter
Derivative financial instruments held for trading	(30)	38	(46)	(14)	(8)
Derivative financial instruments in hedging relationships	(199)	(68)	(65)	(43)	(23)
	(229)	(30)	(111)	(57)	(31)

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments is as follows:

December 31 *(all amounts in millions unless otherwise indicated)*	2007 Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading				
Fair Values[1]				
Assets	$55	$43	$11	$23
Liabilities	$(44)	$(19)	$(79)	$(18)
Notional Values				
Volumes[2]				
Purchases	3,774	47	–	–
Sales	4,469	64	–	–
Canadian dollars	–	–	–	615
U.S. dollars	–	–	U.S. 484	U.S. 550
Japanese yen (in billions)	–	–	JPY 9.7	–
Cross-currency	–	–	227/U.S. 157	–
Net unrealized gains/(losses) in the year[3]	$16	$(10)	$8	$(5)
Net realized (losses)/gains in the year[3]	$(8)	$47	$39	$5
Maturity dates	2008-2016	2008-2010	2008-2012	2008-2016
Derivative Financial Instruments in Hedging Relationships[4][5]				
Fair Values[1]				
Assets	$135	$19	$–	$2
Liabilities	$(104)	$(7)	$(62)	$(16)
Notional Values				
Volumes[2]				
Purchases	7,362	28	–	–
Sales	16,367	4	–	–
Canadian dollars	–	–	–	150
U.S. dollars	–	–	U.S. 113	U.S. 875
Cross-currency	–	–	136/U.S. 100	–
Net realized (losses)/gains in the year[3]	$(29)	$18	$–	$3
Maturity dates	2008-2013	2008-2010	2008-2013	2008-2013

(1) Fair value is equal to the carrying value of these derivatives.

(2) Volumes for power and natural gas derivatives are in gigawatt hours and billion cubic feet, respectively.

(3) All power and natural gas realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

(4) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $2 million. In 2007, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2007, Net Income included gains of $7 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2007, Net Income included a loss of $4 million for the changes in fair value of an interest-rate cash flow hedge that was reclassified as a result of discontinuance of cash flow hedge accounting when the anticipated transaction was not likely to occur by the end of the originally specified time period.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 (millions of dollars)	**2008**	2007
Current		
Other current assets	**318**	160
Accounts payable	**(298)**	(144)
Long-term		
Other assets	**191**	204
Deferred amounts	**(694)**	(205)

OTHER RISKS

Development Projects and Acquisitions

TransCanada continues to focus on growing its Pipelines and Energy operations through greenfield development projects and acquisitions. TransCanada capitalizes costs incurred on certain of its projects during the development period prior to construction when the project meets specific criteria and is expected to proceed through to completion. The related capital costs of a project that does not proceed through to completion would be expensed at the time it is discontinued. There is a risk with respect to TransCanada's acquisition of assets and operations that certain commercial opportunities and operational synergies may not materialize as expected and would subsequently be subject to an impairment writedown.

Health, Safety and Environment Risk Management

Health, safety and environment (HS&E) is a priority in all of TransCanada's operations and is guided by the Company's HS&E Commitment Statement. The Commitment Statement outlines guiding principles for a safe and healthy environment for TransCanada's employees, contractors and the public, and that strive to protect the environment. All employees are held responsible and accountable for HS&E performance. The Company is committed to being an industry leader in conducting its business so that it meets or exceeds all applicable laws and regulations, and minimizes risk to people and the environment. The Company is committed to tracking and improving its HS&E performance, and to promoting safety on and off the job in the belief that all occupational injuries and illnesses are preventable. TransCanada endeavours to do business with companies and contractors that share its perspective on HS&E performance and to influence them to improve their collective performance. TransCanada is committed to respecting the diverse environments and cultures in which it operates and to supporting open communication with the public, policy makers, scientists and public interest groups with whom it shares stewardship of the world it inhabits.

TransCanada is committed to ensuring compliance with its internal policies and regulated requirements. The HS&E Committee of TransCanada's Board of Directors monitors compliance with the Company's HS&E corporate policy through regular reporting. TransCanada's HS&E management system is modeled on the International Organization of Standardization's (ISO) standard for environmental management systems, ISO 14001, and focuses resources on the areas of significant risk to the organization's HS&E business activities. Management is informed regularly of all important HS&E operational issues and initiatives through formal reporting processes. TransCanada's HS&E management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in November 2006. The HS&E management system also is subject to ongoing internal review to ensure that it remains effective as circumstances change.

In 2008, employee and contractor health and safety performance continued to be a top priority. TransCanada's assets were highly reliable and there were no incidents that were material to TransCanada's operations.

The safety and integrity of the Company's pipelines is a top priority. The Company expects to spend approximately $185 million in 2009 for pipeline integrity on its wholly owned pipelines, which is higher than the amount spent in 2008 primarily due to increased levels of in-line pipeline inspection on all systems. Under the approved regulatory models in Canada, pipeline integrity expenditures on NEB- and AUC-regulated pipelines are treated on a flow-through basis and, as a result, have no impact on TransCanada's earnings. Expenditures on the GTN System are also recovered through a cost recovery mechanism in its rates. Pipeline safety in 2008 continued to be very good, as TransCanada experienced only one small-diameter pipeline failure in a remote part of east central Alberta. The break resulted in minimal impact with no injuries or property damage. Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment, and is consistent with previous years.

Environment

TransCanada's facilities are subject to various federal, provincial, state and local statutes and regulations, including requirements to establish compliance and remediation obligations. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, some of which have been designated as Superfund sites by the U.S. Environmental Protection Agency under the *Comprehensive Environmental Response, Compensation and Liability Act*, and with damage claims arising out of the contamination of properties or impact on natural resources. It is not possible for the Company to estimate exactly the amount and timing of all future expenditures related to environmental matters due to:

- uncertainties in estimating pollution control and clean-up costs, including sites where only preliminary site investigation or agreements have been completed;
- the potential discovery of new sites or additional information at existing sites;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the evolving nature of environmental laws and regulations, including the interpretation and enforcement thereof; and
- the potential for litigation on existing or discontinued assets.

Environmental risks from TransCanada's operating facilities typically include: air emissions, such as nitrogen oxides, particulate matter and greenhouse gases; potential impacts on land, including land reclamation or restoration following construction; the use, storage or release of chemicals or hydrocarbons; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge. Environmental controls including physical design, programs, procedures and processes are in place to effectively manage these risks. TransCanada has ongoing inspection programs designed to keep all of its facilities in compliance with environmental requirements and the Company is confident that its systems are in material compliance with the applicable requirements.

In 2008, TransCanada conducted environmental risk assessments and remediation work, resulting in total costs of approximately $7 million and US$6 million for work conducted on TransCanada's Canadian and U.S. facilities, respectively. TransCanada also conducted various retirement, reclamation and restoration work in 2008, which resulted in total costs of approximately $7 million. At December 31, 2008, TransCanada had recorded liabilities of approximately $86 million for compliance and remediation obligations. The Company believes it has considered all necessary contingencies and established appropriate reserves for environmental liabilities, however, there is the risk that unforeseen matters may arise requiring the Company to set aside additional amounts.

TransCanada is not aware of any material outstanding orders, claims or lawsuits against the Company in relation to the release or discharge of any material into the environment or in connection with environmental protection.

North American climate change policy continues to evolve at regional and national levels. While recent political and economic events may significantly affect the scope and timing of new measures that are put in place, TransCanada anticipates that most of the company's facilities in Canada and the U.S. will be captured under future regional and/or federal climate change regulations to manage industrial greenhouse gas (GHG) emissions.

In 2008, the Company owned assets in three regions affected by climate change policy measures related to industrial emissions. In Alberta, the Specified Gas Emitters Regulation, which came into effect in 2007, requires industrial facilities to reduce GHG emissions intensities by 12 per cent. TransCanada's Alberta-based pipeline and power facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with which TransCanada has commercial arrangements. The Company's total cost of compliance incurred by the Alberta-based facilities for the period from July 2007 to December 2007 was approximately $12 million. Costs for 2008 compliance are estimated to be $28 million and will be finalized when compliance reports are submitted in March 2009. Compliance costs of the Alberta System are recovered through tolls paid by customers. Recovery of compliance costs for the Company's power generation facilities and interests in Alberta is partially achieved through contracts and the impact of increased operating costs on Alberta power market prices.

The hydrocarbon royalty in Québec is collected by the natural gas distributor on behalf of the Québec government via a green fund contribution charge on gas consumed. In 2008, the cost pertaining to the Bécancour facility arising from the hydrocarbon royalty was less than $1 million as a result of an agreement between TransCanada and Hydro-Québec to temporarily suspend the facility's power generation. The cost is expected to increase when the plant returns to service in 2010.

B.C.'s carbon tax, which came into effect in mid-2008, applies to carbon dioxide (CO_2) emissions arising from fossil fuel combustion. Compliance costs for fuel combustion at the Company's compressor and meter stations in B.C. are recovered through tolls paid by customers. Costs related to the carbon tax for 2008 were $1 million. This cost is expected to increase over the next four years as the tax charge per tonne of CO_2 increases by $5 per tonne annually from the initial tax rate of $10 per tonne.

TransCanada has assets located in Ontario and Manitoba, where the provincial governments have announced climate change strategies that will impact industrial sources of GHG emissions. The details of these programs and how they will align with the Canadian government's climate change policies are still uncertain.

The Canadian government has expressed interest in pursuing the development of a North American cap and trade system for GHG emissions. In April 2007, the Government of Canada released the Regulatory Framework for Air Emissions (Framework). The Framework outlines short-, medium- and long-term objectives for managing both GHG emissions and air pollutants in Canada. TransCanada expects a number of its facilities will be affected by pending federal climate change regulations that will be put in place to meet the Framework's objectives. It is not known at this time whether the impacts from the pending regulations will be material as the draft regulations have not yet been released. It is uncertain how the Framework will fit within a North American cap and trade system and what the specific requirements for industrial emitters will be.

Climate change is a strategic issue for the new U.S. government administration and federal policy to manage domestic GHG emissions is expected to be a priority. Seven western states and four Canadian provinces are focused on the implementation of a cap and trade program under the Western Climate Initiative (WCI). Northeastern states that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap and trade program for electricity generators effective January 1, 2009. Participants in the Midwestern Greenhouse Gas Reduction Accord, which involves six states and one province, are developing a regional strategy for reducing members' GHG emissions that will include a multi-sector cap and trade mechanism.

The Company anticipates a number of its facilities will be affected by these legislative initiatives. Under the RGGI, both the Ravenswood and OSP facilities will be required to submit allowances by December 31, 2011. It is expected that the costs will be recovered from the market and the net impact to TransCanada will be minimal. Company assets located in regions affected by the WCI and Midwestern Greenhouse Gas Reduction Accord and in California are most likely to be covered by GHG reduction measures put in place, however, the level of impact is uncertain as key policy details remain outstanding.

TransCanada monitors climate change policy developments and, when warranted, participates in policy discussions in jurisdictions where the Company has operations. The Company is also continuing its programs to manage GHG emissions from its facilities and to evaluate new processes and technologies that result in improved efficiencies and lower GHG emission rates.

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures
Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws. The information is accumulated and communicated to management, including the President and Chief Executive Officer and the Chief Financial Officer, to allow timely decisions regarding required disclosure.

As at December 31, 2008, an evaluation of the effectiveness of TransCanada's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC was carried out under the supervision and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of TransCanada's disclosure controls and procedures were effective as at December 31, 2008.

Management's Annual Report on Internal Control over Financial Reporting
Internal control over financial reporting is a process designed by or under the supervision of senior management and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with Canadian GAAP, including a reconciliation to U.S. GAAP.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company acquired Ravenswood in August 2008 and began consolidating the operations of Ravenswood from that date. Management has excluded this business from its evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2008. The net income attributable to this business represented less than one per cent of the Company's consolidated net income for the year ended December 31, 2008, and its aggregate total assets represented approximately nine per cent of the Company's consolidated total assets as at December 31, 2008.

Based on this evaluation, management concluded that internal control over financial reporting is effective as at December 31, 2008, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2008, there was no change in TransCanada's internal control over financial reporting that materially affected or is reasonably likely to materially affect TransCanada's internal control over financial reporting.

CEO and CFO Certifications
TransCanada's President and Chief Executive Officer and Chief Financial Officer have filed with the SEC and the Canadian securities regulators certifications regarding the quality of TransCanada's public disclosures relating to its fiscal 2008 reports filed with the SEC and the Canadian securities regulators.

SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

To prepare financial statements that conform with Canadian GAAP, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. The Company believes the following accounting policies and estimates require it to make assumptions about highly uncertain matters and changes in these estimates could have a material impact to the Company's financial information.

Regulated Accounting
The Company accounts for the impacts of rate regulation in accordance with GAAP. Three criteria must be met to use these accounting principles:

- the rates for regulated services or activities must be subject to approval by a regulator;
- the regulated rates must be designed to recover the cost of providing the services or products; and
- it must be reasonable to assume that rates set at levels to recover the cost can be charged to and will be collected from customers in view of the demand for services or products and the level of direct and indirect competition.

The Company's management believes all three of these criteria have been met with respect to each of the regulated natural gas pipelines accounted for using regulated accounting principles. The most significant impact from the use of these accounting principles is that the timing of recognition of certain expenses and revenues in the regulated businesses may differ from that otherwise expected under GAAP in order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls.

Effective January 1, 2009, the Company's accounting for its future income taxes recorded on rate-regulated operations will change as discussed in the "Accounting Changes" section of this MD&A.

Financial Instruments and Hedges

Financial Instruments
Effective January 1, 2007, the Company adopted the accounting requirements for the Canadian Institute of Chartered Accountants (CICA) Handbook Sections 1530 "Comprehensive Income", 3855 "Financial Instruments – Recognition and Measurement", and 3865 "Hedges". Effective December 31, 2007, the Company adopted the accounting requirements for CICA Handbook Sections 3862 "Financial Instruments – Disclosure", 3863 "Financial Instruments – Presentation", and 1535 "Capital Disclosures". Adjustments to the consolidated financial statements for 2007 were made on a prospective basis.

The CICA Handbook requires that all financial instruments initially be included on the balance sheet at their fair value. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments and loans and receivables.

Financial liabilities are classified as held for trading or other financial liabilities. The Company does not have any held-to-maturity investments.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in Revenues. Changes in the fair value of interest rate and foreign exchange rate held-for-trading instruments are recorded in Financial Charges and in Interest Income and Other, respectively.

The available-for-sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications. These instruments are accounted for initially at their fair value and changes to fair value are recorded through Other Comprehensive Income. Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as "loans and receivables" and are measured at amortized cost using the effective interest method, net of any impairment. Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method.

The recognition of gains and losses on the derivatives for the Canadian Mainline, Alberta System and Foothills exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of rate-regulated accounting are deferred in regulatory assets or regulatory liabilities.

Hedges

The CICA Handbook specifies the criteria that must be satisfied in order to apply hedge accounting and the accounting for each of the permitted hedging strategies, including: fair value hedges, cash flow hedges and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. The changes in fair value are recognized in Net Income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net Income.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in Other Comprehensive Income, while any ineffective portion is recognized in Net Income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Net Income during the periods when the variability in cash flows of the hedged item affects Net Income. Gains and losses on derivatives are reclassified immediately to Net Income from Accumulated Other Comprehensive Income when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. The gains and losses arising from the changes in fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as rate-regulated assets or liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains or losses are collected from or refunded to the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in Other Comprehensive Income and the ineffective portion is recognized in Net Income. The amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Net Income in the event the Company settles or otherwise reduces its investment in a foreign operation.

The fair value of financial instruments and hedges is primarily derived from market values adjusted for credit risk, which can fluctuate greatly from period to period. These changes in fair value can result in variability in net income as a result of recording these changes in fair value through earnings. The risks associated with fluctuations to earnings and cash flows for financial instruments and hedges are discussed further in the "Risk Management and Financial Instruments" section of this MD&A.

Depreciation and Amortization Expense

TransCanada's plant, property and equipment are depreciated on a straight-line basis over their estimated useful lives. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to 25 per cent. Metering and other plant equipment are depreciated at various rates. Major power generation and natural gas storage plant, equipment and structures in the Energy business are depreciated on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to ten per cent. Nuclear power generation assets under capital lease are initially recorded at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other equipment is depreciated at various rates. Corporate plant, property and equipment are depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Depreciation expense in 2008 was $1,189 million (2007 – $1,179 million) and is recorded in Pipelines and Energy. In Pipelines, depreciation rates are approved by regulators when applicable and depreciation expense is recoverable based on the cost of providing the services or products. If regulators permit recovery through rates, a change in the estimate of the useful lives of plant, property and equipment in the Pipelines segment will have no material impact on TransCanada's net income but will directly affect funds generated from operations.

Impairment of Long-Lived Assets and Goodwill

The Company reviews long-lived assets such as property, plant and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Goodwill is tested in the Pipelines and Energy segments for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial assessment is made by comparing the fair value of the operations, which includes goodwill, to the book values of each reporting unit. If this fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, an impairment charge is recorded.

These valuations are based on management's projections of future cash flows and, therefore, require estimates and assumptions with respect to:

- discount rates;
- commodity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies; and
- regulatory changes.

Significant changes in these assumptions could affect the Company's need to record an impairment charge.

ACCOUNTING CHANGES

FUTURE ACCOUNTING CHANGES

Rate-Regulated Operations

Effective January 1, 2009, the temporary exemption from CICA Handbook Section 1100 "Generally Accepted Accounting Principles", which permits the recognition and measurement of assets and liabilities arising from rate regulation, was withdrawn. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated entities. The Company has chosen to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's Financial Accounting Standard (FAS) 71 "Accounting for the Effects of Certain Types of Regulation". Accordingly, TransCanada will retain its current method of accounting for its rate-regulated operations, except that TransCanada will be required to recognize future income tax assets and liabilities instead of using the taxes payable method, and will record an offsetting adjustment to regulatory assets and liabilities. If the Company had adopted FAS 71 at December 31, 2008, additional future income tax liabilities and a regulatory asset in the amount of $1,434 million would have been recorded and would have been recoverable from future revenue. These changes will be applied retrospectively without restatement beginning January 1, 2009.

Intangible Assets

The CICA Handbook implemented revisions to standards dealing with intangible assets effective for fiscal years beginning on or after October 1, 2008. The revisions are intended to align the definition of an intangible asset in Canadian GAAP with that in International Financial Reporting Standards (IFRS) and U.S. GAAP. CICA Handbook Section 1000 "Financial Statement Concepts" was revised to remove material that permitted the recognition of assets that might not otherwise meet the definition of an asset and to add guidance from the International Accounting Standards Board's (IASB) "Framework for the Preparation and Presentation of Financial Statements" that helps distinguish assets from expenses. CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced CICA Handbook Section 3062 "Goodwill and Other Intangible Assets", gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. In addition, CICA Handbook Section 3450 "Research and Development Costs" will be withdrawn from the Handbook. The Company does not expect these changes to have a material effect on its financial statements.

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

CICA Handbook Section 1582 "Business Combinations" is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". These standards will require a change in the measurement of non-controlling interest and will require the change to be presented as part of shareholders' equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling interest and non-controlling interest. These standards will be effective January 1, 2011, with early adoption permitted. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards

The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt IFRS, as issued by the IASB, effective January 1, 2011. In June 2008, the Canadian Securities Administrators proposed that Canadian public companies that are SEC registrants, such as TransCanada, retain the option to prepare their financial statements under U.S. GAAP instead of IFRS. In November 2008, the SEC issued for public comment a recommendation that, beginning in 2014, U.S. issuers be required to adopt IFRS using a phased-in approach based on market capitalization.

TransCanada is currently considering the impact a conversion to IFRS or U.S. GAAP would have on its accounting systems and financial statements. TransCanada's conversion project planning includes an analysis of project structure and governance, resources and training, analysis of key GAAP differences and a phased approach to the assessment of current accounting policies and implementation. The current status of the key elements of TransCanada's conversion project is as follows:

Project Structure and Governance
A Steering Committee and an Implementation Committee have been established to provide directional leadership for the conversion project and to assist in developing accounting policy recommendations. These are multi-disciplinary committees and include representatives from Accounting, Information Technology, Treasury, Investor Relations, Human Resources and Operations. Management updates the Audit Committee at least quarterly on the status of the project.

Resources and Training
TransCanada's conversion project team has been assembled and will support the conversion effort through project leadership, training, issue identification, technical research, policy recommendations, work group leadership and implementation support.

TransCanada's IFRS training plan was developed and introduced in 2008. The first stage of the training has been completed and included IFRS project awareness sessions and a comprehensive IFRS immersion course. Later phases of the project will include more directed technical and implementation training relating to new accounting policies, procedures and processes. Throughout the project, IFRS training will be offered on a regular basis to ensure that TransCanada staff remains current with respect to new IFRS developments.

Analysis of Significant GAAP Differences
The project team is currently assessing the differences between Canadian GAAP and IFRS. TransCanada's conversion project is being executed using a risk-based methodology focusing on the significant differences between Canadian GAAP and IFRS. A high-level diagnostic was completed in 2008 outlining the significant differences and rating each option based on its significance to TransCanada. In making this assessment, the technical accounting complexity, availability of policy choices, estimated need for conversion resources and impact on systems were considered. The differences between Canadian and US GAAP have already been identified in the Company's U.S. GAAP reconciliation. The most significant differences under the IFRS and U.S. GAAP conversion options were identified as follows:

IFRS
Converting to IFRS would have a significant impact on TransCanada's rate-regulated operations, property plant and equipment, employee benefits, income taxes, financial statement disclosure and the initial adoption of IFRS in accordance with IFRS 1 "First-Time Adoption of IFRS".

Project work groups are currently conducting a detailed analysis of the significant differences identified to date and assessing the impact they could have on TransCanada's financial reporting, information systems and internal controls over financial reporting. Less significant differences will be assessed starting in 2009. Under existing Canadian GAAP, TransCanada follows specific accounting policies unique to rate-regulated businesses. TransCanada is actively monitoring ongoing discussions and developments at the IASB regarding potential future guidance to clarify the applicability of certain aspects of rate-regulated accounting under IFRS. The IASB is expected to issue a proposed standard for rate-regulated businesses in 2009.

Several IFRS standards are in the process of being amended by the IASB. Amendments to existing standards are expected to continue until the transition date of January 1, 2011. TransCanada actively monitors the IASB's schedule of projects, giving consideration to any proposed changes, where applicable, in its assessment of differences between IFRS and Canadian GAAP.

At the current stage of the project, TransCanada cannot reasonably determine the full impact that adopting IFRS would have on its financial position and future results. In addition, developments with respect to specific rate-regulated accounting guidance under IFRS could have a significant effect on the scope of the project and on TransCanada's financial results.

U.S. GAAP
As an SEC registrant, TransCanada is currently required to prepare and file a reconciliation from Canadian GAAP to U.S. GAAP. The differences that have the most significant impact on TransCanada, as outlined in the reconciliation, include valuation of proprietary natural gas inventory held in storage, measurement of the deficit or surplus of defined benefit pension plans and recognition of deferred tax liabilities for TransCanada's rate-regulated business. As previously noted, effective January 1, 2009, the U.S. GAAP difference with respect to recognition of deferred tax liabilities for TransCanada's rate-regulated businesses will be eliminated.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[1]

	2008			
(unaudited) *(millions of dollars except per share amounts)*	**Fourth**	**Third**	**Second**	**First**
Revenues	**2,332**	**2,137**	**2,017**	**2,133**
Net Income	**277**	**390**	**324**	**449**
Share Statistics				
Net income per share – Basic	**$0.47**	**$0.67**	**$0.58**	**$0.83**
Net income per share – Diluted	**$0.46**	**$0.67**	**$0.58**	**$0.83**
Dividend declared per common share	**$0.36**	**$0.36**	**$0.36**	**$0.36**

	2007			
(unaudited) *(millions of dollars except per share amounts)*	Fourth	Third	Second	First
Revenues	2,189	2,187	2,208	2,244
Net Income	377	324	257	265
Share Statistics				
Net income per share – Basic	$0.70	$0.60	$0.48	$0.52
Net income per share – Diluted	$0.70	$0.60	$0.48	$0.52
Dividend declared per common share	$0.34	$0.34	$0.34	$0.34

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP.

Factors Impacting Quarterly Financial Information
In Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net earnings fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net earnings during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and net earnings are affected by seasonal weather conditions, customer demand, market prices, planned and unplanned plant outages, acquisitions and divestitures, and developments outside of the normal course of operations.

Significant developments that affected quarterly net earnings in 2008 and 2007 were as follows:

- ***Fourth quarter 2008***, Energy's net earnings included net unrealized gains of $6 million after tax ($7 million pre-tax) due to changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Corporate's net expenses included net unrealized losses of $39 million after tax ($57 million pre-tax) for changes in the fair value of derivatives, which are used to manage the Company's exposure to rising interest rates but do not qualify as hedges for accounting purposes.
- ***Third quarter 2008***, Energy's net earnings included contributions from the August 26, 2008 acquisition of Ravenswood. Corporate's net earnings included favourable income tax adjustments of $26 million from an internal restructuring and realization of losses.
- ***Second quarter 2008***, Energy's net earnings included net unrealized gains of $8 million after tax ($12 million pre-tax) due to changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. In addition, Western Power's revenues and operating income increased due to higher overall realized prices and market heat rates in Alberta.
- ***First quarter 2008***, Pipelines' net earnings included $152 million after tax ($240 million pre-tax) from the Calpine bankruptcy settlements received by GTN and Portland, and proceeds of $10 million after tax ($17 million pre-tax) from a lawsuit settlement. Energy's net earnings included a writedown of $27 million after tax ($41 million pre-tax) of costs related to Broadwater and net unrealized losses of $12 million after tax ($17 million pre-tax) due to changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts.
- ***Fourth quarter 2007***, net earnings included $56 million ($30 million in Energy and $26 million in Corporate) of favourable income tax adjustments resulting from reductions in Canadian federal income tax rates and other legislative changes, and a $14 million ($16 million pre-tax) gain on sale of land previously held for development. Pipelines' net earnings increased as a result of recording incremental earnings related to the rate case settlement reached for the GTN System, effective January 1, 2007. Energy's net earnings included net unrealized gains of $10 million after tax ($15 million pre-tax) due to changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts.
- ***Third quarter 2007***, net earnings included $15 million of favourable income tax reassessments and associated interest income relating to prior years.
- ***Second quarter 2007***, net earnings included $16 million ($4 million in Energy and $12 million in Corporate) related to positive income tax adjustments resulting from reductions in Canadian federal income tax rates. Pipeline's net earnings increased as a result of a settlement reached on the Canadian Mainline, which was approved by the NEB in May 2007.
- ***First quarter 2007***, net earnings included $15 million related to positive income tax adjustments. In addition, Pipelines' net earnings included contributions from the February 22, 2007, acquisition of ANR and additional ownership interests in Great Lakes. Energy's net earnings included earnings from the Edson natural gas facility, which was placed in service on December 31, 2006.

FOURTH QUARTER 2008 HIGHLIGHTS

CONSOLIDATED RESULTS OF OPERATIONS
Reconciliation of Comparable Earnings to Net Income

(unaudited) *(millions of dollars except per share amounts)*	**2008**	2007
Pipelines	**210**	202
Energy		
Comparable earnings[1]	**147**	104
Specific items (net of tax, where applicable):		
Fair value adjustments of natural gas storage inventory and forward contracts	**6**	10
Gain on sale of land	**–**	14
Income tax adjustments	**–**	30
Net income	**153**	158
Corporate		
Comparable expenses[1]	**(86)**	(9)
Specific item:		
Income tax reassessments and adjustments	**–**	26
Net (expenses)/income	**(86)**	17
Net Income	**277**	377
Net Income Per Share		
Basic	**$0.47**	$0.70
Diluted	**$0.46**	$0.70
Comparable Earnings[1]	**271**	297
Specific items (net of tax, where applicable):		
Fair value adjustments of natural gas storage inventory and forward contracts	**6**	10
Gain on sale of land	**–**	14
Income tax reassessments and adjustments	**–**	56
Net Income	**277**	377
Comparable Earnings Per Share[1]	**$0.46**	$0.55
Specific items – per share:		
Fair value adjustments of natural gas storage inventory and forward contracts	**0.01**	0.02
Gain on sale of land	**–**	0.03
Income tax reassessments and adjustments	**–**	0.10
Net Income Per Share	**$0.47**	$0.70

(1) Refer to the "Non-GAAP Measures" section of this MD&A for further discussion of comparable earnings and comparable earnings per share.

TransCanada's net income in fourth quarter 2008 was $277 million or $0.47 per share compared to $377 million or $0.70 per share in fourth quarter 2007. Net income decreased primarily due to increased net expenses from Corporate, which included unrealized losses of $39 million after tax or $0.07 per share in fourth quarter 2008, for changes in the fair value of derivatives, which are used to manage the Company's exposure to rising interest rates but do not qualify as hedges for accounting purposes. Corporate's net expenses also increased in fourth quarter 2008 compared to fourth quarter 2007 as a result of higher charges for financing the Company's 2008 capital program, including the Ravenswood acquisition, and higher unrealized gains in 2007 for changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations. Earnings from the Pipelines business increased in fourth quarter 2008 compared to fourth quarter 2007 primarily due to earnings recognized from a 2008 revenue requirement settlement for the Alberta System and increased earnings for PipeLines LP, partially offset by the inclusion in earnings in fourth quarter 2007 for a rate case settlement for GTN. Earnings from the Energy business were slightly lower in fourth quarter 2008 compared to fourth quarter 2007 as increases in Western Power, Eastern Power and Bruce Power were more than offset by a decrease in earnings from Natural Gas Storage in 2008 and favourable income tax adjustments that were included in fourth quarter 2007. Western Power earnings increased significantly in fourth quarter 2008 compared to fourth quarter 2007 primarily due to increased margins from the Alberta power portfolio. Energy's earnings in fourth quarter 2008 and 2007 included $6 million after tax ($7 million pre-tax) and $10 million after tax ($15 million pre-tax), respectively, of net unrealized gains resulting from changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Energy's earnings in fourth quarter 2007 also included a $14 million after-tax ($16 million pre-tax) gain on the sale of land. Net income for fourth quarter 2007 included $56 million ($30 million in Energy and $26 million in Corporate) of favourable income tax adjustments as a result of changes in Canadian federal income tax legislation. On a per share basis, the $0.23 decrease in earnings in fourth quarter 2008 compared to fourth quarter 2007 was also due to an increased number of shares outstanding following the Company's share issuances in 2008.

Comparable earnings in fourth quarter 2008 were $271 million or $0.46 per share compared to $297 million or $0.55 per share for the same period in 2007. Comparable earnings in fourth quarter 2008 and 2007 excluded the $6 million and $10 million, respectively, of net unrealized gains resulting from changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Comparable earnings in fourth quarter 2007 also excluded the $56 million of favourable income tax adjustments and $14 million gain on the sale of land.

The Pipelines business generated net income and comparable earnings of $210 million in fourth quarter 2008, an increase of $8 million compared to net income and comparable earnings of $202 million in fourth quarter 2007.

Canadian Mainline's net income for fourth quarter 2008 increased $2 million, compared to the same period in 2007 primarily due to higher performance-based incentives earned, increased OM&A cost savings and a higher ROE, as determined by the NEB, of 8.71 per cent in 2008 compared to 8.46 per cent in 2007. These increases were partially offset by a lower average investment base.

The Alberta System's net income in fourth quarter 2008 was $48 million compared to $41 million in fourth quarter 2007. Earnings increased primarily due to the recognition of earnings related to the revenue requirement settlement in fourth quarter 2008. Earnings in 2007 reflected an approved ROE of 8.51 per cent on a deemed common equity of 35 per cent.

ANR's net income in fourth quarter 2008 was $38 million compared to $35 million in fourth quarter 2007. The increase in fourth quarter 2008 was primarily due to higher revenues from new growth projects and the positive impact of a stronger U.S. dollar. These increases were partially offset by higher OM&A costs, including Hurricane Ike remediation costs.

GTN's comparable earnings in fourth quarter 2008 decreased $16 million compared to the same period in 2007. The decrease was primarily due to the positive impact of the rate case settlement included in fourth quarter 2007, partially offset by decreased OM&A expenses.

TransCanada's proportionate share of net income from Other Pipelines was $29 million for the three months ended December 31, 2008 compared to $16 million for the same period in 2007. Other Pipelines' earnings increased in fourth quarter 2008 primarily due to lower support costs, higher PipeLines LP and Tamazunchale earnings, and a stronger U.S. dollar, partially offset by lower TransGas, Gas Pacifico/ INNERGY and Portland earnings.

Energy's net income of $153 million in fourth quarter 2008 decreased $5 million compared to $158 million in fourth quarter 2007. Comparable earnings in fourth quarter 2008 of $147 million increased $43 million compared to $104 million for the same period in 2007. Comparable earnings excluded the net unrealized gains of $6 million after tax and $10 million after tax in fourth quarter 2008 and 2007, respectively, resulting from changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. In addition, comparable earnings in fourth quarter 2007 excluded the $14 million gain on sale of land and $30 million of favourable income tax adjustments.

Western Power's operating income of $106 million in fourth quarter 2008 increased $48 million compared to $58 million in fourth quarter 2007 primarily due to increased margins from the Alberta power portfolio, which resulted from higher overall realized power prices and market heat rates on both contracted and uncontracted volumes of power sold in Alberta. The market heat rate is determined by dividing the average price of power per MWh by the average price of natural gas per GJ for a given period.

Eastern Power's operating income of $73 million in fourth quarter 2008 increased $7 million compared to $66 million in fourth quarter 2007. The increase was due to higher realized prices on sales to commercial and industrial customers in New England, the positive impact of the stronger U.S. dollar in fourth quarter 2008 and incremental earnings from the Carleton wind farm, which went into service in November 2008. On December 31, 2008, Ravenswood fulfilled its obligation under a tolling agreement with Hess Corporation that was in place at the time of acquisition. In 2009, TransCanada's marketing operation will manage marketing of the Ravenswood plant output in a manner consistent with its other U.S. Northeast portfolio of assets.

TransCanada's combined operating income of $50 million from its investment in Bruce Power increased $7 million in fourth quarter 2008 compared to fourth quarter 2007 primarily due to higher revenues resulting from higher realized prices. TransCanada's proportionate share of operating loss in Bruce A increased $1 million to $6 million in fourth quarter 2008 compared to fourth quarter 2007 as a result of lower revenues due to decreased output, partially offset by higher contract prices and lower operating costs. TransCanada's proportionate share of operating income in Bruce B increased $8 million to $61 million in fourth quarter 2008 compared to fourth quarter 2007 primarily due to higher realized prices achieved during fourth quarter 2008, as well as increased output. The increase in realized prices was due to higher contract prices on a larger proportion of volumes sold under contract in the three months ended December 31, 2008 compared to the same period in 2007.

Natural Gas Storage operating income of $40 million in fourth quarter 2008 decreased $17 million compared to $57 million in fourth quarter 2007. The decrease was due to lower realized seasonal natural gas price spreads at the Edson facility compared to the same period in 2007. Operating income in fourth quarter 2008 included net unrealized gains of $7 million for changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts compared to net unrealized gains of $15 million for the same period in 2007.

Corporate's net expenses for the three months ended December 31, 2008 were $86 million compared to net income of $17 million for the same period in 2007. Excluding the $26 million of favourable income tax adjustments in fourth quarter 2007, Corporate's comparable expenses increased $77 million in fourth quarter 2008 compared to fourth quarter 2007. The increase in comparable expenses in fourth quarter 2008 was primarily due to net unrealized losses of $39 million after tax from changes in the fair value of derivatives, which are used to manage the Company's exposure to rising interest rate rates but do not qualify as hedges for accounting purposes. In addition, higher financial charges resulting from financing the Ravenswood acquisition and higher losses from the change in fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations were partially offset by increased capitalization of interest to finance a larger capital spending program.

SHARE INFORMATION

At February 23, 2009, TransCanada had 619 million issued and outstanding common shares. In addition, there were 8 million outstanding options to purchase common shares, of which 7 million were exercisable as at February 23, 2009.

OTHER INFORMATION

Additional information relating to TransCanada, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada Corporation.

Other selected consolidated financial information for 2000 to 2008 is found under the heading "Nine Year Financial Highlights" in the Supplementary Information section of the Company's Annual Report.

GLOSSARY OF TERMS

AFUDC	Allowance for funds used during construction
AGIA	Alaska Gasline Inducement Act
Alaska Pipeline Project	A proposed natural gas pipeline extending from a new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta
Alberta System	A natural gas transmission system in Alberta
American Natural Resources (ANR)	A natural gas transmission system extending from producing fields located primarily in Oklahoma, Texas, Louisiana and the Gulf of Mexico to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and regulated underground natural gas storage facilities in Michigan
ANR Pipeline	ANR Pipeline Company
APG	Aboriginal Pipeline Group
AUC	Alberta Utilities Commission
B.C.	British Columbia
Bbl/d	Barrels per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Bear Creek	A natural gas-fired cogeneration plant near Grande Prairie, Alberta
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	A proposed pipeline from the Powder River Basin in Wyoming to the Northern Border system in North Dakota
BPC	BPC Generation Infrastructure Trust
Broadwater	A proposed offshore LNG project located in the New York waters of Long Island Sound
Bruce A	A partnership interest in the nuclear power generation facilities of Bruce Power A L.P.
Bruce B	A partnership interest in the nuclear power generation facilities of Bruce Power L.P
Bruce Power	Bruce A and Bruce B, collectively
Calpine	Calpine Corporation
Cameco	Cameco Corporation
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Cancarb	A waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta
CAPLA	Canadian Alliance of Pipeline Landowners' Associations
Carseland	A natural gas-fired cogeneration plant located near Carseland, Alberta
Cartier Wind	Six wind farms in Gaspé, Québec, three of which have been built
Chinook	A proposed HVDC transmission project that will originate in Montana and terminate in Nevada
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station under development in Coolidge, Arizona
CrossAlta	An underground natural gas storage facility near Crossfield, Alberta
DRP	Dividend Reinvestment and Share Purchase Plan
Edson	A natural gas storage facility near Edson, Alberta
FAS	Financial Accounting Standard
FCM	Forward Capacity Market
FERC	U.S. Federal Energy Regulatory Commission
Foothills	A natural gas transmission system extending from central Alberta to the B.C./U.S. border and to the Saskatchewan/U.S. border
Framework	Regulatory Framework for Air Emissions
GAAP	Generally accepted accounting principles
Gas Pacifico	A natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile
GHG	Greenhouse gas
GJ	Gigajoule
Grandview	A natural gas-fired cogeneration plant near Saint John, New Brunswick
Great Lakes	A natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S.
Gas Transmission Network (GTN)	GTN System and North Baja, collectively
GTNC	Gas Transmission Northwest Corporation
GTN System	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
GWh	Gigawatt hours
Halton Hills	A natural gas-fired, combined-cycle power plant near Toronto, Ontario
HS&E	Health, Safety and Environment
HVDC	High voltage direct current

IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
INNERGY	An industrial natural gas marketing company based in Concepción, Chile
Iroquois	A natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to the northeastern U.S.
ISO	International Organization of Standardization
ISO-NE	Independent System Operator New England
Keystone	A pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma
Keystone partnerships	TransCanada Keystone Pipeline Limited Partnership and TransCanada Keystone Pipeline, LP, collectively
Kibby Wind	A wind power project located in Kibby and Skinner Townships in northwestern Franklin County, Maine
km	Kilometres
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
MacKay River	A natural gas-fired cogeneration plant located near Fort McMurray, Alberta
MD&A	Management's Discussion and Analysis
Mackenzie Gas Pipeline (MGP)	A proposed natural gas pipeline to be constructed from a point near Inuvik, Northwest Territories to the northern border of Alberta
Mirant	Mirant Corporation and certain of its subsidiaries
mmcf/d	Million cubic feet per day
Moody's	Moody's Investors Service
MW	Megawatt
MWh	Megawatt hours
NEB	National Energy Board of Canada
Net earnings	Net income from continuing operations
North Baja	A natural gas transmission system extending from Arizona to the Baja California, Mexico/California border
Northern Border	A natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest
NorthernLights	A proposed HVDC electric transmission line running from central Alberta to a terminal in southern Alberta and interconnecting with the Pacific Northwest
NYISO	New York Independent System Operator
OM&A	Operating, maintenance and administration
OPA	Ontario Power Authority
Ocean State Power (OSP)	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
Palomar	A proposed pipeline extending from the GTN System to the Columbia River northwest of Portland
Pathfinder	A proposed pipeline from Meeker, Colorado to the Northern Border system in North Dakota
PipeLines LP	TC PipeLines, LP
PNGTS	Portland Natural Gas Transmission System
Portland	A natural gas transmission system that extends from a point near East Hereford, Québec to the northeastern U.S.
Portlands Energy	A combined-cycle natural gas cogeneration plant near downtown Toronto, Ontario
PPA	Power purchase arrangement
Ravenswood	A natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined cycle and combustion turbine technology located in Queens, New York
Redwater	A natural gas-fired cogeneration plant located near Redwater, Alberta
RGGI	Regional Greenhouse Gas Initiative
ROE	Rate of return on common equity
Salt River Project	Salt River Project Agricultural Improvement and Power District
SEC	U.S. Securities and Exchange Commission
Sempra	Sempra Pipelines and Storage
Sheerness	A coal-fired power generating facility located near Hanna, Alberta
STEP 2008	Storage enhancement project
Sundance A	A coal-fired power generating facility located near Wabamun, Alberta
Sundance B	A coal-fired power generating facility located near Wabamun, Alberta
Sunstone	A proposed pipeline from Wyoming to Stanfield, Oregon

Tamazunchale	A natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi
TC Hydro	Hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts
TCPL	TransCanada PipeLines Limited
TCPM	TransCanada Power Marketing Ltd.
Trans Québec & Maritimes (TQM)	A natural gas transmission system that connects with the Canadian Mainline and transports natural gas in Québec, from Montreal to the Portland system and to Québec City
TransCanada or the Company	TransCanada Corporation
TransGas	A natural gas transmission system, extending from Mariquita in the central region of Colombia to Cali in the southwest region of Colombia
Tuscarora	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S.	United States
VaR	Value-at-Risk methodology
Ventures LP	Natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta
WCI	Western Climate Initiative
WCSB	Western Canada Sedimentary Basin
Williams	Williams Gas Pipeline Company, LLC
Zephyr	A proposed HVDC transmission project that will originate in Wyoming and terminate in Nevada

Report of Management

The consolidated financial statements included in this Annual Report are the responsibility of TransCanada Corporation's (TransCanada or the Company) management and have been approved by the Board of Directors of the Company. These consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles (GAAP) in Canada and include amounts that are based on estimates and judgements. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management's Discussion and Analysis in this Annual Report has been prepared by management based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial and operating performance in 2008 to that in 2007 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, it highlights significant changes between 2007 and 2006.

Management has designed and maintains a system of internal accounting controls, including a program of internal audits. Management believes that these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal accounting control process includes management's communication to employees of policies that govern ethical business conduct.

Under the supervision of, and with the participation of, the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. TransCanada acquired the Ravenswood Generating Station (Ravenswood) in 2008 and began consolidating the operations of Ravenswood from the date of acquisition. Management has excluded this business from its evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2008. The net income attributable to this business represented less than one per cent of the Company's consolidated net income for the year ended December 31, 2008 and its aggregate total assets represented approximately nine per cent of the Company's consolidated total assets as at December 31, 2008.

Based on their evaluation, management concluded that internal control over financial reporting is effective as of December 31, 2008 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors has appointed an Audit Committee consisting of independent, non-management directors. The Audit Committee meets with management at least six times a year and meets independently with the internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee reviews the Annual Report, including the consolidated financial statements, before the consolidated financial statements are submitted to the Board of Directors for approval. The internal and independent external auditors are able to access the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with Canadian GAAP. The report of KPMG LLP outlines the scope of its examination and its opinion on the consolidated financial statements.

Harold N. Kvisle
President and
Chief Executive Officer

Gregory A. Lohnes
Executive Vice-President and
Chief Financial Officer

February 23, 2009

Auditors' Report

To the Shareholders of TransCanada Corporation

We have audited the consolidated balance sheets of TransCanada Corporation as at December 31, 2008 and 2007 and the consolidated statements of income, comprehensive income, accumulated other comprehensive income, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 23, 2009

TRANSCANADA CORPORATION

CONSOLIDATED INCOME

Year ended December 31 *(millions of dollars except per share amounts)*	**2008**	2007	2006
Revenues	**8,619**	8,828	7,520
Operating Expenses			
Plant operating costs and other	**3,062**	3,030	2,411
Commodity purchases resold	**1,511**	1,959	1,707
Depreciation	**1,189**	1,179	1,059
	5,762	6,168	5,177
	2,857	2,660	2,343
Other Expenses/(Income)			
Financial charges (Note 10)	**943**	943	825
Financial charges of joint ventures (Note 11)	**72**	75	92
Interest income and other	**(92)**	(168)	(179)
Calpine bankruptcy settlements (Note 17)	**(279)**	–	–
Writedown of Broadwater LNG project costs (Note 7)	**41**	–	–
	685	850	738
Income from Continuing Operations before Income Taxes and Non- Controlling Interests	**2,172**	1,810	1,605
Income Taxes (Note 18)			
Current	**526**	432	301
Future	**76**	58	175
	602	490	476
Non-Controlling Interests (Note 15)	**130**	97	78
Net Income from Continuing Operations	**1,440**	1,223	1,051
Net Income from Discontinued Operations (Note 24)	**–**	–	28
Net Income	**1,440**	1,223	1,079
Net Income per Share (Note 16)			
Basic			
Continuing operations	**$2.53**	$2.31	$2.15
Discontinued operations	**–**	–	0.06
	$2.53	$2.31	$2.21
Diluted			
Continuing operations	**$2.52**	$2.30	$2.14
Discontinued operations	**–**	–	0.06
	$2.52	$2.30	$2.20

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED CASH FLOWS

Year ended December 31 *(millions of dollars)*	**2008**	2007	2006
Cash Generated from Operations			
Net income	**1,440**	1,223	1,079
Depreciation	**1,189**	1,179	1,059
Future income taxes (Note 18)	**76**	58	175
Non-controlling interests (Note 15)	**130**	97	78
Employee future benefits funding lower than/(in excess of) expense (Note 21)	**17**	43	(31)
Writedown of Broadwater LNG project costs (Note 7)	**41**	–	–
Other	**128**	21	18
	3,021	2,621	2,378
(Increase)/decrease in operating working capital (Note 22)	**(181)**	215	(303)
Net cash provided by operations	**2,840**	2,836	2,075
Investing Activities			
Capital expenditures	**(3,134)**	(1,651)	(1,572)
Acquisitions, net of cash acquired (Note 9)	**(3,229)**	(4,223)	(470)
Disposition of assets, net of current income taxes (Note 9)	**28**	35	23
Deferred amounts and other	**(168)**	(340)	(97)
Net cash used in investing activities	**(6,503)**	(6,179)	(2,116)
Financing Activities			
Dividends on common shares (Note 16)	**(577)**	(546)	(617)
Distributions paid to non-controlling interests	**(141)**	(88)	(72)
Notes payable issued/(repaid), net (Note 19)	**1,293**	(46)	(495)
Long-term debt issued, net of issue costs (Note 10)	**2,197**	2,616	2,107
Reduction of long-term debt	**(840)**	(1,088)	(729)
Long-term debt of joint ventures issued (Note 11)	**173**	142	56
Reduction of long-term debt of joint ventures	**(120)**	(157)	(70)
Common shares issued, net of issue costs (Note 16)	**2,384**	1,711	39
Junior subordinated notes issued, net of issue costs (Note 12)	**–**	1,094	–
Preferred securities redeemed	**–**	(488)	–
Partnership units of subsidiary issued (Note 9)	**–**	348	–
Net cash provided by financing activities	**4,369**	3,498	219
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**98**	(50)	9
Increase in Cash and Cash Equivalents	**804**	105	187
Cash and Cash Equivalents			
Beginning of year	**504**	399	212
Cash and Cash Equivalents			
End of year	**1,308**	504	399

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION

CONSOLIDATED BALANCE SHEET

December 31 *(millions of dollars)*	**2008**	2007
ASSETS		
Current Assets		
Cash and cash equivalents	**1,308**	504
Accounts receivable	**1,280**	1,116
Inventories	**489**	497
Other	**523**	188
	3,600	2,305
Plant, Property and Equipment (Note 5)	**29,189**	23,452
Goodwill (Note 6)	**4,397**	2,633
Other Assets (Note 7)	**2,228**	1,940
	39,414	30,330
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 19)	**1,702**	421
Accounts payable	**1,876**	1,767
Accrued interest	**359**	261
Current portion of long-term debt (Note 10)	**786**	556
Current portion of long-term debt of joint ventures (Note 11)	**207**	30
	4,930	3,035
Deferred Amounts (Note 13)	**1,719**	1,107
Future Income Taxes (Note 18)	**1,223**	1,179
Long-Term Debt (Note 10)	**15,368**	12,377
Long-Term Debt of Joint Ventures (Note 11)	**869**	873
Junior Subordinated Notes (Note 12)	**1,213**	975
	25,322	19,546
Non-Controlling Interests (Note 15)	**1,194**	999
Shareholders' Equity	**12,898**	9,785
	39,414	30,330

Commitments, Contingencies and Guarantees (Note 23)

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

Harold N. Kvisle
Director

Kevin E. Benson
Director

TRANSCANADA CORPORATION
CONSOLIDATED COMPREHENSIVE INCOME

Year ended December 31 *(millions of dollars)*	**2008**	2007	2006
Net Income	**1,440**	1,223	1,079
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**571**	(350)	6
Change in gains and losses on hedges of investments in foreign operations[2]	**(589)**	79	(6)
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	**(60)**	42	–
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	**(23)**	42	–
Change in gains and losses on available-for-sale financial instruments[5]	**2**	–	–
Other Comprehensive Income/(Loss)	**(99)**	(187)	–
Comprehensive Income	**1,341**	1,036	1,079

(1) Net of income tax recovery of $104 million in 2008 (2007 – $101 million expense; 2006 – $3 million expense).

(2) Net of income tax recovery of $303 million in 2008 (2007 – $41 million expense; 2006 – $3 million recovery).

(3) Net of income tax recovery of $41 million in 2008 (2007 – $27 million expense).

(4) Net of income tax recovery of $19 million in 2008 (2007 – $23 million expense).

(5) Net of income tax expense of nil in 2008.

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION

CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE INCOME

(millions of dollars)	Currency Translation Adjustment	Cash Flow Hedges and Other	Total
Balance at December 31, 2005	(90)	–	(90)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	6	–	6
Change in gains and losses on hedges of investments in foreign operations[2]	(6)	–	(6)
Balance at December 31, 2006	(90)	–	(90)
Transition adjustment resulting from adopting new financial instruments standards[3]	–	(96)	(96)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(350)	–	(350)
Change in gains and losses on hedges of investments in foreign operations[2]	79	–	79
Change in gains and losses on derivative instruments designated as cash flow hedges[4]	–	42	42
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[5][6]	–	42	42
Balance at December 31, 2007	(361)	(12)	(373)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**571**	–	**571**
Change in gains and losses on hedges of investments in foreign operations[2]	**(589)**	–	**(589)**
Change in gains and losses on derivative instruments designated as cash flow hedges[4]	–	**(60)**	**(60)**
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[5][6]	–	**(23)**	**(23)**
Change in gains and losses on available-for-sale financial instruments[7]	–	**2**	**2**
Balance at December 31, 2008	**(379)**	**(93)**	**(472)**

(1) Net of income tax recovery of $104 million in 2008 (2007 – $101 million expense; 2006 – $3 million expense).

(2) Net of income tax recovery of $303 million in 2008 (2007 – $41 million expense; 2006 – $3 million recovery).

(3) Net of income tax recovery of $44 million in 2007.

(4) Net of income tax recovery of $41 million in 2008 (2007 – $27 million expense).

(5) Net of income tax recovery of $19 million in 2008 (2007 – $23 million expense).

(6) The amount of losses related to cash flow hedges reported in accumulated other comprehensive income that will be reclassified to net income in 2009 is estimated to be $62 million ($41 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

(7) Net of income tax expense of nil in 2008.

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION

CONSOLIDATED SHAREHOLDERS' EQUITY

Year ended December 31 *(millions of dollars)*	**2008**	2007	2006
Common Shares			
Balance at beginning of year	**6,662**	4,794	4,755
Proceeds from shares issued under public offering, net of issue costs (Note 16)	**2,363**	1,683	–
Shares issued under dividend reinvestment plan (Note 16)	**218**	157	–
Proceeds from shares issued on exercise of stock options (Note 16)	**21**	28	39
Balance at end of year	**9,264**	6,662	4,794
Contributed Surplus			
Balance at beginning of year	**276**	273	272
Issuance of stock options (Note 16)	**3**	3	1
Balance at end of year	**279**	276	273
Retained Earnings			
Balance at beginning of year	**3,220**	2,724	2,269
Net income	**1,440**	1,223	1,079
Common share dividends	**(833)**	(731)	(624)
Transition adjustment resulting from adopting new financial instruments accounting standards	**–**	4	–
Balance at end of year	**3,827**	3,220	2,724
Accumulated Other Comprehensive Income, Net of Income Taxes			
Balance at beginning of year	**(373)**	(90)	(90)
Other comprehensive income/(loss)	**(99)**	(187)	–
Transition adjustment resulting from adopting new financial instruments accounting standards	**–**	(96)	–
Balance at end of year	**(472)**	(373)	(90)
	3,355	2,847	2,634
Total Shareholders' Equity	**12,898**	9,785	7,701

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada or the Company) is a leading North American energy company. TransCanada operates in two business segments, Pipelines and Energy, each of which offers different products and services.

Pipelines
The Pipelines segment consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities. Through its Pipelines segment, TransCanada owns and operates:

- a natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta (Alberta System);
- a natural gas transmission system extending from producing fields located primarily in Oklahoma, Texas, Louisiana and the Gulf of Mexico to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and to regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from the British Columbia (B.C.)/Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon (GTN System);
- a natural gas transmission system extending from central Alberta to the B.C./United States border and to the Saskatchewan/U.S. border (Foothills);
- a natural gas transmission system extending from Arizona to the Baja California, Mexico/California border (North Baja);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP);
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale);
- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S. (Great Lakes);
- a 50 per cent interest in a natural gas transmission system that connects with the Canadian Mainline and transports natural gas in Québec, from Montreal to the Portland system and to Québec City (TQM); and
- a 61.7 per cent interest in a natural gas transmission system that extends from a point near East Hereford, Québec to the northeastern U.S. (Portland).
- a 32.1 per cent interest in TC PipeLines, LP (PipeLines LP), which owns the following pipelines operated by TransCanada:
  - a 46.4 per cent interest in Great Lakes, in which TransCanada has a combined 68.5 per cent effective ownership interest through PipeLines LP and a direct interest described above;
  - a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TransCanada has a 16.1 per cent effective ownership interest through PipeLines LP; and
  - 100 per cent of a natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada (Tuscarora), in which TransCanada has a 32.1 per cent effective ownership interest through PipeLines LP.

TransCanada owns but does not operate:

- a 44.5 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S. (Iroquois);
- a 46.5 per cent interest in a natural gas transmission system, extending from Mariquita in the central region of Colombia to Cali in the southwest region of Colombia (TransGas); and
- a 30 per cent interest in a natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile (Gas Pacifico), and in an industrial natural gas marketing company based in Concepción (INNERGY).

TransCanada has a 62 per cent interest in a pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and at Cushing, Oklahoma (Keystone).

Energy

The Energy segment consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company also sells electricity and holds interests in liquefied natural gas (LNG) regasification projects in North America. Through its Energy segment, TransCanada owns and operates:

- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);
- a natural gas and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);
- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview); and
- a natural gas storage facility near Edson, Alberta (Edson).

TransCanada owns but does not operate:

- a 48.9 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce Power A L.P. (Bruce A) and Bruce Power L.P. (Bruce B) (collectively Bruce Power), respectively, located near Tiverton, Ontario;
- a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau and Carleton wind farms, three of six planned wind farms in Gaspé, Québec (Cartier Wind); and
- a 60 per cent interest in an underground natural gas storage facility near Crossfield, Alberta (CrossAlta).

TransCanada also has long-term power purchase arrangements (PPA) in place for:

- 100 per cent of the production of the Sundance A power facilities and, through a partnership, 50 per cent of the production of the Sundance B power facilities near Wabamun, Alberta; and
- 756 megawatts (MW) of the generating capacity from the Sheerness power facility near Hanna, Alberta.

TransCanada has interests in the following projects under construction:

- a 50 per cent interest in a natural gas-fired, combined-cycle cogeneration plant near downtown Toronto, Ontario (Portlands Energy);
- a natural gas-fired, combined-cycle power plant near Toronto (Halton Hills); and
- a wind power project located in Kibby and Skinner Townships in northwestern Franklin County, Maine (Kibby Wind).

NOTE 2 ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with Canadian GAAP. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses as the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

Basis of Presentation

The consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its 32.1 per cent ownership interest in PipeLines LP and its 61.7 per cent interest in the Portland Natural Gas Transmission System (Portland) as the Company is able to exercise control over these assets. The other partners' interests are included in Non-Controlling Interests. TransCanada proportionately consolidates its share of the accounts of joint ventures in which the Company is able to exercise joint control. TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

Regulation

The Canadian Mainline, Foothills Pipe Lines Ltd. (Foothills) and Trans Québec & Maritimes System (TQM) are subject to the authority of the National Energy Board (NEB) of Canada. The Alberta System is regulated by the Alberta Utilities Commission (AUC). The GTN System and North Baja (collectively, GTN), the ANR Pipeline Company, the ANR Storage Company and the other natural gas pipelines in the U.S. are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). These natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. The timing of recognition of certain revenues and expenses in these regulated businesses may differ from that otherwise expected under GAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. The impact of rate regulation on TransCanada is provided in Note 14 of these financial statements.

Revenue Recognition

Pipelines

In the Pipelines segment, revenues from Canadian operations subject to rate regulation are recognized in accordance with decisions made by the NEB and AUC. Revenues from U.S. operations subject to rate regulation are recorded in accordance with FERC rules and regulations. The Company's natural gas pipeline revenues are generally based on quantity of gas delivered or contracted capacity. Revenues are recognized on firm contracted capacity over the contract period. For interruptible or volumetric-based services, revenues are recorded when physical delivery is made. As the majority of the Company's natural gas pipelines are subject to rate regulation, revenues collected that are subject to rate proceedings may have to be refunded. Revenues from non-regulated operations are recorded when products have been delivered or services have been performed.

Energy

i) Power

Revenues from the Company's Power business are primarily derived from the sale of electricity from energy marketing activities and from the sale of unutilized natural gas fuel, which are recorded in the month of delivery. Revenues also include capacity payments and ancillary services earned as well as the impact of energy derivative contracts, the accounting for which is described in the Financial Instruments section of this note.

ii) Natural Gas Storage

Revenues earned from providing natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Forward contracts for the purchase or sale of natural gas, as well as proprietary natural gas inventory, are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Effective April 1, 2007, the Company adopted the accounting requirements for the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3031 "Inventories". Inventories primarily consist of materials and supplies, including spare parts, and are carried at the lower of average cost and net realizable value. The Company values its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas, less selling costs. To record inventory at fair value, TransCanada has designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. The Company records its net proprietary natural gas storage sales and purchases in Revenues. All changes in the fair value of the proprietary natural gas inventories are reflected in Inventories and Revenues.

Plant, Property and Equipment

Pipelines

Plant, property and equipment of the Pipelines segment are carried at cost. Depreciation is calculated on a straight-line basis. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to 25 per cent and metering and other plant equipment are depreciated at various rates. The cost of regulated pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt and an equity component based on the rate of return on rate base approved by regulators. This allowance is reflected as an increase in the cost of the assets on the balance sheet. Interest is capitalized during construction of non-regulated pipelines. The equity component of AFUDC is a non-cash expenditure.

When regulated pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Energy

Major power generation and natural gas storage plant, equipment and structures in the Energy segment are recorded at cost and depreciated on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to ten per cent. Nuclear power generation assets under capital lease are recorded initially at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives. Interest is capitalized on facilities under construction.

Corporate

Corporate plant, property and equipment are recorded at cost and depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three to 20 per cent.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as property, plant and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the purchase method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair values at the date of acquisition. Goodwill is not amortized and is tested for impairment annually, or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial assessment is made by comparing the fair value of the operations, which includes goodwill, to the book values of each reporting unit. If this fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

Power Purchase Arrangements

A PPA is a long-term contract for the purchase or sale of power on a predetermined basis. The initial payments for a PPA are deferred and amortized on a straight-line basis over the term of the contract, with remaining terms ranging from nine to 12 years. The PPAs under which TransCanada buys power are accounted for as operating leases. A portion of these PPAs has been subleased to third parties under similar terms and conditions. The subleases are accounted for as operating leases and TransCanada records the margin earned from the subleases as a component of Revenues.

Stock Options

TransCanada's Stock Option Plan permits options to be awarded to certain employees, including officers, to purchase common shares. The contractual life of options granted in 2003 and thereafter and options granted prior to 2003 is seven years and ten years, respectively. The Company uses the Black-Scholes model to determine fair value of the options on their grant date. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each of the three years following the award. Forfeitures of stock options result from their expiration or from the resignation, retirement or termination of the option holder. Stock options become null and void upon forfeiture. The Company records compensation expense over the three-year vesting period, assuming a

15 per cent forfeiture rate, with an offset to Contributed Surplus. This charge is reflected in the results of the Pipelines and Energy segments. Upon exercise of stock options, adjusted for stock options forfeited, amounts originally recorded against Contributed Surplus are reclassified to Common Shares.

Income Taxes

The taxes payable method of accounting for income taxes is used for tollmaking purposes for Canadian regulated natural gas transmission operations, as prescribed by regulators. It is not necessary to provide for future income taxes under the taxes payable method. As permitted by Canadian GAAP at December 31, 2008, this method is also used for accounting purposes, since there is reasonable expectation that future taxes payable will be included in future costs of service and recorded in revenues at that time. The liability method of accounting for income taxes is used for all of the Company's other operations. Under the liability method, future income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Foreign Currency Translation

The Company's foreign operations are self-sustaining and are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated at period-end exchange rates and items included in the consolidated statements of income, shareholders' equity, comprehensive income, accumulated other comprehensive income and cash flows are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in Other Comprehensive Income.

Exchange gains or losses on monetary assets and liabilities are recorded in income except for exchange gains or losses on the principal amounts of foreign currency debt related to the Alberta System, Foothills and Canadian Mainline, which are deferred until they are refunded or recovered in tolls, as permitted by regulatory bodies.

Financial Instruments

Effective January 1, 2007, the Company adopted the accounting requirements for CICA Handbook Sections 1530 "Comprehensive Income", 3855 "Financial Instruments – Recognition and Measurement", and 3865 "Hedges". Effective December 31, 2007, the Company adopted the accounting requirements for CICA Handbook Sections 3862 "Financial Instruments – Disclosure", 3863 "Financial Instruments – Presentation", and 1535 "Capital Disclosures". Adjustments to the consolidated financial statements for 2007 were made on a prospective basis.

The CICA Handbook requires that all financial instruments initially be included on the balance sheet at their fair value. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments and loans and receivables. Financial liabilities are classified as held for trading or other financial liabilities.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. A financial asset or liability may be designated as held for trading if it is entered into with the intention of generating a profit. The Company has not designated any non-derivative financial assets or liabilities as held for trading. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in Revenues. Changes in the fair value of interest rate and foreign exchange rate held-for-trading instruments are recorded in Financial Charges and in Interest Income and Other, respectively.

The available-for-sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications. TransCanada's available-for-sale financial instruments include fixed-income securities held for self-insurance. These instruments are accounted for initially at their fair value and changes to fair value are recorded through Other Comprehensive Income. Income from the settlement of available-for-sale financial assets will be included in Interest Income and Other.

The held-to-maturity classification consists of non-derivative financial assets that are accounted for at their amortized cost using the effective interest method. The Company does not have any held-to-maturity financial assets.

Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as "loans and receivables" and are measured at amortized cost using the effective interest method, net of any impairment. Loans and receivables include primarily trade accounts receivable and non-interest-bearing third-party loans receivable. Interest and other income earned from these financial assets are recorded in Interest Income and Other.

Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method. Interest expense is included in Financial Charges and in Financial Charges of Joint Ventures.

The Company uses derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices. The Company also uses a combination of derivatives and U.S. dollar-denominated debt to manage the foreign currency exposure of its foreign operations.

All derivatives are recorded on the balance sheet at fair value, with the exception of non-financial derivatives that were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements. Changes in fair value of derivatives that are not designated in a hedging relationship are recorded in Net Income. Derivatives used in hedging relationships are discussed further in the Hedges section of this note.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. Changes in the fair value of embedded derivatives that are recorded separately are included in Net Income.

The recognition of gains and losses on the derivatives for the Alberta System, Foothills and Canadian Mainline exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of rate-regulated accounting are deferred in regulatory assets or regulatory liabilities.

Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company offsets long-term debt transaction costs against the associated debt and amortizes these costs using the effective interest method for all costs except those related to the Canadian regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

The Company records the fair values of material joint and several guarantees. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to an investment account, Property, Plant and Equipment or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Hedges

The CICA Handbook specifies the criteria that must be satisfied in order to apply hedge accounting and the accounting for each of the permitted hedging strategies, including: fair value hedges, cash flow hedges and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

Documentation must be prepared at the inception of the hedging arrangement in order to qualify for hedge accounting treatment. In addition, the Company must perform an assessment of effectiveness at inception of the contract and at each reporting date.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. The changes in fair value are recognized in Net Income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest Income and Other and Financial Charges, respectively. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net Income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in Other Comprehensive Income, while any ineffective portion is recognized in Net Income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Net Income during the periods when the variability in cash flows of the hedged item affects Net Income. Gains and losses on derivatives are reclassified immediately to Net Income from Accumulated Other Comprehensive Income when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. The gains and losses arising from the changes in fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as rate-regulated assets or liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains or losses are collected from or refunded to the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in Other Comprehensive Income and the ineffective portion is recognized in Net

Income. The amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Net Income in the event the Company settles or otherwise reduces its investment in a foreign operation.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred, when a legal obligation to do so exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted at the end of each period through charges to operating expenses.

It is not possible to determine the scope and timing of asset retirements related to regulated natural gas pipelines and, therefore, it is not possible to make a reasonable estimate of the fair value of the associated liability. As a result, the Company has not recorded an amount for asset retirement obligations related to regulated natural gas pipelines, with the exception of certain abandoned facilities. Management believes it is reasonable to assume that all retirement costs associated with its regulated pipelines will be recovered through tolls in future periods.

Similarly, it is not possible to determine the scope and timing of asset retirements related to hydroelectric power plants and, therefore, it is not possible to make a reasonable estimate of the fair value of the associated liability. As a result, the Company has not recorded an amount for asset retirement obligations related to hydroelectric power plants. With respect to the nuclear assets leased by Bruce Power, the Company has not recorded an amount for asset retirement obligations, as Bruce Power leases the assets and the lessor is responsible for decommissioning liabilities under the lease agreement.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Any amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans), defined contributions plans (DC Plans), a Savings Plan and other post-employment plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed as incurred. The cost of the DB Plans and other post-employment benefits earned by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plan's assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, which are payable in cash to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, units vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Certain of the Company's joint ventures sponsor DB Plans. The Company records its proportionate share of expenses, funding contributions and accrued benefit assets and liabilities related to these plans.

NOTE 3 ACCOUNTING CHANGES

Future Accounting Changes

Rate-Regulated Operations

Effective January 1, 2009, the temporary exemption from CICA Handbook Section 1100 "Generally Accepted Accounting Principles", which permits the recognition and measurement of assets and liabilities arising from rate regulation, was withdrawn. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated entities. The Company has chosen to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's Financial Accounting Standard (FAS) 71 "Accounting for the Effects of Certain Types of Regulation". Accordingly, TransCanada will retain its current method of accounting for its rate-regulated operations, except that TransCanada will be required to recognize future income tax assets and liabilities instead of using the taxes payable method, and will record an offsetting adjustment to regulatory assets and liabilities. If the Company had adopted FAS 71, at December 31, 2008, additional future income tax liabilities and a regulatory asset in the amount of $1,434 million would have been recorded and would have been recoverable from future revenue. These changes will be applied retrospectively without restatement beginning January 1, 2009.

Intangible Assets
The CICA Handbook implemented revisions to standards dealing with intangible assets effective for fiscal years beginning on or after October 1, 2008. The revisions are intended to align the definition of an intangible asset in Canadian GAAP with that in International Financial Reporting Standards (IFRS) and U.S. GAAP. CICA Handbook Section 1000 "Financial Statement Concepts" was revised to remove material that permitted the recognition of assets that might not otherwise meet the definition of an asset and to add guidance from the International Accounting Standards Board's (IASB) "Framework for the Preparation and Presentation of Financial Statements" that helps distinguish assets from expenses. CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced CICA Handbook Section 3062 "Goodwill and Other Intangible Assets", gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. In addition, CICA Handbook Section 3450 "Research and Development Costs" will be withdrawn from the Handbook. The Company does not expect these changes to have a material effect on its financial statements.

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests
CICA Handbook Section 1582 "Business Combinations" is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". These standards will require a change in the measurement of non-controlling interest and will require the change to be presented as part of shareholders' equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling interest and non-controlling interest. These standards will be effective January 1, 2011, with early adoption permitted. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards
The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt IFRS, as issued by the IASB, effective January 1, 2011. In June 2008, the Canadian Securities Administrators proposed that Canadian public companies that are also U.S. Securities and Exchange Commission (SEC) registrants, such as TransCanada, retain the option to prepare their financial statements under U.S. GAAP instead of IFRS. In November 2008, the SEC issued for public comment a recommendation that, beginning in 2014, U.S. issuers be required to adopt IFRS using a phased-in approach based on market capitalization.

TransCanada is currently considering the impact a conversion to IFRS or U.S. GAAP would have on its accounting systems and financial statements. TransCanada's conversion project planning includes an analysis of project structure and governance, resources and training, analysis of key GAAP differences and a phased approach to the assessment of current accounting policies and implementation.

Under existing Canadian GAAP, TransCanada follows specific accounting policies unique to rate-regulated businesses. TransCanada is actively monitoring ongoing discussions and developments at the IASB regarding potential future guidance to clarify the applicability of certain aspects of rate-regulated accounting under IFRS. The IASB is expected to issue a proposed standard for rate-regulated businesses in 2009.

NOTE 4 SEGMENTED INFORMATION

NET INCOME[1]

Year ended December 31, 2008 (millions of dollars)	Pipelines	Energy	Corporate	Total
Revenues	**4,650**	**3,969**	**–**	**8,619**
Plant operating costs and other	**(1,732)**	**(1,326)**	**(4)**	**(3,062)**
Commodity purchases resold	**–**	**(1,511)**	**–**	**(1,511)**
Depreciation	**(989)**	**(200)**	**–**	**(1,189)**
	1,929	**932**	**(4)**	**2,857**
Financial charges	**(674)**	**–**	**(269)**	**(943)**
Financial charges of joint ventures	**(49)**	**(23)**	**–**	**(72)**
Interest income and other	**73**	**6**	**13**	**92**
Calpine bankruptcy settlements	**279**	**–**	**–**	**279**
Writedown of Broadwater LNG project costs	**–**	**(41)**	**–**	**(41)**
Income taxes	**(548)**	**(260)**	**206**	**(602)**
Non-controlling interests	**(108)**	**–**	**(22)**	**(130)**
Net Income	**902**	**614**	**(76)**	**1,440**

Year ended December 31, 2007 (millions of dollars)	Pipelines	Energy	Corporate	Total
Revenues	4,712	4,116	–	8,828
Plant operating costs and other	(1,670)	(1,353)	(7)	(3,030)
Commodity purchases resold	(72)	(1,887)	–	(1,959)
Depreciation	(1,021)	(158)	–	(1,179)
	1,949	718	(7)	2,660
Financial charges	(718)	1	(226)	(943)
Financial charges of joint ventures	(52)	(23)	–	(75)
Interest income and other	52	10	90	152
Gain on sale of assets	–	16	–	16
Income taxes	(470)	(208)	188	(490)
Non-controlling interests	(75)	–	(22)	(97)
Net Income	686	514	23	1,223

Year ended December 31, 2006 (millions of dollars)	Pipelines	Energy	Corporate	Total
Revenues	3,990	3,530	–	7,520
Plant operating costs and other	(1,380)	(1,024)	(7)	(2,411)
Commodity purchases resold	–	(1,707)	–	(1,707)
Depreciation	(927)	(131)	(1)	(1,059)
	1,683	668	(8)	2,343
Financial charges	(711)	–	(114)	(825)
Financial charges of joint ventures	(69)	(23)	–	(92)
Interest income and other	100	5	51	156
Gain on sale of assets	23	–	–	23
Income taxes	(410)	(198)	132	(476)
Non-controlling interests	(56)	–	(22)	(78)
Net income from continuing operations	560	452	39	1,051
Net income from discontinued operations				28
Net Income				1,079

(1) Certain expenses such as indirect financial charges and related income taxes are not allocated to business segments when determining their net income.

TOTAL ASSETS

December 31 (millions of dollars)	**2008**	2007
Pipelines	**25,020**	22,024
Energy	**12,006**	7,037
Corporate	**2,388**	1,269
	39,414	30,330

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Revenues[(1)]			
Canada – domestic	**4,599**	5,019	4,956
Canada – export	**1,125**	1,006	972
United States and other	**2,895**	2,803	1,592
	8,619	8,828	7,520

(1) Revenues are attributed based on the country where the product or service originated.

December 31 (millions of dollars)	**2008**	2007
Plant, Property and Equipment		
Canada	**18,041**	16,741
United States	**10,973**	6,564
Mexico	**175**	147
	29,189	23,452

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Pipelines	**1,854**	564	560
Energy	**1,266**	1,079	976
Corporate	**14**	8	36
	3,134	1,651	1,572

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

	2008			2007		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipelines[1]						
Canadian Mainline						
Pipeline	**8,740**	**4,269**	**4,471**	8,889	4,149	4,740
Compression	**3,373**	**1,399**	**1,974**	3,371	1,303	2,068
Metering and other	**344**	**140**	**204**	345	140	205
	12,457	**5,808**	**6,649**	12,605	5,592	7,013
Under construction	**16**	**–**	**16**	28	–	28
	12,473	**5,808**	**6,665**	12,633	5,592	7,041
Alberta System						
Pipeline	**5,518**	**2,637**	**2,881**	5,258	2,504	2,754
Compression	**1,552**	**914**	**638**	1,522	842	680
Metering and other	**846**	**317**	**529**	831	297	534
	7,916	**3,868**	**4,048**	7,611	3,643	3,968
Under construction	**354**	**–**	**354**	120	–	120
	8,270	**3,868**	**4,402**	7,731	3,643	4,088
ANR						
Pipeline	**976**	**69**	**907**	772	25	747
Compression	**579**	**61**	**518**	424	32	392
Metering and other	**686**	**50**	**636**	483	6	477
	2,241	**180**	**2,061**	1,679	63	1,616
Under construction	**31**	**–**	**31**	69	–	69
	2,272	**180**	**2,092**	1,748	63	1,685
GTN						
Pipeline	**1,482**	**215**	**1,267**	1,181	134	1,047
Compression	**562**	**63**	**499**	436	39	397
Metering and other	**134**	**23**	**111**	81	3	78
	2,178	**301**	**1,877**	1,698	176	1,522
Under construction	**30**	**–**	**30**	31	–	31
	2,208	**301**	**1,907**	1,729	176	1,553
Great Lakes	**1,875**	**744**	**1,131**	1,509	552	957
Foothills	**1,655**	**873**	**782**	1,647	819	828
Northern Border	**1,530**	**682**	**848**	1,232	528	704
Keystone – under construction	**1,361**	**–**	**1,361**	158	–	158
Other[2]	**2,078**	**566**	**1,512**	1,705	439	1,266
	8,499	**2,865**	**5,634**	6,251	2,338	3,913
	33,722	**13,022**	**20,700**	30,092	11,812	18,280
Energy						
Nuclear[3]	**1,604**	**364**	**1,240**	1,479	286	1,193
Natural gas/oil – Ravenswood[4]	**1,977**	**22**	**1,955**	n/a[5]	n/a	n/a
Natural gas – Other[6]	**1,702**	**504**	**1,198**	1,570	383	1,187
Hydro	**628**	**48**	**580**	503	28	475
Wind	**391**	**18**	**373**	288	6	282
Natural gas storage	**374**	**46**	**328**	358	33	325
Other	**156**	**82**	**74**	137	78	59
	6,832	**1,084**	**5,748**	4,335	814	3,521
Under construction[7]	**2,687**	**–**	**2,687**	1,606	–	1,606
	9,519	**1,084**	**8,435**	5,941	814	5,127
Corporate	**74**	**20**	**54**	60	15	45
	43,315	**14,126**	**29,189**	36,093	12,641	23,452

(1) In 2008, the Company capitalized $27 million (2007 – $14 million) relating to AFUDC.

(2) Pipelines – Other primarily includes assets of Iroquois, Portland, TQM, Tuscarora and Tamazunchale.

(3) Includes assets under capital lease relating to Bruce Power.

(4) TransCanada acquired Ravenswood on August 26, 2008.

(5) Not applicable, as there are no comparative amounts for prior years.

(6) Certain owned power generation facilities with long-term PPAs are accounted for as assets under operating leases. The net book value of these facilities was $77 million at December 31, 2008 (2007 – $78 million). Revenues of $14 million were recognized in 2008 (2007 – $16 million) through the sale of electricity under the related PPAs.

(7) Energy assets under construction primarily include expenditures for the Bruce A refurbishment and restart, and for construction of Halton Hills, Portland Energy, Kibby Wind and Coolidge.

NOTE 6 GOODWILL

The Company has recorded the following goodwill on its acquisitions in the U.S.:

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2007	281	–	281
Acquisition of ANR	2,235	–	2,235
Acquisition of additional interests in Great Lakes	573	–	573
Acquisition of additional interest in Tuscarora	3	–	3
Foreign exchange and adjustments	(459)	–	(459)
Balance at December 31, 2007	2,633	–	2,633
Acquisition of Ravenswood	**–**	**949**	**949**
Foreign exchange and adjustments	**749**	**66**	**815**
Balance at December 31, 2008	**3,382**	**1,015**	**4,397**

NOTE 7 OTHER ASSETS

December 31 (millions of dollars)	**2008**	2007
PPAs(1)	**651**	709
Prepaid operating lease(2)	**369**	n/a
Pension and other benefit plans *(Note 21)*	**234**	234
Regulatory assets *(Note 14)*	**201**	336
Fair value of derivative contracts *(Note 17)*	**191**	204
Loans and advances(3) *(Note 23)*	**140**	137
Deferred project development costs(4)	**116**	40
Equity investments(5)	**85**	63
Other	**241**	217
	2,228	1,940

(1) The following amounts related to the PPAs are included in the consolidated financial statements:

	2008			2007		
December 31 (millions of dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
PPAs	**915**	**264**	**651**	915	206	709

Amortization expense for the PPAs was $58 million for the year ended December 31, 2008 (2007 – $58 million; 2006 – $58 million). The expected annual amortization expense in each of the next five years is: 2009 – $58 million; 2010 – $58 million; 2011 – $57 million; 2012 – $57 million; and 2013 – $57 million.

(2) The balance at December 31, 2008 represents the long-term portion of a prepaid operating lease from the acquisition of Ravenswood. The expected annual operating lease expense in each of the next five years is US$10 million.

(3) The balance at December 31, 2008 represents a $140-million loan (2007 – $137 million) to the Aboriginal Pipeline Group (APG) to finance the APG for its one-third share of project development costs related to the Mackenzie Gas Pipeline project. The ability to recover this investment remains dependent upon the successful outcome of the project.

(4) The balance at December 31, 2008 includes $74 million (2007 – nil) related to the proposed expansion of the Keystone pipeline project and $42 million related to the Bison pipeline project. The balance of $40 million at December 31, 2007 related to the Broadwater LNG project and, in 2008, TransCanada wrote down $41 million of capitalized costs related to this project after the New York Department of State rejected a proposal to construct this facility.

(5) The balance primarily relates to the Company's 46.5 per cent ownership interest in TransGas.

NOTE 8 JOINT VENTURE INVESTMENTS

		TransCanada's Proportionate Share				
	Ownership Interest as at December 31,	Income/(Loss) Before Income Taxes Year ended December 31			Net Assets December 31	
(millions of dollars)	2008	**2008**	2007	2006	**2008**	2007
Pipelines						
Northern Border[1]		**59**	67	52	**479**	415
Iroquois	44.5%	**32**	25	25	**239**	163
TQM	50.0%	**12**	11	11	**69**	74
Keystone	61.9%[2]	**(7)**	n/a	n/a	**906**	207
Great Lakes[3]		**–**	13	69	**–**	–
Other	Various	**15**	13	6	**70**	48
Energy						
Bruce A	48.9%	**46**	8	75	**2,012**	1,640
Bruce B	31.6%	**136**	140	140	**429**	325
CrossAlta	60.0%	**44**	59	64	**56**	38
Cartier Wind	62.0%[4]	**12**	10	2	**365**	275
TC Turbines	50.0%	**9**	5	5	**31**	29
Portlands Energy	50.0%	**–**	–	–	**334**	269
ASTC Power Partnership	50.0%[5]	**–**	–	–	**70**	76
		358	351	449	**5,060**	3,559

(1) PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border in April 2006, increasing its general partnership interest to 50 per cent. Through TransCanada's 32.1 per cent ownership interest in PipeLines LP, Northern Border became a jointly controlled entity and TransCanada commenced proportionately consolidating its investment in Northern Border on a prospective basis. The Company's effective ownership of Northern Border, net of non-controlling interests, was 16.1 per cent at December 31, 2008 and 2007.

(2) In December 2007, ConocoPhillips exercised its option to become a 50 per cent partner with TransCanada in Keystone. As a result, TransCanada transferred $207 million of net assets and ConocoPhillips contributed $207 million of cash to each become a 50 per cent joint venture partner in Keystone. In 2008, TransCanada agreed to increase its equity ownership in the Keystone partnerships to 79.99 per cent. ConocoPhillips' equity ownership will be reduced concurrently to 20.01 per cent. TransCanada's increase in ownership is expected to occur as the Company funds 100 per cent of the construction expenditures until the participants' project capital contributions are aligned with the revised ownership interests. At December 31, 2008, TransCanada's equity ownership in the Keystone partnerships was 61.9 per cent (December 31, 2007 – 50.0 per cent), however, strategic, operational and financial decisions are made jointly with ConocoPhillips.

(3) In February 2007, TransCanada acquired an additional 3.6 per cent interest in Great Lakes, bringing its direct ownership interest to 53.6 per cent, and PipeLines LP acquired a 46.4 per cent interest in Great Lakes, giving TransCanada an indirect 14.9 per cent interest in Great Lakes. As a result of these transactions, the Company's effective ownership interest in Great Lakes, net of non-controlling interests, was 68.5 per cent at December 31, 2008 and 2007. TransCanada commenced consolidating its investment in Great Lakes on a prospective basis effective February 22, 2007.

(4) TransCanada proportionately consolidates its 62 per cent interest in the Cartier Wind assets. The first three phases of the six-phase Cartier Wind project, Baie-des-Sables, Anse-à-Valleau and Carleton, began operating in November 2006, 2007 and 2008, respectively.

(5) The Company has a 50 per cent ownership interest in ASTC Power Partnership, an Alberta partnership which holds the Sundance B PPA. The underlying power volumes related to this ownership interest are effectively transferred to TransCanada.

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Income			
Revenues	**1,264**	1,305	1,382
Plant operating costs and other	**(683)**	(736)	(686)
Depreciation	**(154)**	(150)	(163)
Financial charges and other	**(69)**	(68)	(84)
Proportionate share of joint venture income before income taxes	**358**	351	449

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Cash Flows			
Operating activities	**1,067**	420	645
Investing activities	**(2,031)**	(761)	(641)
Financing activities[1]	**952**	409	(31)
Effect of foreign exchange rate changes on cash and cash equivalents	**23**	(8)	9
Proportionate share of increase/(decrease) in cash and cash equivalents of joint ventures	**11**	60	(18)

(1) Financing activities included cash outflows resulting from distributions paid to TransCanada of $287 million in 2008 (2007 – $361 million; 2006 – $470 million) and cash inflows resulting from capital contributions paid by TransCanada of $1,067 million in 2008 (2007 – $771 million; 2006 – $452 million).

December 31 (millions of dollars)	**2008**	2007
Balance Sheet		
Cash and cash equivalents	**181**	170
Other current assets	**159**	343
Plant, property and equipment	**6,341**	4,283
Other assets/(deferred amounts), net	**45**	(69)
Current liabilities	**(793)**	(293)
Long-term debt	**(871)**	(873)
Future income taxes	**(2)**	(2)
Proportionate share of net assets of joint ventures	**5,060**	3,559

NOTE 9 ACQUISITIONS AND DISPOSITIONS

Acquisitions

Pipelines

Keystone
In 2008, TransCanada agreed to increase its equity ownership in the Keystone partnerships up to 79.99 per cent from 50 per cent, with ConocoPhillips' equity ownership being reduced concurrently to 20.01 per cent. The increase in ownership is expected to occur as TransCanada funds 100 per cent of the construction expenditures until the participants' project capital contributions are aligned with the revised ownership interests. In accordance with the agreement, TransCanada funded $362 million of cash calls, resulting in the acquisition of an incremental 12 per cent ownership interest for $176 million, bringing TransCanada's ownership interest to 62 per cent at December 31, 2008. TransCanada continues to proportionately consolidate the Keystone partnerships.

During 2008, Keystone purchased pipeline facilities located in Saskatchewan and Manitoba from the Canadian Mainline for use in the construction of the Keystone oil pipeline. The sale was completed in three phases for total proceeds of $65 million, with no gain recognized on the sale.

ANR and Great Lakes
On February 22, 2007, TransCanada acquired from El Paso Corporation 100 per cent of American Natural Resources Company and ANR Storage Company (collectively, ANR) and an additional 3.6 per cent interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes) for a total of US$3.4 billion, including US$491 million of assumed long-term debt. The acquisitions were accounted for using the purchase method of accounting. TransCanada began consolidating ANR and Great Lakes in the Pipelines segment after the acquisition date. The purchase price was allocated as follows:

Purchase Price Allocation

(millions of US dollars)	ANR	Great Lakes	Total
Current assets	250	4	254
Plant, property and equipment	1,617	35	1,652
Other non-current assets	83	–	83
Goodwill	1,945	32	1,977
Current liabilities	(179)	(3)	(182)
Long-term debt	(475)	(16)	(491)
Other non-current liabilities	(357)	(19)	(376)
	2,884	33	2,917

TC PipeLines, LP Acquisition of Interest in Great Lakes
On February 22, 2007, PipeLines LP acquired from El Paso Corporation a 46.4 per cent interest in Great Lakes for US$942 million, including US$209 million of assumed long-term debt. The acquisition was accounted for using the purchase method of accounting. TransCanada began consolidating Great Lakes in the Pipelines segment after the acquisition date. As of February 2007, TransCanada's effective ownership interest in Great Lakes was 68.5 per cent, comprising its direct ownership interest and its indirect ownership interest through PipeLines LP. The purchase price was allocated as follows:

Purchase Price Allocation

(millions of US dollars)	
Current assets	42
Plant, property and equipment	465
Other non-current assets	1
Goodwill	457
Current liabilities	(23)
Long-term debt	(209)
	733

The allocation of the purchase price for these transactions was made using the fair value of the net assets at the date of acquisition. Tolls charged by ANR and Great Lakes are subject to rate regulation based on historical costs. As a result, the regulated net assets, other than ANR's gas held for sale, were determined to have a fair value equal to their rate-regulated value.

Factors that contributed to goodwill included the opportunity to expand in the U.S. market and to gain a stronger competitive position in the North American gas transmission business. Goodwill related to TransCanada's ANR and Great Lakes transactions is not amortizable for tax purposes. Goodwill related to PipeLines LP's Great Lakes transaction is amortizable for tax purposes.

TC PipeLines, LP Private Placement Offering
In February 2007, PipeLines LP completed a private placement offering of 17,356,086 common units at a price of US$34.57 per unit. TransCanada acquired 50 per cent of the units for US$300 million. TransCanada also invested an additional US$12 million to maintain its general partnership interest in PipeLines LP. As a result of these additional investments, TransCanada's ownership in PipeLines LP increased to 32.1 per cent on February 22, 2007. The total private placement, together with TransCanada's additional investment, resulted in gross proceeds to PipeLines LP of US$612 million, which were used to partially finance its acquisition of a 46.4 per cent ownership interest in Great Lakes.

Tuscarora
In December 2007, PipeLines LP exercised its option to purchase Sierra Pacific Resources' remaining one per cent interest in Tuscarora Gas Transmission Company (Tuscarora) for US$2 million. In addition, PipeLines LP purchased TransCanada's one per cent interest in Tuscarora for US$2 million. Beginning December 2007, PipeLines LP owned 100 per cent of Tuscarora, resulting in TransCanada's effective ownership of 32.1 per cent, net of non-controlling interests.

In December 2006, PipeLines LP acquired an additional 49 per cent controlling general partner interest in Tuscarora for US$100 million in addition to indirectly assuming US$37 million of debt. The purchase price was allocated US$79 million to Goodwill, US$37 million to Long-Term Debt, and the balance primarily to Plant, Property and Equipment. Factors that contributed to goodwill included opportunities for expansion and a stronger competitive position. The goodwill recognized on this transaction is amortizable for tax purposes. PipeLines LP began consolidating its investment in Tuscarora in December 2006.

Northern Border
In April 2006, PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border Pipeline Company (Northern Border) for US$307 million, in addition to indirectly assuming US$122 million of debt. The purchase price was allocated US$114 million to Goodwill, US$122 million to Long-Term Debt and the balance primarily to Plant, Property and Equipment. Factors that contributed to goodwill included opportunities for expansion and a stronger competitive position. The goodwill recognized on this transaction is amortizable for tax purposes. As of April 2006, PipeLines LP owned 50 per cent of Northern Border, giving TransCanada effective ownership of 16.1 per cent, net of non-controlling interests.

Energy

Ravenswood
On August 26, 2008, TransCanada acquired from National Grid plc 100 per cent of the 2,480 MW Ravenswood power facility for US$2.9 billion, subject to certain post-closing adjustments. The acquisition was accounted for using the purchase method of accounting. TransCanada began consolidating Ravenswood in the Energy segment subsequent to the acquisition date. The preliminary allocation of the purchase price at December 31, 2008 was as follows:

Purchase Price Allocation

(millions of US dollars)	
Current assets	149
Plant, property and equipment	1,666
Other non-current assets	305
Goodwill	835
Current liabilities	(19)
Other non-current liabilities	(20)
	2,916

A preliminary allocation of the purchase price, subject to certain post-closing adjustments, has been made using fair values of the net assets at the date of acquisition. Factors that contributed to goodwill included the opportunity to expand the Energy segment further in the U.S. market and to gain a stronger competitive position in the North American power generation business. The goodwill recognized on this transaction is amortizable for tax purposes.

Dispositions

Pipelines

Northern Border Partners, L.P. Interest
In April 2006, TransCanada sold its 17.5 per cent general partner interest in Northern Border Partners, L.P., generating net proceeds of $33 million (US$30 million) and recognizing an after-tax gain of $13 million. The net gain was recorded in the Pipelines segment and the Company recorded a $10 million income tax charge on the transaction, including $12 million of current income tax expense.

Energy

Ontario Land Sale
In November 2007, TransCanada's Energy segment sold land in Ontario that had previously been held for development, generating net proceeds of $37 million and recognizing an after-tax gain of $14 million on the sale.

NOTE 10 LONG-TERM DEBT

Outstanding loan amounts (millions of dollars unless otherwise indicated)	Maturity Dates	**2008** Outstanding December 31	**2008** Interest Rate[(1)]	2007 Outstanding December 31	2007 Interest Rate[(1)]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2009 to 2020	**1,251**	**10.8%**	1,351	10.9%
U.S. dollars (2008 and 2007 – US$600)[(2)]	2012 to 2021	**734**	**9.5%**	594	9.5%
Medium-Term Notes					
Canadian dollars[(3)]	2009 to 2031	**3,653**	**5.3%**	3,413	6.1%
Senior Unsecured Notes					
U.S. dollars (2008 – US$4,723; 2007 – US$3,223)[(4)]	2009 to 2038	**5,751**	**6.3%**	3,161	6.0%
		11,389		8,519	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2010 to 2024	**439**	**11.5%**	501	11.6%
U.S. dollars (2008 and 2007 – US$375)	2012 to 2023	**457**	**8.2%**	368	8.2%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**502**	**7.4%**	607	7.2%
U.S. dollars (2008 and 2007 – US$33)	2026	**39**	**7.5%**	32	7.5%
		1,437		1,508	
TRANSCANADA PIPELINE USA LTD.					
Bank Loan					
U.S. dollars (2008 – US$700; 2007 – US$860)	2012	**857**	**2.4%**	850	5.7%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2008 and 2007 – US$444)	2010 to 2025	**541**	**9.1%**	435	9.1%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. Dollars (2008 and 2007 – US$400)	2010 to 2035	**488**	**5.4%**	399	5.4%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2008 – US$475; 2007 – US$507)	2011	**580**	**2.7%**	499	6.2%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2008 – US$430; 2007 – US$440)	2011 to 2030	**526**	**7.8%**	434	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Unsecured Notes					
U.S. dollars (2008 – US$64; 2007 – US$69)	2010 to 2012	**78**	**7.4%**	67	7.4%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes					
U.S. dollars (2008 – US$196; 2007 – US$211)[(5)]	2018	**236**	**6.1%**	205	6.1%
OTHER					
Senior Notes					
U.S. dollars (2008 – US$18; 2007 – US$17)	2011	**22**	**7.3%**	17	7.3%
		16,154		12,933	
Less: Current Portion of Long-Term Debt		**786**		556	
		15,368		12,377	

(1) Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

(2) Includes fair value adjustments for interest rate swap agreements on US$50 million of debt at December 31, 2008 and 2007.

(3) Includes fair value adjustments for interest rate swap agreements on $50 million of debt at December 31, 2008 (2007 – $150 million).

(4) Includes fair value adjustments for interest rate swap agreements on US$150 million of debt at December 31, 2008 and 2007.

(5) Senior Secured Notes are secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the long-term debt of the Company for the next five years are approximately as follows: 2009 – $786 million; 2010 – $531 million; 2011 – $1,014 million; 2012 – $1,370 million; and 2013 – $1,180 million.

Debt Shelf Programs – TransCanada PipeLines Limited

In January 2009, the Company filed a debt shelf prospectus in the U.S. qualifying for issuance US$3.0 billion of debt securities.

In March 2007, the Company filed debt shelf prospectuses in Canada and the U.S. qualifying for issuance $1.5 billion of Medium-Term Notes and US$1.5 billion of debt securities, respectively. Subsequent to the February 2009 debt issue discussed below, the Company had $300 million of remaining capacity available under the Canadian shelf prospectus.

In September 2007, the Company replaced the March 2007 U.S. debt shelf prospectus with a US$2.5 billion U.S. debt shelf prospectus. At December 31, 2008, the Company had fully utilized its capacity under the September 2007 U.S. shelf prospectus.

TransCanada PipeLines Limited

On February 17, 2009, TransCanada completed the issuance of Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. These notes were issued under the $1.5 billion debt shelf prospectus filed in Canada in March 2007.

On January 9, 2009, TransCanada issued US$750 million and US$1.25 billion of Senior Unsecured Notes maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. These notes were issued under the January 2009 U.S. debt shelf prospectus.

In August 2008, TransCanada issued $500 million of Medium-Term Notes maturing in August 2013, and bearing interest at 5.05 per cent under the March 2007 Canadian debt shelf prospectus.

In August 2008, TransCanada issued US$850 million and US$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. These notes were issued under the September 2007 U.S. debt shelf prospectus.

In October 2007, TransCanada issued US$1.0 billion of Senior Unsecured Notes under the U.S. debt shelf filed in September 2007.

NOVA Gas Transmission Ltd.

Debentures issued by NOVA Gas Transmission Ltd. (NGTL) in the amount of $225 million have retraction provisions that entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made to December 31, 2008.

TransCanada PipeLine USA Ltd.

In February 2007, TransCanada PipeLine USA Ltd. established a US$1.0 billion committed, unsecured, syndicated credit facility, consisting of a US$700-million five-year term loan and a US$300-million five-year, extendible revolving facility. There was an outstanding balance of US$700 million and US$860 million on the credit facility at December 31, 2008 and 2007, respectively. In 2008, the maturity date of the revolving portion of the facility was extended to February 2013.

TC PipeLines, LP

In February 2007, PipeLines LP increased its syndicated revolving credit and term loan facility in connection with its acquisition of a 46.4 per cent interest in Great Lakes. The amount available under the facility increased to US$950 million from US$410 million and consisted of a US$700-million senior term loan and a US$250-million senior revolving credit facility, with US$194 million of the senior term loan amount terminated upon closing of the Great Lakes acquisition. During 2008, an additional US$13 million (2007 – US$18 million) of the senior term loan was terminated due to principal repayments. There was an outstanding balance of US$475 million and US$507 million on the credit facility at December 31, 2008 and 2007, respectively.

Sensitivity

A one per cent change in interest rates would have the following effect assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on fair value of fixed interest rate debt	(895)	1,014
Effect on interest expense of variable interest rate debt	2	(2)

Financial Charges

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Interest on long-term debt	**970**	948	846
Interest on junior subordinated notes	**68**	43	n/a
Interest on short-term debt	**32**	48	23
Capitalized interest	**(141)**	(68)	(60)
Amortization and other financial charges[1]	**14**	(28)	16
	943	943	825

[1] Amortization and other financial charges in 2008 and 2007 included amortization of transaction costs and debt discounts calculated using the effective interest method.

The Company made interest payments of $833 million in 2008 (2007 – $966 million; 2006 – $771 million).

NOTE 11 LONG-TERM DEBT OF JOINT VENTURES

Outstanding loan amounts (millions of dollars)	Maturity Dates	**2008** Outstanding December 31(1)	**2008** Interest Rate(2)	2007 Outstanding December 31(1)	2007 Interest Rate(2)
NORTHERN BORDER PIPELINE COMPANY					
Senior Unsecured Notes (2008 – US$225; 2007 – US$232)	2009 to 2021	**275**	**7.7%**	229	7.7%
Bank Facility (2008 – US$96; 2007 – US$83)	2012	**116**	**3.4%**	82	5.3%
IROQUOIS GAS TRANSMISSION SYSTEM, L.P.					
Senior Unsecured Notes (2008 – US$160; 2007 – US$165)	2010 to 2027	**195**	**7.6%**	162	7.5%
Bank Loan (2007 – US$7)		**–**		7	7.4%
BRUCE POWER L.P. AND BRUCE POWER A L.P.					
Capital Lease Obligations	2018	**235**	**7.5%**	243	7.5%
Term Loan	2031	**95**	**7.1%**	n/a	
TRANS QUÉBEC & MARITIMES PIPELINE INC.					
Bonds	2009 to 2010	**137**	**6.0%**	137	6.0%
Term Loan	2011	**18**	**1.9%**	28	4.6%
OTHER	2009 to 2010	**5**	**5.5%**	15	4.5%
		1,076		903	
Less: Current Portion of Long-Term Debt of Joint Ventures		**207**		30	
		869		873	

(1) Amounts outstanding represent TransCanada's proportionate share.

(2) Interest rates are the effective interest rates except those pertaining to long-term debt issued for TQM's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates. At December 31, 2008, the effective interest rate resulting from swap agreements was 4.1 per cent on the Northern Border bank facility (2007 – nil). At December 31, 2007, the effective interest rate resulting from swap agreements was 7.5 per cent on the Iroquois bank loan.

The long-term debt of joint ventures is non-recourse to TransCanada, except that TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt of each joint venture is limited to the rights and assets of the joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. TQM's bonds are secured by a first interest in all TQM real and immoveable property and rights, a floating charge on all residual property and assets, and a specific interest on bonds of TQM Finance Inc. and on rights under all licenses and permits relating to the TQM pipeline system and natural gas transportation agreements.

Subject to meeting certain requirements, the Bruce Power capital lease agreements provide for renewals commencing January 1, 2019. The first renewal is for a period of one year and each of 12 renewals thereafter is for a period of two years.

The Company's proportionate share of principal repayments for the next five years resulting from maturities and sinking fund obligations of the non-recourse joint venture debt is approximately as follows: 2009 – $194 million; 2010 – $212 million; 2011 – $30 million; 2012 – $126 million; and 2013 – $8 million.

The Company's proportionate share of principal payments for the next five years resulting from the capital lease obligations of Bruce Power is approximately as follows: 2009 – $13 million; 2010 – $13 million; 2011 – $15 million; 2012 – $18 million; and 2013 – $20 million.

In September 2008, Bruce A entered into a $193 million unsecured term loan, maturing December 2031 and bearing interest at 7.12 per cent.

In April 2007, Northern Border established a US$250-million five-year unsecured bank facility. A portion of the bank facility was drawn to refinance US$150 million of the Senior Unsecured Notes that matured on May 1, 2007.

Sensitivity

A one per cent change in interest rates would have the following effects assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on fair value of fixed interest rate debt	(39)	44
Effect on interest expense of variable interest rate debt	1	(1)

Financial Charges of Joint Ventures

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Interest on long-term debt	**45**	50	67
Interest on capital lease obligations	**18**	18	19
Short-term interest and other financial charges	**7**	4	3
Deferrals and amortization	**2**	3	3
	72	75	92

The Company's proportionate share of the interest payments of joint ventures was $50 million in 2008 (2007 – $45 million; 2006 – $73 million).

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $18 million in 2008 (2007 – $18 million; 2006 – $20 million).

NOTE 12 JUNIOR SUBORDINATED NOTES

		2008		2007	
Outstanding loan amount (millions of dollars)	Maturity Dates	**Outstanding December 31**	**Effective Interest Rate**	Outstanding December 31	Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2008 and 2007 – US$1,000)	2017	**1,213**	**6.5%**	975	6.5%

In April 2007, TransCanada PipeLines Limited (TCPL) issued US$1.0 billion of Junior Subordinated Notes, maturing in 2067 and bearing interest of 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate, reset quarterly to the three-month London Interbank Offered Rate (LIBOR) plus 221 basis points. The Company has the option to defer payment of interest for periods of up to ten years without giving rise to a default and without permitting acceleration of payment under the terms of the Junior Subordinated Notes. The Company would be prohibited from paying dividends during any deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017 at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes. The Junior Subordinated Notes were issued under the U.S. debt shelf prospectus filed in March 2007.

Sensitivity

A one per cent change in interest rates would have the following effects assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on fair value of Junior Subordinated Notes	(45)	49

NOTE 13 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2008**	2007
Fair value of derivative contracts *(Note 17)*	**694**	205
Regulatory liabilities *(Note 14)*	**551**	525
Employee benefit plans *(Note 21)*	**219**	196
Asset retirement obligations *(Note 20)*	**114**	88
Other	**141**	93
	1,719	1,107

NOTE 14 REGULATED BUSINESSES

TransCanada's regulated businesses include Canadian and U.S. natural gas pipelines. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers. They arise from certain costs and revenues generated in the current period or in prior periods that may be collected from or refunded to shippers if, through the rate-setting process, it is found that revenues were over- or under-collected. Regulatory assets and liabilities are only recognized when approved by the applicable regulatory authorities. In addition to GAAP financial reporting, TransCanada's regulated pipelines file financial reports using accounting regulations required by their respective regulators.

Canadian Regulated Operations

Canadian natural gas transmission services are supplied under gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the applicable regulatory authorities.

Rates charged by TransCanada's wholly owned and partially owned Canadian regulated pipelines are set typically through a process that involves filing an application with the regulators for a change in rates. Regulated rates are underpinned by the total annual revenue requirement, which comprises specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TransCanada's Canadian regulated pipelines have generally been subject to a cost-of-service model wherein forecasted costs, including a return on capital, equal the revenues for the upcoming year. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Costs for which the regulator does not allow the difference between actual and forecast to be deferred are included in the determination of net income in the year they are incurred.

The Canadian Mainline, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act (Canada)*. The Alberta System is regulated by the AUC primarily under the provisions of the *Gas Utilities Act (Alberta)* and the *Pipeline Act (Alberta)*. The AUC regulates the construction and operation of facilities, and the terms and conditions of services, including rates for the Alberta System. The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's other Canadian regulated natural gas transmission systems. The Alberta System has filed an application with the NEB to change its regulatory jurisdiction from the AUC to the NEB. The NEB's decision is expected in first quarter 2009.

Canadian Mainline

The Canadian Mainline currently operates under a five-year tolls settlement, which is effective January 1, 2007, to December 31, 2011. Canadian Mainline's cost of capital for establishing tolls under the settlement reflects a rate of return on common equity (ROE) as determined by the NEB's ROE formula, on a deemed common equity ratio of 40 per cent. The allowed ROE in 2008 for Canadian Mainline was 8.71 per cent (2007 – 8.46 per cent). The remaining capital structure consists of short- and long-term debt following the agreed-upon redemption of US$460 million of Preferred Securities in 2007.

The settlement also establishes the Canadian Mainline's fixed operations, maintenance and administrative (OM&A) costs for each year of the five years. Any variance between actual OM&A costs and those agreed to in the settlement accrue to TransCanada from 2007 to 2009. Variances in OM&A costs will be shared equally between TransCanada and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. There are also performance-based incentive arrangements that provide mutual benefits to both TransCanada and its customers.

Alberta System

In March 2008, NOVA Gas Transmission Ltd. (NGTL) reached a revenue requirement settlement with interested stakeholders for 2008 and 2009 on the Alberta System. In December 2008, the AUC approved the 2008-2009 Revenue Requirement Settlement Application, which is effective for the full two-year period.

As part of the settlement, fixed costs were established for certain operating costs, ROE and income taxes. Any variances between actual costs and those agreed to in the settlement accrue to TransCanada, subject to ROE and income tax adjustment mechanisms. All other costs of the revenue requirement are treated on a flow-through basis.

Other Canadian Pipelines

The NEB approves pipeline tolls on an annual cost of service basis for Foothills and TQM. The NEB allows each pipeline to charge a schedule of tolls based on the estimated cost of service. This schedule of tolls is used for the current year until a new toll filing is made for the following year. Differences between the estimated cost of service and the actual cost of service are calculated and reflected in the subsequent year's tolls.

The ROE for Foothills, which is based on the NEB-allowed ROE formula, was 8.71 per cent in 2008 (2007 – 8.46 per cent) on a deemed equity component of 36 per cent.

In September 2008, the NEB approved TQM's application for a three-year partial negotiated settlement with interested parties concerning all cost of service matters, with the exception of cost of capital and associated income taxes, for the years 2007 to 2009. In December 2007, TQM filed a cost of capital application with the NEB for the years 2007 and 2008, which requests approval of an 11 per cent return on deemed common equity of 40 per cent. An NEB hearing on the application concluded in October 2008 and a decision from the NEB is expected in early 2009. TQM currently is subject to the NEB ROE formula on deemed common equity of 30 per cent. TQM tolls remain in effect on an interim basis pending a decision on the application. Any adjustments to the interim tolls will be recorded in accordance with the decision.

U.S. Regulated Operations

TransCanada's wholly owned and partially owned U.S. pipelines are 'natural gas companies' operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* and the *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The *Natural Gas Act of 1938* grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce.

ANR

ANR's operations are regulated primarily by the FERC. ANR's natural gas storage and transportation services regulated by the FERC also operate under approved tariff rates. ANR Pipeline's rates were established pursuant to a settlement approved by a FERC order issued in February 1998 and became effective in November 1997. These tariffs include maximum and minimum rate levels for services and permit ANR to discount or negotiate rates on a non-discriminatory basis. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC in April 1990 and became effective in June 1990. None of ANR's FERC-regulated operations are required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a case for new rates.

GTN

GTN is regulated by the FERC. Both of GTN's natural gas pipeline systems, the GTN System and North Baja, operate in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. The pipelines are permitted to discount or negotiate these rates on a non-discriminatory basis. The GTN System and its customers reached a rate case settlement in November 2007 that was approved by the FERC in January 2008. GTN's financial results in 2007 reflected the terms of the settlement. In 2008, the GTN System refunded to customers amounts collected above the settlement rates for the period from January 1, 2007 through October 31, 2007. Under the settlement, a five-year moratorium was established during which the GTN System and the settling parties are prohibited from taking certain actions under the *Natural Gas Act of 1938*, including any filings. The GTN System is also required to file a rate case within seven years. Rates for capacity on North Baja were established in 2002 in the FERC's initial order certifying construction and operations of North Baja.

Great Lakes

Great Lakes' rates and tariffs are regulated by the FERC. In 2000, Great Lakes negotiated an overall rate settlement with its customers that established the rates currently in effect. The settlement expired October 31, 2005, with no requirement to file for new rates at any time, nor is Great Lakes prohibited from filing such a rate case. Great Lakes' services are provided pursuant to its FERC-approved tariff, which includes, among other factors, maximum and minimum rate levels for services and permits Great Lakes to negotiate or discount rates on a non-discriminatory basis.

Portland

In April 2008, Portland filed a general rate case under the *Natural Gas Act of 1938*, in accordance with the terms of its previous settlement approved by the FERC in 2003. The proposed tariffs, which included a rate increase of approximately six per cent, became effective September 1, 2008, subject to refund, in accordance with a FERC order dated May 1, 2008. The rate case hearing is scheduled to begin in July 2009.

Northern Border

Northern Border and its customers reached a settlement in September 2006 that was approved by the FERC in November 2006. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border's system. The settlement provided for seasonal rates, which vary on a monthly basis, for short-term transportation services. It also included a three-year moratorium on filing rate cases and on participants filing challenges to rates, and required that Northern Border file a general rate case within six years. Northern Border is required to provide services under negotiated and discounted rates on a non-discriminatory basis.

Regulatory Assets and Liabilities

Year ended December 31 (millions of dollars)	**2008**	2007	Remaining Recovery/ Settlement Period
			(years)
Regulatory Assets			
Unrealized losses on derivatives(1)	**67**	106	1 - 5
Foreign exchange on long-term debt principal(2)	**32**	34	21
Deferred income tax on carrying costs capitalized during construction of utility plant(3)	**26**	20	n/a
Unamortized issue costs on Preferred Securities(4)	**18**	19	18
Phase II preliminary expenditures(5)	**16**	18	7
Transitional other benefit obligations(6)	**15**	16	8
Unamortized post-retirement benefits(7)	**11**	13	3 - 5
Operating and debt-service regulatory assets(8)	**–**	85	n/a
Other	**16**	25	n/a
Total Regulatory Assets (Other Assets)	**201**	336	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities(8)	**234**	3	1
Foreign exchange gain on redemption of Preferred Securities, net of income tax of $10 million (2007 – $15 million)(4)	**101**	150	3
Foreign exchange on long-term debt(9)	**70**	266	4 - 21
Post-retirement benefits other than pension(10)	**58**	38	n/a
Unamortized gains on derivatives(1)	**24**	n/a	4
Fuel tracker(11)	**23**	29	n/a
Negative salvage(12)	**16**	17	n/a
Other	**25**	22	n/a
Total Regulatory Liabilities (Deferred Amounts)	**551**	525	

(1) Unrealized gains and losses on derivatives represent the net position of fair value gains and losses on cross-currency and interest-rate swaps, and forward foreign currency contracts, which act as economic hedges. The cross-currency swaps pertain to foreign debt instruments associated with the Canadian Mainline, Foothills and Alberta System. Pre-tax operating results would have been $63 million higher in 2008 (2007 – $22 million lower) if these amounts had not been recorded as regulatory assets and liabilities.

(2) The foreign exchange on long-term debt principal account in the Alberta System, as approved by the AUC, is designed to facilitate the recovery or refund of foreign exchange gains and losses over the life of the foreign currency debt issues. Realized gains and losses and estimated net future losses on foreign currency debt are amortized over the remaining years of the longest outstanding U.S. debt issue. The annual amortization amount is included in the determination of tolls for the year. Pre-tax operating results would have been $2 million lower in 2008 (2007 – $1 million higher) if these amounts had not been recorded as regulatory assets.

(3) Rate-regulated accounting allows the capitalization of both equity and interest components for the carrying costs of funds used during the construction of utility assets. The capitalized AFUDC is depreciated as part of the total depreciable plant after the utility assets are placed in service. Equity AFUDC is not subject to income taxes, therefore, a deferred tax provision is recorded with an offset to a corresponding regulatory asset.

(4) In July 2007, the Company redeemed the US$460-million 8.25 per cent Preferred Securities that underpinned the Canadian Mainline's investment base. Upon redemption of the securities, there was a realized foreign exchange gain that will flow through, net of income tax, to Canadian Mainline's customers over the five years of the current rate case settlement. In addition, the issue costs on the Preferred Securities will be amortized over 20 years beginning January 1, 2007. GAAP would have required the foreign exchange gain and the unamortized issue costs to be included in the operating results of the Canadian Mainline in the year the securities were redeemed if these amounts had not been recorded as regulatory assets. This would have (decreased)/increased 2008 pre-tax operating results by $(54) million and $1 million (2007 – $165 million and $(19) million) related to the foreign exchange gain and issue costs, respectively.

(5) Phase II preliminary expenditures are costs incurred by Foothills prior to 1981 related to development of Canadian facilities to deliver Alaskan gas. These costs have been approved by the regulator for collection through straight-line amortization over the period November 2002 to December 2015. Pre-tax operating results would have been $2 million higher in 2008 (2007 – $2 million higher) if these amounts had not been recorded as regulatory assets.

(6) The regulatory asset with respect to the annual transitional other benefit obligations is being amortized over 17 years to December 2016, at which time the full transitional obligation will have been recovered through tolls. Pre-tax operating results would have been $1 million higher in 2008 (2007 – $2 million higher) if these amounts had not been recorded as regulatory assets.

(7) An amount is recovered in ANR's rates for post-retirement benefits other than pensions (PBOP). A curtailment and special termination benefits charge related to PBOP for a closed group of retirees was recorded as a regulatory asset and is being amortized through 2011. Pre-tax operating results would have been $3 million higher in 2008 (2007 – $3 million higher) if these amounts had not been recorded as regulatory assets.

(8) Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the immediate following calendar year. Pre-tax operating results would have been $316 million higher in 2008 (2007 – $152 million lower) if these amounts had not been recorded as regulatory assets and liabilities.

(9) Foreign exchange on long-term debt of the Canadian Mainline, Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historic foreign exchange rate. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of rate-regulated accounting, GAAP would have required the inclusion of these unrealized gains or losses either on the balance sheet or income statement depending on whether the foreign debt is designated as a hedge of the Company's net investment in foreign assets.

(10) An amount is recovered in ANR's rates for PBOP. This regulatory liability represents the difference between the amount collected in rates and the amount of PBOP expense. No PBOP expense was recorded in 2008 and 2007.

(11) ANR's tariff stipulates a fuel tracker mechanism to track over- or under-collections of fuel used and gas lost and unaccounted for (collectively, fuel). The fuel tracker represents the difference between the value of 'in-kind' natural gas retained from shippers and the actual amount of natural gas used for fuel by ANR. Any over- or under-collections are returned to or collected from shippers through a prospective annual adjustment to fuel retention rates. A regulatory asset or liability is established for the difference between ANR's actual fuel use and amounts collected through its fuel rates. Pre-tax operating results are not affected by the fuel tracker mechanism.

(12) ANR collects in its current rates an allowance for negative salvage related to its offshore transmission and gathering facilities. The allowance for negative salvage is collected as a component of depreciation expense and recorded to a negative salvage account within the reserve for accumulated depreciation. Costs associated with the abandonment of offshore transmission and with gathering facilities are recorded against the negative salvage reserve.

As prescribed by regulators, the taxes payable method of accounting for income taxes is used for toll-making purposes on Canadian regulated natural gas transmission operations. As permitted by GAAP at December 31, 2008, this method is also used for accounting purposes. Consequently, future income tax liabilities have not been recognized, as it is expected they will be recovered through future rates when the amounts become payable. In the absence of rate-regulated accounting, GAAP would have required the recognition of future income tax liabilities. If the liability method of accounting had been used, additional future income tax liabilities would have been recorded at December 31, 2008 and would have been recoverable from future revenues. The liability method of accounting is used for both accounting and toll-making purposes for the U.S. natural gas transmission operations. Under this method, future income tax assets and liabilities are recognized based on the differences between financial statement carrying amounts and the tax basis of the assets and liabilities. This method is also used for toll-making purposes for the U.S. natural gas transmission operations. As a result, current year's revenues include a tax provision that is calculated based on the liability method of accounting and there is no recognition of a related regulatory asset or liability. Effective January 1, 2009, the Company will be adopting policies consistent with FAS 71 to account for its rate-regulated pipelines, as discussed in Note 3.

NOTE 15 NON-CONTROLLING INTERESTS

The Company's non-controlling interests included in the consolidated balance sheet were as follows:

December 31 (millions of dollars)	**2008**	2007
Non-controlling interest in PipeLines LP	**721**	539
Preferred shares of subsidiary	**389**	389
Non-controlling interest in Portland	**84**	71
	1,194	999

The Company's non-controlling interests included in the consolidated income statement are as follows:

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Non-controlling interest in PipeLines LP	**62**	65	43
Preferred share dividends of subsidiary	**22**	22	22
Non-controlling interest in Portland	**46**	10	13
	130	97	78

The non-controlling interests in PipeLines LP and Portland as at December 31, 2008 represented the 67.9 per cent and 38.3 per cent interest, respectively, not owned by TransCanada (2007 – 67.9 per cent and 38.3 per cent, respectively).

TransCanada received revenues of $2 million from PipeLines LP in 2008 (2007 – $2 million; 2006 – $1 million) and $7 million from Portland in 2008 (2007 – $7 million; 2006 – $6 million) for services it provided.

Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate Per Share	Redemption Price Per Share	**2008**	2007
	(thousands)			(millions of dollars)	(millions of dollars)
Cumulative First Preferred Shares of Subsidiary					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

The authorized number of preferred shares of TCPL issuable in series is unlimited. All of the cumulative first preferred shares of TCPL are without par value.

On or after October 15, 2013, TCPL may redeem the Series U shares at $50 per share and on or after March 5, 2014, TCPL may redeem the Series Y shares at $50 per share.

NOTE 16 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2006	487,236	4,755
Exercise of options	1,739	39
Outstanding at December 31, 2006	488,975	4,794
Issuance of common shares(1)	45,390	1,683
Dividend reinvestment and share purchase plan	4,147	157
Exercise of options	1,253	28
Outstanding at December 31, 2007	539,765	6,662
Issuance of common shares(1)	**69,805**	**2,363**
Dividend reinvestment and share purchase plan	**5,976**	**218**
Exercise of options	**925**	**21**
Outstanding at December 31, 2008	**616,471**	**9,264**

(1) Net of underwriting commissions and future income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

In July 2008, TransCanada filed a final short form base shelf prospectus in Canada and the U.S. to allow for the offering of up to $3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until August 2010. This shelf prospectus replaced the previous base shelf prospectus filed in January 2007. The Company issued the following equity under the July 2008 prospectus:

- In fourth quarter 2008, TransCanada completed a public offering of common shares at a purchase price of $33.00 per share. The entire issue of 35.1 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.2 billion.

In January 2007, TransCanada filed a short form base shelf prospectus in Canada and the U.S. to allow for the offering of up to $3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until February 2009. The Company issued the following equity under the January 2007 prospectus:

- In first quarter 2007, the Company completed a public offering of common shares at a purchase price of $38.00 per share. The entire issue of 45.4 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.7 billion.
- In May 2008, TransCanada completed a public offering of common shares at a purchase price of $36.50 per share. The entire issue of 34.7 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.3 billion.

Net Income per Share

During the year, the weighted average number of common shares of 569.6 million and 571.5 million (2007 – 529.9 million and 532.5 million; 2006 – 488.0 million and 490.6 million) were used to calculate basic and diluted earnings per share, respectively. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

Stock Options

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding January 1, 2006	8,714	$22.67	6,300
Granted	1,841	$34.48	
Exercised	(1,739)	$21.44	
Forfeited	(17)	$30.98	
Outstanding at December 31, 2006	8,799	$25.37	5,888
Granted	1,083	$38.10	
Exercised	(1,253)	$22.77	
Forfeited	(20)	$35.08	
Outstanding at December 31, 2007	8,609	$27.32	6,118
Granted	**872**	**$39.75**	
Exercised	**(925)**	**$22.26**	
Forfeited	**(55)**	**$35.23**	
Outstanding at December 31, 2008	**8,501**	**$29.10**	**6,461**

Stock options outstanding at December 31, 2008, were as follows:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Life
	(thousands)		(years)	(thousands)		(years)
$10.03 to $20.58	1,242	$17.22	1.9	1,242	$17.22	1.9
$20.59 to $21.86	927	$21.42	3.1	927	$21.42	3.1
$22.33 to $24.49	766	$22.33	1.2	766	$22.33	1.2
$24.61 to $26.85	971	$26.84	2.1	971	$26.84	2.1
$30.09 to $33.08	1,527	$31.33	3.8	1,314	$31.04	3.7
$35.23	1,106	$35.23	4.2	854	$35.23	4.2
$36.67 to $38.10	983	$38.07	5.1	341	$38.02	5.1
$38.14 to $39.75	979	$39.57	6.1	46	$38.29	5.3
	8,501	$29.10	3.4	6,461	$26.31	3.3

An additional 4.0 million common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2008. In 2008, TransCanada issued 871,733 options to purchase common shares at an average price of $39.75 under the Company's Stock Option Plan and the weighted average fair value of each option was determined to be $3.27 (2007 – $4.22; 2006 – $3.53). The Company used the Black-Scholes model for determining the fair value of options granted applying the following weighted average assumptions for 2008: four years of expected life (2007 and 2006 – four years); 1.5 per cent interest rate (2007 and 2006 – 4.1 per cent); 28 per cent volatility (2007 – 15 per cent; 2006 – 14 per cent); and 4.5 per cent dividend yield (2007 – 3.6 per cent; 2006 – 3.7 per cent). The amount expensed for stock options, with a corresponding increase in contributed surplus, was $4 million in 2008 (2007 – $4 million; 2006 – $3 million).

The total intrinsic value of options exercised in 2008 was $15 million. As at December 31, 2008, the aggregate intrinsic value was $48 million for each of the total currently exercisable options and the total outstanding options. In 2008, the 1.4 million shares that vested had a fair value of $45 million.

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Under certain circumstances, each common share is entitled to one right that entitles certain holders to purchase two common shares of the Company for the price of one.

Dividend Reinvestment and Share Purchase Plan

Commencing in 2007, TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount to participants in the Company's Dividend Reinvestment and Share Purchase Plan (DRP). Under the DRP, eligible shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. The discount was set at two per cent commencing with the dividend payable in April 2007 and was increased to three per cent for the dividend payable in January 2009. The Company reserves the right to alter the discount or return to purchasing shares on the open market at any time. In accordance with the DRP, dividends of $218 million were paid in 2008 by the issuance from treasury of 6.0 million common shares. In 2007, dividends of $157 million were paid by the issuance from treasury of 4.1 million common shares. Prior to the April 2007 dividend, TransCanada purchased shares on the open market and provided them to DRP participants at cost.

NOTE 17 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk, and liquidity risk. TransCanada engages in risk management activities with the primary objective being to protect earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee. The Board of Directors also has a Governance Committee that assists in overseeing the risk management activities of TransCanada. The Governance Committee monitors, reviews with management and makes recommendations related to TransCanada's risk management programs and policies on an ongoing basis.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management policy to manage exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and oil products. A number of strategies are used to mitigate these exposures, including the following:

- Subject to the Company's overall risk management policies, the Company commits a significant portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.
- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sales price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfill the Company's power sales commitments is purchased with contracts or fulfilled through power generation, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions and derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but are not within the scope of CICA Handbook Section 3855 "Financial Instruments – Recognition and Measurement", as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements exemption. Certain other contracts are not within the scope of Section 3855 as they are considered to meet other exemptions.

TransCanada manages its exposure to seasonal natural gas price spreads in its natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to price movements of natural gas. Fair value adjustments recorded each period on proprietary natural gas storage inventory and these forward contracts may not be representative of the amounts that will be realized on settlement.

Natural Gas Inventory Price Risk

At December 31, 2008, $76 million (2007 – $190 million) of proprietary natural gas inventory was included in Inventories. Effective April 2007, TransCanada began valuing its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas less selling costs. The Company did not have any proprietary natural gas inventory held in storage prior to April 2007. In 2008, the net change in fair value of proprietary natural gas held in inventory was a net unrealized loss of $7 million (2007 – nil), which was recorded as a decrease to Revenue and Inventory. In 2008, the net change in fair value of natural gas forward purchases and sales contracts was a net unrealized gain of $7 million (2007 – $10 million) which was included in Revenues.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and/or market interest rates.

A portion of TransCanada's earnings from its Pipelines and Energy operations is generated in U.S. dollars and is subject to currency fluctuations. The performance of the Canadian dollar relative to the U.S. dollar can affect TransCanada's earnings. This foreign exchange impact is offset by certain related debt and financing costs being denominated in U.S. dollars and by the Company's hedging activities. Due to its increased U.S. operations, TransCanada has a greater exposure to U.S. currency fluctuations than in prior years.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposure of the Canadian Mainline, Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. These gains and losses are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt, which subjects it to interest rate cash flow risk. The Company uses a combination of forwards, interest rate swaps and options to manage its exposure to this risk.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, forward foreign exchange contracts, cross-currency interest rate swaps and foreign exchange options. At December 31, 2008, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.2 billion (US$5.9 billion) (2007 – $4.7 billion (US$4.7 billion)) and a fair value of $5.9 billion (US$4.8 billion) (2007 – $4.8 billion (US$4.8 billion)). In January 2009, the Company issued an additional US$2.0 billion of long-term debt and designated it as a hedge of the net U.S. dollar investment in foreign operations. At December 31, 2008, $254 million was included in Deferred Amounts for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amount for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability) *December 31 (millions of dollars)*	**2008** **Fair Value**	**2008** **Notional or Principal Amount**	2007 Fair Value	2007 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2009 to 2014)	**(218)**	**U.S. 1,650**	77	U.S. 350
U.S. dollar forward foreign exchange contracts (maturing 2009)	**(42)**	**U.S. 2,152**	(4)	U.S. 150
U.S. dollar options (maturing 2009)	**6**	**U.S. 300**	3	U.S. 600
	(254)	**U.S. 4,102**	76	U.S. 1,100

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact resulting from its exposure to market risk. VaR estimates the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number calculated and used by TransCanada reflects the 95 per cent probability that the daily change resulting from normal market fluctuations in its liquid positions will not exceed the reported VaR. The VaR methodology is a statistically-calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the Pipelines segment as the rate-regulated nature of the pipeline business reduces the impact of market risks. The Company's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated VaR was $23 million at December 31, 2008 (2007 – $8 million). The increase from December 31, 2007 was primarily due to the Ravenswood acquisition.

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using master netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that these processes will protect it against all losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consisted primarily of the carrying amount, which approximates fair value, of non-derivative financial assets, such as accounts receivable, as well as the fair value of derivative financial assets.

The Company does not have significant concentrations of counterparty credit risk with any individual counterparties and the majority of counterparty credit exposure is with counterparties who are investment grade. At December 31, 2008, there were no significant amounts past due or impaired.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-credit worthy counterparties.

During the deterioration of global financial markets in 2008, TransCanada continued to closely monitor and reassess the creditworthiness of its counterparties, including financial institutions. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it is deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market risk and counterparty credit risk when making business decisions.

Certain subsidiaries of Calpine Corporation (Calpine) filed for bankruptcy protection in both Canada and the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland Natural Gas Transmission System (PNGTS) reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and PNGTS received initial distributions of 9.4 million common shares and 6.1 million common shares of Calpine, respectively, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were subsequently sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and will be passed on to shippers on these systems. At December 31, 2008, $22 million remained in regulatory liabilities for these claims.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure that, under both normal and stressed conditions, it always has sufficient cash and credit facilities to meet its obligations when due, without incurring unacceptable losses or damage to the Company's reputation.

Management forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed under the heading Capital Management in this note.

At December 31, 2008, the Company had committed revolving bank lines of US$1.0 billion, $2.0 billion and US$300 million maturing in November 2010, December 2012 and February 2013, respectively. As of December 31, 2008, no draws were made on these facilities as the Company has continued to have largely uninterrupted access to the Canadian commercial paper market on competitive terms. In January 2009, TransCanada filed a new US$3.0 billion debt shelf in the U.S. to supplement the $1.8 billion and $1.0 billion of capacity available under its existing equity and Canadian debt shelves, respectively. The Company has US$1.0 billion of capacity remaining available under its January 2009 U.S. debt shelf.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2008:

Contractual Repayments of Financial Liabilities[1]

		Payments Due by Period			
(millions of dollars)	Total	2009	2010 and 2011	2012 and 2013	2014 and Thereafter
Notes payable	1,702	1,702	–	–	–
Long-term debt and junior subordinated notes	17,367	786	1,545	2,550	12,486
Long-term debt of joint ventures	1,076	207	270	172	427
Total contractual repayments	20,145	2,695	1,815	2,722	12,913

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this Note.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2009	2010 and 2011	2012 and 2013	2014 and Thereafter
Long-term debt and junior subordinated notes	15,170	1,150	2,151	1,950	9,919
Long-term debt of joint ventures	328	61	76	56	135
Total interest payments	15,498	1,211	2,227	2,006	10,054

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2008, this overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Shareholders' Equity. Net debt is comprised of Notes Payable, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TransCanada's joint ventures.

The capital structure at December 31 was as follows:

(millions of dollars)	**2008**	2007
Notes payable	**1,685**	407
Long-term debt	**16,154**	12,933
Junior subordinated notes	**1,213**	975
Cash and cash equivalents	**(1,117)**	(333)
Net debt	**17,935**	13,982
Non-controlling interests	**1,194**	999
Shareholders' equity	**12,898**	9,785
Total equity	**14,092**	10,784
Total capital	**32,027**	24,766

Fair Values

The fair value of financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts approximates their carrying amounts due to the nature of the item and/or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates. The fair value of power, natural gas and oil products derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes are used. Credit risk has been taken into consideration when calculating fair values.

Valuation techniques that refer to observable market data or estimated market prices may also be used to calculate fair value. These include comparisons with similar instruments that have observable market prices, option pricing models and other valuation techniques commonly used by market participants. Fair values determined using valuation models require the use of assumptions about the amount and timing of estimated future cash flows and discount rates. In making these assumptions, the Company looks primarily to readily observable external market input factors such as interest rate yield curves, currency rates and price and rate volatilities, as applicable.

The fair value of the Company's Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments and, when such information was not available, was estimated by discounting future payments of interest and principal at estimated interest rates that were made available to the Company.

Fair Value of Long-Term Debt and Other Long-Term Securities

The carrying and fair values of long-term debt and other long-term securities were as follows:

	2008		2007	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt				
TransCanada PipeLines Limited[1]	**11,389**	**10,583**	8,519	9,400
NOVA Gas Transmission Ltd.	**1,437**	**1,534**	1,508	1,877
TransCanada PipeLine USA Ltd.	**857**	**857**	850	850
ANR Pipeline Company	**541**	**570**	435	573
Gas Transmission Northwest Corporation	**488**	**393**	399	383
TC PipeLines, LP	**580**	**580**	499	499
Great Lakes Gas Transmission Limited Partnership	**526**	**496**	434	519
Tuscarora Gas Transmission Company	**78**	**80**	67	81
Portland Natural Gas Transmission System	**236**	**220**	205	214
Other	**22**	**24**	17	24
	16,154	**15,337**	12,933	14,420
Junior Subordinated Notes	**1,213**	**815**	975	914
	17,367	**16,152**	13,908	15,334
Long-Term Debt of Joint Ventures				
Northern Border Pipeline Company	**391**	**391**	311	329
Iroquois Gas Transmission System, L.P.	**195**	**181**	169	180
Bruce Power L.P. and Bruce Power A L.P.	**330**	**318**	243	243
Trans Québec & Maritimes Pipeline Inc.	**155**	**157**	165	169
Other	**5**	**5**	15	16
	1,076	**1,052**	903	937
	18,443	**17,204**	14,811	16,271

(1) At December 31, 2008, the carrying amount of Long-Term Debt included $15 million (2007 – $15 million) for fair value adjustments related to swap agreements on $50 million (2007 – $150 million) and US$200 million (2007 – US$200 million) of this debt.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

	2008		2007	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**1,308**	**1,308**	504	504
Accounts receivable and other assets[2][3]	**1,404**	**1,404**	1,231	1,231
Available-for-sale assets[2]	**27**	**27**	17	17
	2,739	**2,739**	1,752	1,752
Financial Liabilities[1][3]				
Notes payable	**1,702**	**1,702**	421	421
Accounts payable and deferred amounts[4]	**1,372**	**1,372**	1,193	1,193
Accrued interest	**359**	**359**	261	261
Long-term debt and junior subordinated notes	**17,367**	**16,152**	13,908	15,334
Long-term debt of joint ventures	**1,076**	**1,052**	903	937
Other long-term liabilities of joint ventures[4]	**–**	**–**	60	60
	21,876	**20,637**	16,746	18,206

(1) Consolidated Net Income in 2008 and 2007 included unrealized gains or losses of nil for the fair value adjustments to each of these financial instruments.

(2) At December 31, 2008, the Consolidated Balance Sheet included financial assets of $1,257 million (2007 – $1,018 million) in Accounts Receivable and $174 million (2007 – $230 million) in Other Assets.

(3) Recorded at amortized cost, except for certain Long-Term Debt which is adjusted to fair value.

(4) At December 31, 2008, the Consolidated Balance Sheet included financial liabilities of $1,350 million (2007 – $1,175 million) in Accounts Payable and $22 million (2007 – $78 million) in Deferred Amounts.

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments is as follows:

December 31 *(all amounts in millions unless otherwise indicated)*	2008 Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values[(1)]					
Assets	**$132**	**$144**	**$10**	**$41**	**$57**
Liabilities	**$(82)**	**$(150)**	**$(10)**	**$(55)**	**$(117)**
Notional Values					
Volumes[(2)]					
Purchases	**4,035**	**172**	**410**	**–**	**–**
Sales	**5,491**	**162**	**252**	**–**	**–**
Canadian dollars	**–**	**–**	**–**	**–**	**1,016**
U.S. dollars	**–**	**–**	**–**	**U.S. 479**	**U.S. 1,575**
Japanese yen (in billions)	**–**	**–**	**–**	**JPY 4.3**	**–**
Cross-currency	**–**	**–**	**–**	**227/U.S. 157**	**–**
Net unrealized gains/(losses) in the year[(3)]	**$24**	**$(23)**	**$1**	**$(9)**	**$(61)**
Net realized gains/(losses) in the year[(3)]	**$23**	**$(2)**	**$1**	**$6**	**$13**
Maturity dates	**2009-2014**	**2009-2011**	**2009**	**2009-2012**	**2009-2018**
Derivative Financial Instruments in Hedging Relationships[(4)(5)]					
Fair Values[(1)]					
Assets	**$115**	**$–**	**$–**	**$2**	**$8**
Liabilities	**$(160)**	**$(18)**	**$–**	**$(24)**	**$(122)**
Notional Values					
Volumes[(2)]					
Purchases	**8,926**	**9**	**–**	**–**	**–**
Sales	**13,113**	**–**	**–**	**–**	**–**
Canadian dollars	**–**	**–**	**–**	**–**	**50**
U.S. dollars	**–**	**–**	**–**	**U.S. 15**	**U.S. 1,475**
Cross-currency	**–**	**–**	**–**	**136/U.S. 100**	**–**
Net realized (losses)/gains in the year[(3)]	**$(56)**	**$15**	**$–**	**$–**	**$(10)**
Maturity dates	**2009-2014**	**2009-2011**	**–**	**2009-2013**	**2009-2019**

(1) Fair value is equal to the carrying value of these derivatives.

(2) Volumes for power, natural gas and oil products derivatives are in gigawatt hours, billion cubic feet and thousands of barrels, respectively.

(3) All power, natural gas and oil products realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

(4) All hedging relationships are designated as cash flow hedges except for interest-rate derivative financial instruments designated as fair value hedges with a fair value of $8 million. In 2008, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2008, Net Income included losses of $6 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2008, there were no gains or losses included in Net Income for discontinued cash flow hedges.

The anticipated timing of settlement of the derivative contracts assumes no changes in commodity prices, interest rates and foreign exchange rates from December 31, 2008. Actual settlements will vary based on changes in these factors. The anticipated timing of settlement of these contracts is as follows:

(millions of dollars)	Total	2009	2010 and 2011	2012 and 2013	2014 and Thereafter
Derivative financial instruments held for trading	(30)	38	(46)	(14)	(8)
Derivative financial instruments in hedging relationships	(199)	(68)	(65)	(43)	(23)
	(229)	(30)	(111)	(57)	(31)

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments is as follows:

	2007			
December 31 *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading				
Fair Values[1]				
Assets	$55	$43	$11	$23
Liabilities	$(44)	$(19)	$(79)	$(18)
Notional Values				
Volumes[2]				
Purchases	3,774	47	–	–
Sales	4,469	64	–	–
Canadian dollars	–	–	–	615
U.S. dollars	–	–	U.S. 484	U.S. 550
Japanese yen (in billions)	–	–	JPY 9.7	–
Cross-currency	–	–	227/U.S. 157	–
Net unrealized gains/(losses) in the year[3]	$16	$(10)	$8	$(5)
Net realized(losses)/gains in the year[3]	$(8)	$47	$39	$5
Maturity dates	2008-2016	2008-2010	2008-2012	2008-2016
Derivative Financial Instruments in Hedging Relationships[4][5]				
Fair Values[1]				
Assets	$135	$19	$–	$2
Liabilities	$(104)	$(7)	$(62)	$(16)
Notional Values				
Volumes[2]				
Purchases	7,362	28	–	–
Sales	16,367	4	–	–
Canadian dollars	–	–	–	150
U.S. dollars	–	–	U.S. 113	U.S. 875
Cross-currency	–	–	136/U.S. 100	–
Net realized (losses)/gains in the year[3]	$(29)	$18	$–	$3
Maturity dates	2008-2013	2008-2010	2008-2013	2008-2013

(1) Fair value is equal to the carrying value of these derivatives.

(2) Volumes for power and natural gas derivatives are in gigawatt hours and billion cubic feet, respectively.

(3) All power and natural gas realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

(4) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $2 million. In 2007, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2007, Net Income included gains of $7 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2007, Net Income included a loss of $4 million for the changes in fair value of an interest-rate cash flow hedge that was reclassified as a result of discontinuance of cash flow hedge accounting when the anticipated transaction was not likely to occur by the end of the originally specified time period.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 (millions of dollars)	**2008**	2007
Current		
Other current assets	**318**	160
Accounts payable	**(298)**	(144)
Long-term		
Other assets	**191**	204
Deferred amounts	**(694)**	(205)

Derivative Financial Instruments of Joint Ventures

Included in the Balance Sheet Presentation of Derivative Financial Instruments table above are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power sales derivatives was $75 million at December 31, 2008 (2007 – $75 million). These contracts mature from 2009 to 2014. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 7,600 gigawatt hours (GWh) at December 31, 2008 (2007 – 7,300 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 47 GWh at December 31, 2008 (2007 – 50 GWh).

NOTE 18 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Current			
Canada	**383**	367	264
Foreign	**143**	65	37
	526	432	301
Future			
Canada	**(1)**	12	104
Foreign	**77**	46	71
	76	58	175
	602	490	476

Geographic Components of Income

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Canada	**1,234**	1,228	1,161
Foreign	**938**	582	444
Income from continuing operations before income taxes and non-controlling interests	**2,172**	1,810	1,605

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2008**	2007	2006
Income from continuing operations before income taxes and non-controlling interests	**2,172**	1,810	1,605
Federal and provincial statutory tax rate	**29.5%**	32.1%	32.5%
Expected income tax expense	**641**	581	522
Income tax differential related to regulated operations	**44**	69	72
Lower effective foreign tax rates	**(5)**	(39)	n/a
Tax rate and legislated changes	**–**	(72)	(33)
Income from equity investments and non-controlling interests	**(45)**	(34)	(27)
Change in valuation allowance	**(9)**	–	–
Other(1)	**(24)**	(15)	(58)
Actual income tax expense	**602**	490	476

(1) Includes net income tax benefits of $5 million recorded in 2008 ($2007 – $13 million; 2006 – $51 million) on the resolution of certain income tax matters with taxation authorities and changes in estimates.

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	**2008**	2007
Deferred amounts	**119**	43
Other post-employment benefits	**69**	57
Unrealized losses on derivatives	**62**	22
Unrealized foreign exchange losses on long-term debt	**77**	n/a
Non-capital loss carryforwards	**24**	n/a
Other	**137**	77
	488	199
Less: valuation allowance(1)	**77**	13
Future income tax assets, net of valuation allowance	**411**	186
Difference in accounting and tax bases of plant, equipment and PPAs	**1,464**	1,073
Investments in subsidiaries and partnerships	**28**	61
Pension benefits	**55**	50
Unrealized foreign exchange gains on long-term debt	**14**	110
Unrealized gains on derivatives	**19**	27
Other	**54**	44
Future income tax liabilities	**1,634**	1,365
Net future income tax liabilities	**1,223**	1,179

(1) A valuation allowance was recorded in 2008 as there is no virtual certainty that the Company will realize the tax benefit related to the unrealized foreign exchange losses on long-term debt in the future.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Future income tax liabilities would have increased by approximately $102 million at December 31, 2008 (2007 – $72 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $491 million were made during the year ended December 31, 2008 (2007 – $442 million; 2006 – $494 million).

NOTE 19 NOTES PAYABLE

	2008		2007	
	Outstanding December 31	**Weighted Average Interest Rate Per Annum at December 31**	Outstanding December 31	Weighted Average Interest Rate Per Annum at December 31
	(millions of dollars)		(millions of dollars)	
Canadian dollars	**1,250**	**1.8%**	55	5.0%
U.S. dollars (2008 – US$369; 2007 – US$370)	**452**	**3.3%**	366	5.5%
	1,702		421	

Notes payable consists of commercial paper outstanding and drawings on bridge and line-of-credit facilities. Unsecured revolving and demand credit facilities totaled $4.2 billion at December 31, 2008 to support the Company's commercial paper program and for general corporate purposes. These credit facilities included the following:

- a $2.0 billion committed, syndicated, revolving credit facility maturing December 2012, which was fully available at December 31, 2008. The cost to maintain the credit facility was $2 million in 2008 (2007 – $2 million).
- a US$300 million syndicated, revolving facility, maturing February 2013, which was fully available at December 31, 2008. This facility is part of the US$1.0 billion committed, unsecured TransCanada PipeLine USA Ltd. credit facility established in February 2007.
- a US$1.0 billion committed, extendible, expandable, revolving, unsecured, one-year agreement executed by TransCanada Keystone Pipeline L.P. in fourth quarter 2008 with a syndicate of banks, bearing interest at a floating rate, based on the greater of bank prime interest rates and LIBOR, plus a margin of not less than one per cent and not more than three per cent on revolving loans and not less than three per cent and not more than 6.5 per cent if drawn as a term loan. The agreement is extendible at the option of the Keystone partnership for an additional one-year term. As at December 31, 2008, this facility was fully available. This US$1.0 billion agreement is guaranteed by TransCanada.
- demand lines totaling $611 million, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately $433 million of its total lines of credit for letters of credit at December 31, 2008. When drawn, interest on the lines of credit is charged at prime rates of Canadian chartered and U.S. banks, and at other negotiated financial bases.

In June 2008, TransCanada executed an agreement with a syndicate of banks for a US$1.5 billion, committed, unsecured, one-year bridge loan facility, at a floating interest rate based on LIBOR plus 30 basis points. The facility is extendible at the option of the Company for an additional six-month term at LIBOR plus 35 basis points. In August 2008, the Company used US$255 million from this facility and cancelled the remainder of the commitment. At December 31, 2008, US$255 million remained outstanding on the facility.

In February 2007, the Company established a US$2.2 billion committed, unsecured one-year bridge facility and utilized $1.5 billion and US$700 million to partially finance the acquisition of ANR and an increased ownership in Great Lakes. The facility had a floating interest rate based on the one-month LIBOR plus 25 basis points. The outstanding balance at December 31, 2007 of US$370 million was repaid on January 7, 2008. The undrawn balance of this facility has been cancelled and is no longer available to the Company.

NOTE 20 ASSET RETIREMENT OBLIGATIONS

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the regulated and non-regulated operations in the Pipelines segment were $69 million at December 31, 2008 (2007 – $65 million), calculated using an inflation rate ranging from two per cent to four per cent per annum. The estimated fair value of these liabilities was $31 million at December 31, 2008 (2007 – $25 million) after discounting the estimated cash flows at rates ranging from 5.4 per cent to 8.0 per cent. At December 31, 2008, the expected timing of payment for settlement of the obligations ranged from one year to 27 years. Management believes it is reasonable to assume that all retirement costs associated with its regulated pipelines will be recovered through future tolls and, therefore, typically only records asset retirement obligations for its non-regulated pipelines.

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the Energy segment were $427 million at December 31, 2008 (2007 – $216 million), calculated using an inflation rate ranging from two per cent to three per cent per annum. The estimated fair value of this liability was $85 million at December 31, 2008 (2007 – $63 million), after discounting the estimated cash flows at rates ranging from 5.4 per cent to 8.0 per cent. At December 31, 2008, the expected timing of payment for settlement of the obligations ranged from 10 years to 33 years.

Reconciliation of Asset Retirement Obligations[(1)]

(millions of dollars)	Pipelines	Energy	Total
Balance at January 1, 2006	4	29	33
New obligations and revisions in estimated cash flows	4	6	10
Accretion expense	1	1	2
Balance at December 31, 2006	9	36	45
New obligations and revisions in estimated cash flows	14	25	39
Accretion expense	2	2	4
Balance at December 31, 2007	25	63	88
New obligations and revisions in estimated cash flows	**4**	**18**	**22**
Accretion expense	**2**	**4**	**6**
Balance at December 31, 2008	**31**	**85**	**116**

(1) At December 31, 2008, Asset Retirement Obligations totalling $114 million (2007 – $88 million) and $2 million (2007 – nil) were included in Deferred Amounts and Accounts Payable, respectively.

NOTE 21 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover substantially all employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment, and increase annually in the Canadian pension plan by a portion of the increase in the Consumer Price Index (CPI). Past service costs are amortized over the expected average remaining service life of employees, which is approximately nine years.

Effective January 1, 2008, the Company also provides its employees with a Savings Plan in Canada, a 401(k) Plan in the U.S. and post-employment benefits other than pensions, including termination benefits and defined life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which was approximately 11 years at December 31, 2008. Contributions to the Savings Plan and 401(k) Plan are expensed as incurred.

Total cash payments for employee future benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was $90 million in 2008 (2007 – $61 million; 2006 – $104 million), including $21 million in 2008 (2007 – $8 million; 2006 – $2 million) related to retirement savings plans.

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2009, and the next required valuation will be as at January 1, 2010.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2008**	2007	**2008**	2007
Change in Benefit Obligation				
Benefit obligation – beginning of year	**1,462**	1,378	**155**	132
Current service cost	**52**	45	**2**	2
Interest cost	**80**	73	**8**	7
Employee contributions	**3**	4	**1**	–
Benefits paid	**(68)**	(65)	**(8)**	(7)
Actuarial (gain)/loss	**(261)**	(22)	**(21)**	8
Foreign exchange rate changes	**35**	(16)	**10**	(6)
Plan amendment	**–**	–	**(11)**	–
Acquisition	**29**	65	**8**	19
Benefit obligation – end of year	**1,332**	1,462	**144**	155
Change in Plan Assets				
Plan assets at fair value – beginning of year	**1,358**	1,264	**30**	33
Actual return on plan assets	**(222)**	33	**(10)**	2
Employer contributions	**62**	46	**7**	7
Employee contributions	**3**	4	**1**	–
Benefits paid	**(68)**	(65)	**(8)**	(7)
Foreign exchange rate changes	**32**	(17)	**6**	(5)
Acquisition	**28**	93	**–**	–
Plan assets at fair value – end of year	**1,193**	1,358	**26**	30
Funded status – plan deficit	**(139)**	(104)	**(118)**	(125)
Unamortized net actuarial loss	**340**	299	**33**	44
Unamortized past service costs	**25**	28	**(1)**	7
Accrued benefit asset/(liability), net of valuation allowance of nil	**226**	223	**(86)**	(74)

The accrued benefit asset/(liability) net of valuation allowance of nil in the Company's balance sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2008**	2007	**2008**	2007
Other Assets	**226**	223	**–**	5
Deferred Amounts	**–**	–	**(86)**	(79)
Total	**226**	223	**(86)**	(74)

Included in the above benefit obligation and fair value of plan assets at December 31 were the following amounts for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2008**	2007	**2008**	2007
Benefit obligation	**(1,317)**	(1,324)	**(144)**	(155)
Plan assets at fair value	**1,178**	1,198	**26**	30
Funded status – plan deficit	**(139)**	(126)	**(118)**	(125)

The Company's expected contributions in 2009 are approximately $140 million for the pension benefit plans and approximately $27 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2009	77	8
2010	81	9
2011	84	9
2012	88	10
2013	91	10
2014 to 2018	510	59

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations at December 31 were as follows:

	Pension Benefit Plans		Other Benefit Plans	
	2008	2007	**2008**	2007
Discount rate	**6.65%**	5.30%	**6.50%**	5.50%
Rate of compensation increase	**3.65%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan cost for years ended December 31 were as follows:

	Pension Benefit Plans			Other Benefit Plans		
	2008	2007	2006	**2008**	2007	2006
Discount rate	**5.30%**	5.05%	5.00%	**5.50%**	5.20%	5.15%
Expected long-term rate of return on plan assets	**6.95%**	6.90%	6.90%	**7.75%**	7.75%	7.75%
Rate of compensation increase	**3.60%**	3.50%	3.50%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high quality bonds that match the timing and benefits expected to be paid under each plan.

A nine per cent annual rate of increase in the per-capita cost of covered health care benefits was assumed for 2009 measurement purposes. The rate was assumed to decrease gradually to five per cent in 2018 and remain at this level thereafter. A one percentage point change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-employment benefit obligation	11	(10)

The Company's net benefit cost is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2008**	2007	2006	**2008**	2007	2006
Current service cost	**52**	45	39	**2**	2	3
Interest cost	**80**	73	65	**8**	7	8
Actual return on plan assets	**222**	(33)	(134)	**10**	(2)	(6)
Actuarial (gain)/loss	**(261)**	(22)	53	**(21)**	8	(2)
Plan amendment	**–**	–	–	**(11)**	–	(18)
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**93**	63	23	**(12)**	15	(15)
Difference between expected and actual return on plan assets	**(316)**	(51)	63	**(12)**	(1)	4
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**280**	47	(27)	**23**	(7)	4
Difference between amortization of past service costs and actual plan amendments	**4**	4	4	**11**	–	19
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Net benefit cost recognized	**61**	63	63	**12**	9	14

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

December 31	Percentage of Plan Assets		**Target Allocations**
Asset Category	**2008**	2007	**2008**
Debt securities	**48%**	42%	**35% to 60%**
Equity securities	**52%**	58%	**40% to 65%**
	100%	100%	

Debt securities included the Company's debt of $3 million (0.3 per cent of total plan assets) and $4 million (0.3 per cent of total plan assets) at December 31, 2008 and 2007, respectively. Equity securities included the Company's common shares of $4 million (0.3 per cent of total plan assets) and $6 million (0.4 per cent of total plan assets) at December 31, 2008 and 2007, respectively.

The assets of the pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

Employee Future Benefits of Joint Ventures

Certain of the Company's joint ventures sponsor DB Plans as well as post-employment benefits other than pensions, including defined life insurance and medical benefits beyond those provided by government-sponsored plans. The obligations of these plans are non-recourse to TransCanada. The following amounts in this note, including those in the accompanying tables, represent TransCanada's proportionate share with respect to these plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was $42 million in 2008 (2007 – $34 million; 2006 – $25 million).

The Company's joint ventures measure the benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuations of the pension plans for funding purposes were as at January 1, 2009, and the next required valuations will be as at January 1, 2010.

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2008**	2007	**2008**	2007
Change in Benefit Obligation				
Benefit obligation – beginning of year	**789**	807	**165**	169
Current service cost	**27**	28	**8**	10
Interest cost	**42**	40	**9**	8
Employee contributions	**6**	5	**–**	–
Benefits paid	**(37)**	(23)	**(4)**	(2)
Actuarial gain	**(229)**	(34)	**(45)**	(16)
Foreign exchange rate changes	**1**	(3)	**–**	–
Acquisition	**–**	(31)	**–**	(2)
Plan amendment	**–**	–	**–**	(2)
Benefit obligation – end of year	**599**	789	**133**	165
Change in Plan Assets				
Plan assets at fair value – beginning of year	**626**	666	**–**	–
Actual return on plan assets	**(78)**	(1)	**–**	–
Employer contributions	**38**	32	**4**	2
Employee contributions	**6**	5	**–**	–
Benefits paid	**(37)**	(23)	**(4)**	(2)
Foreign exchange rate changes	**1**	(5)	**–**	–
Acquisition	**–**	(48)	**–**	–
Plan assets at fair value – end of year	**556**	626	**–**	–
Funded status – plan deficit	**(43)**	(163)	**(133)**	(165)
Unamortized net actuarial loss/(gain)	**51**	169	**(3)**	45
Unamortized past service costs	**–**	–	**3**	3
Accrued benefit asset/(liability), net of valuation allowance of nil	**8**	6	**(133)**	(117)

The accrued benefit asset/(liability), net of valuation allowance of nil in the Company's balance sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2008**	2007	**2008**	2007
Other Assets	**8**	6	**–**	–
Deferred Amounts	**–**	–	**(133)**	(117)
Total	**8**	6	**(133)**	(117)

The following amounts were included at December 31 in the above benefit obligation and fair value of plan assets for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
(millions of dollars)	**2008**	2007	**2008**	2007
Benefit obligation	**(594)**	(786)	**(133)**	(165)
Plan assets at fair value	**551**	623	**–**	–
Funded status – plan deficit	**(43)**	(163)	**(133)**	(165)

The expected total contributions of the Company's joint ventures in 2009 are approximately $37 million for the pension benefit plans and approximately $4 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2009	39	4
2010	43	5
2011	46	6
2012	50	7
2013	54	7
2014 to 2018	325	49

The significant weighted average actuarial assumptions adopted in measuring the benefit obligations of the Company's joint ventures at December 31 were as follows:

	Pension Benefit Plans		Other Benefit Plans	
	2008	2007	**2008**	2007
Discount rate	**6.70%**	5.25%	**6.40%**	5.15%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the net benefit plan costs of the Company's joint ventures for years ended December 31 were as follows:

	Pension Benefit Plans			Other Benefit Plans		
	2008	2007	2006	**2008**	2007	2006
Discount rate	**5.25%**	5.00%	5.25%	**5.15%**	4.90%	5.15%
Expected long-term rate of return on plan assets	**7.00%**	7.00%	7.30%			
Rate of compensation increase	**3.50%**	3.50%	3.50%			

A one percentage point change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	3	(2)
Effect on post-employment benefit obligation	17	(14)

The Company's proportionate share of net benefit cost of joint ventures is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2008**	2007	2006	**2008**	2007	2006
Current service cost	**27**	28	24	**8**	10	7
Interest cost	**42**	40	37	**9**	8	5
Actual return on plan assets	**78**	1	(68)	**–**	–	–
Actuarial (gain)/loss	**(229)**	(34)	77	**(45)**	(16)	72
Plan amendment	**–**	–	–	**–**	(2)	6
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**(82)**	35	70	**(28)**	–	90
Difference between expected and actual return on plan assets	**(122)**	(44)	26	**–**	–	–
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**239**	44	(70)	**48**	20	(72)
Difference between amortization of past service costs and actual plan amendments	**–**	–	–	**–**	3	(6)
Net benefit cost recognized related to joint ventures	**35**	35	26	**20**	23	12

The weighted average asset allocations and target allocations by asset category in the pension plans of the Company's joint ventures were as follows:

December 31	Percentage of Plan Assets		Target Allocations
Asset Category	**2008**	2007	**2008**
Debt securities	**44%**	43%	**40%**
Equity securities	**56%**	57%	**60%**
	100%	100%	

Debt securities included the Company's debt of $1 million (0.2 per cent of total plan assets) and $1 million (0.2 per cent of total plan assets) at December 31, 2008 and 2007, respectively. Equity securities included the Company's common shares of $3 million (0.6 per cent of total plan assets) and $3 million (0.5 per cent of total plan assets) at December 31, 2008 and 2007, respectively.

The assets of the pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

NOTE 22 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2008**	2007	2006
(Increase)/decrease in accounts receivable	**(197)**	51	(188)
Decrease/(increase) in inventories	**82**	(6)	(108)
(Increase)/decrease in other current assets	**(146)**	118	(6)
(Decrease)/increase in accounts payable	**(18)**	61	(42)
Increase/(decrease) in accrued interest	**98**	(9)	41
	(181)	215	(303)

NOTE 23 COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating leases
Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services and equipment are approximately as follows:

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-leases	Net Payments
2009	40	(12)	28
2010	39	(12)	27
2011	39	(10)	29
2012	38	(5)	33
2013	37	(4)	33
2014 and thereafter	260	(7)	253
Total	453	(50)	403

The operating lease agreements for premises, services and equipment expire at various dates through 2035, with an option to renew certain lease agreements for periods of one year to ten years. Net rental expense on operating leases in 2008 was $52 million (2007 – $34 million; 2006 – $25 million).

TransCanada's commitments under the acquired Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from the above table, as these payments are dependent upon plant availability, among other factors. The amount of power purchased under the PPAs in 2008 was $471 million (2007 – $440 million; 2006 – $499 million). The generating capacities and expiry dates of the PPAs are as follows:

	Megawatts	Expiry Date
Sundance A	560	December 31, 2017
Sundance B	353	December 31, 2020
Sheerness	756	December 31, 2020

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Bruce Power

Bruce A has signed commitments to third-party suppliers related to refurbishing and restarting Units 1 and 2 and refurbishing Units 3 and 4 to extend their operating life. TransCanada's share of these signed commitments, which extend over the three-year period ending December 31, 2011, are as follows:

Year ended December 31 (millions of dollars)	
2009	204
2010	49
2011	2
	255

Loan-Aboriginal Pipeline Group

On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement governing TransCanada's role in the Mackenzie Gas Pipeline (MGP) project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project pre-development costs. These costs, on a cumulative basis, are currently forecast to be between $150 million and $200 million, depending upon the pace of project development. As at December 31, 2008, the Company had advanced $140 million to the APG.

TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. Detailed discussions with the Canadian government are continuing, and project timing continues to be uncertain. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project, including a review by TransCanada of the carrying value of advances to the APG.

Other Commitments

TransCanada is committed to capital expenditures totalling approximately $2.3 billion related to its share of the construction costs of Keystone, North Central Corridor and other pipeline projects.

The Company is committed to capital expenditures totalling approximately $1.0 billion related to its share of the construction costs of Coolidge, Bruce Power, the remaining Cartier Wind projects, Halton Hills and Portlands Energy.

Contingencies

On April 3, 2008, the Ontario Court of Appeal dismissed an appeal filed by the Canadian Alliance of Pipeline Landowners' Associations (CAPLA). CAPLA filed the appeal as a result of a decision by the Ontario Superior Court in November 2006 to dismiss CAPLA's class action lawsuit against TransCanada and Enbridge Inc. for damages alleged to have arisen from the creation of a control zone within 30 metres of a pipeline pursuant to Section 112 of the *National Energy Board Act*. The Ontario Court of Appeal's decision is final and binding as CAPLA did not seek any further appeal within the time frame allowed.

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2008, the Company accrued approximately $83 million related to operating facilities and $3 million related to discontinued operation sites. The accrued amount represents the Company's estimate of the amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TransCanada, Cameco Corporation and BPC Generation Infrastructure Trust (BPC) have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, a lease agreement and contractor services. The guarantees have terms ranging from one year ending in 2010 to perpetuity. In addition, TransCanada and BPC have severally guaranteed one-half of certain contingent financial obligations related to an agreement with the Ontario Power Authority to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated at December 31, 2008 to range from $711 million to a maximum of $750 million. The fair value of these guarantees is estimated to be $17 million.

The Company and its partners in certain jointly owned entities have severally as well as jointly and severally guaranteed the financial performance of these entities related primarily to construction projects, redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these guarantees was estimated at December 31, 2008 to range from $688 million to a maximum of $1.4 billion. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners. Deferred Amounts includes $9 million for the fair value of these joint and several guarantees.

TransCanada has guaranteed a subsidiary's equity undertaking to support the payment, under certain conditions, of principal and interest on US$43 million of the public debt obligations of TransGas de Occidente S.A. (TransGas). The Company has a 46.5 per cent interest in TransGas. Under the terms of a shareholder agreement, TransCanada and another major multinational company may be required to severally fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement would convert into share capital of TransGas. The Company's potential exposure is contingent on the impact any change of law would have on the ability of TransGas to service the debt. There has been no change in applicable law since the issuance of debt in 1995 and, thus, no exposure for TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

NOTE 24 DISCONTINUED OPERATIONS

The $28 million income from discontinued operations in 2006 reflected settlements received from bankruptcy claims related to TransCanada's Gas Marketing business, which was sold in 2001.

SUPPLEMENTARY INFORMATION

SELECTED QUARTERLY AND ANNUAL CONSOLIDATED FINANCIAL DATA

Toronto Stock Exchange *(Stock trading symbol TRP)*	First	Second	Third	Fourth	Annual
2008 (Canadian dollars)					
High	**40.97**	**40.71**	**40.65**	**39.26**	**40.97**
Low	**36.21**	**35.98**	**35.95**	**29.42**	**29.42**
Close	**39.55**	**39.50**	**38.17**	**33.17**	**33.17**
Volume (millions of shares)	**86.1**	**134.0**	**114.0**	**159.7**	**493.8**
2007 (Canadian dollars)					
High	41.35	40.29	39.83	40.73	41.35
Low	36.75	35.77	35.43	36.47	35.43
Close	38.35	36.64	36.47	40.54	40.54
Volume (millions of shares)	88.7	78.7	91.4	77.2	336.0
2006 (Canadian dollars)					
High	37.15	34.93	36.49	40.90	40.90
Low	33.60	30.77	31.70	33.87	30.77
Close	33.67	31.85	35.15	40.61	40.61
Volume (millions of shares)	71.9	74.1	61.6	61.0	268.6

New York Stock Exchange *(Stock trading symbol TRP)*					
2008 (U.S. dollars)					
High	**41.53**	**40.64**	**39.29**	**36.33**	**41.53**
Low	**35.60**	**35.33**	**34.01**	**23.52**	**23.52**
Close	**38.53**	**38.77**	**36.15**	**27.14**	**27.14**
Volume (millions of shares)	**8.7**	**8.8**	**9.8**	**17.2**	**44.5**
2007 (U.S. dollars)					
High	35.30	37.21	38.06	43.94	43.94
Low	31.33	32.91	32.92	36.68	31.33
Close	33.28	34.41	36.61	40.93	40.93
Volume (millions of shares)	8.2	5.7	9.0	7.9	30.8
2006 (U.S. dollars)					
High	32.14	31.36	32.85	35.40	35.40
Low	28.66	27.40	28.23	29.82	27.40
Close	28.93	28.68	31.44	34.95	34.95
Volume (millions of shares)	5.8	9.0	5.6	7.3	27.7

NINE-YEAR FINANCIAL HIGHLIGHTS

(millions of dollars except where indicated)	**2008**	2007	2006	2005	2004	2003	2002	2001	2000
Income Statement									
Revenues	**8,619**	8,828	7,520	6,124	5,497	5,636	5,225	5,285	4,384
Net income from continuing operations	**1,440**	1,223	1,051	1,209	980	801	747	686	628
Net income/(loss) by segment									
Pipelines	**902**	686	560	679	584	625	639	572	613
Energy	**614**	514	452	566	398	217	160	181	95
Corporate	**(76)**	23	39	(36)	(2)	(41)	(52)	(67)	(80)
Continuing operations	**1,440**	1,223	1,051	1,209	980	801	747	686	628
Discontinued operations	**–**	–	28	–	52	50	–	(67)	61
Net income	**1,440**	1,223	1,079	1,209	1,032	851	747	619	689
Cash Flow Statement									
Funds generated from operations	**3,021**	2,621	2,378	1,951	1,703	1,822	1,843	1,625	1,484
(Increase)/decrease in operating working capital	**(181)**	215	(303)	(49)	29	93	92	(487)	437
Net cash provided by operations	**2,840**	2,836	2,075	1,902	1,732	1,915	1,935	1,138	1,921
Capital expenditures and acquisitions	**6,363**	5,874	2,042	2,071	2,046	965	851	1,082	1,144
Disposition of assets, net of current income taxes	**28**	35	23	671	410	–	–	1,170	2,233
Cash dividends paid on common shares	**577**	546	617	586	552	510	466	418	423
Balance Sheet									
Assets									
Plant, property and equipment									
Pipelines	**20,700**	18,280	17,141	16,528	17,306	16,064	16,158	16,562	16,937
Energy	**8,435**	5,127	4,302	3,483	1,421	1,368	1,340	1,116	776
Corporate	**54**	45	44	27	37	50	64	66	111
Total assets									
Continuing operations	**39,414**	30,330	25,909	24,113	22,415	20,876	20,416	20,255	20,238
Discontinued operations	**–**	–	–	–	7	11	139	276	5,007
Total assets	**39,414**	30,330	25,909	24,113	22,422	20,887	20,555	20,531	25,245
Capitalization									
Long-term debt	**15,368**	12,377	10,887	9,640	9,749	9,516	8,899	9,444	10,008
Junior subordinated notes	**1,213**	975	–	–	–	–	–	–	–
Preferred securities	**–**	–	536	536	554	598	944	950	1,208
Non-controlling interests	**1,194**	999	755	783	700	713	677	675	646
Common shareholders’ equity	**12,898**	9,785	7,701	7,206	6,565	6,091	5,747	5,426	5,211

	2008	2007	2006	2005	2004	2003	2002	2001	2000
Per Common Share Data (dollars)									
Net income – Basic									
Continuing operations	**$2.53**	$2.31	$2.15	$2.49	$2.02	$1.66	$1.56	$1.44	$1.32
Discontinued operations	**–**	–	0.06	–	0.11	0.10	–	(0.14)	0.13
	$2.53	$2.31	$2.21	$2.49	$2.13	$1.76	$1.56	$1.30	$1.45
Net income – Diluted									
Continuing operations	**$2.52**	$2.30	$2.14	$2.47	$2.01	$1.66	$1.55	$1.44	$1.32
Discontinued operations	**–**	–	0.06	–	0.11	0.10	–	(0.14)	0.13
	$2.52	$2.30	$2.20	$2.47	$2.12	$1.76	$1.55	$1.30	$1.45
Dividends declared	**$1.44**	$1.36	$1.28	$1.22	$1.16	$1.08	$1.00	$0.90	$0.80
Book value(1)(6)	**$20.92**	$18.13	$15.75	$14.79	$13.54	$12.61	$11.99	$11.38	$10.97
Market price									
Toronto Stock Exchange ($Cdn)									
High	**40.97**	41.35	40.90	37.90	30.35	28.49	23.91	21.13	17.25
Low	**29.42**	35.43	30.77	28.94	25.37	20.77	19.05	14.85	9.80
Close	**33.17**	40.54	40.61	36.65	29.80	27.88	22.92	19.87	17.20
Volume (millions of shares)	**493.8**	336.0	268.6	238.0	280.1	277.9	280.6	288.2	400.7
New York Stock Exchange ($US)									
High	**41.53**	43.94	35.40	32.41	24.91	21.88	15.56	13.41	11.50
Low	**23.52**	31.33	27.40	23.36	18.75	14.16	11.89	9.88	6.75
Close	**27.14**	40.93	34.95	31.48	24.87	21.51	14.51	12.51	11.50
Volume (millions of shares)	**44.5**	30.8	27.7	31.6	33.0	21.2	16.3	16.8	21.2
Shares outstanding (millions)									
Average for the year	**569.6**	529.9	488.0	486.2	484.1	481.5	478.3	475.8	474.6
End of year	**616.5**	539.8	489.0	487.2	484.9	483.2	479.5	476.6	474.9
Registered common shareholders(1)	**33,681**	34,204	35,522	30,533	31,837	33,133	34,902	36,350	30,758
Financial Ratios									
Return on average common shareholders' equity(2)	**12.7%**	14.0%	14.5%	17.6%	16.3%	14.4%	13.4%	11.6%	13.6%
Dividend yield(3)	**4.3%**	3.4%	3.2%	3.3%	3.9%	3.9%	4.4%	4.5%	4.7%
Price/earnings multiple(4)(5)	**13.1**	17.5	18.4	14.7	14.0	15.8	14.7	15.3	11.9
Price/book multiple(4)(6)	**1.6**	2.2	2.6	2.5	2.2	2.2	1.9	1.7	1.6
Debt to debt plus shareholders' equity(7)	**57%**	59%	61%	59%	63%	64%	64%	67%	69%
Total shareholder return(8)	**(15%)**	3%	15%	28%	11%	27%	21%	21%	48%
Earnings to fixed charges(9)	**2.7**	2.6	2.5	2.9	2.5	2.3	2.3	2.1	1.9

(1) As at December 31.

(2) The return on average common shareholders' equity is determined by dividing net income by average common shareholders' equity (i.e. opening plus closing shareholders' equity divided by two) for each year.

(3) The dividend yield is determined by dividing dividends declared during the year by price per share as at December 31.

(4) Price per share refers to market price per share as reported on the Toronto Stock Exchange as at December 31.

(5) The price/earnings multiple is determined by dividing price per share by the basic net income per share.

(6) The price/book multiple is determined by dividing price per share by book value per share as calculated by dividing shareholders' equity by the number of shares outstanding as at December 31.

(7) Debt comprises total long-term debt, including the current portion of long-term debt, plus preferred securities as at December 31, and excludes non-recourse debt of joint ventures. Shareholders' equity in this ratio is at December 31.

(8) Total shareholder return is the sum of the change in price per share, the dividends received and the impact of dividend re-investment in a calendar year, expressed as a percentage of the value of shares at the end of the previous year.

(9) The earnings to fixed charges ratio is determined by dividing earnings by fixed charges. Earnings is calculated as the sum of income from continuing operations, financial charges, financial charges of joint ventures, income taxes, income from non-controlling interests (excluding non-controlling interests with financial charges) and adjusted for undistributed earnings of investments accounted for by the equity method. Fixed charges is calculated as the sum of financial charges, financial charges of joint ventures and capitalized interest.

INVESTOR INFORMATION

STOCK EXCHANGES, SECURITIES AND SYMBOLS

TransCanada Corporation
Common shares are listed on the Toronto and New York stock exchanges under the symbol: TRP

TransCanada PipeLines Limited (TCPL)*
Preferred shares are listed on the Toronto Stock Exchange under the following symbols:

Cumulative redeemable first preferred Series U: TCA.PR.X and Series Y: TCA.PR.Y

* TCPL is a wholly owned subsidiary of TransCanada Corporation.

Annual Meeting The annual meeting of shareholders is scheduled for May 1, 2009 at 10:00 a.m. (Mountain Daylight Time) at the Roundup Centre, Calgary, Alberta.

Dividend Payment Dates Scheduled common share dividend payment dates in 2009 are January 30, April 30, July 31 and October 30.

Dividend Reinvestment and Share Purchase Plan TransCanada's dividend reinvestment and share purchase plan (Plan) allows common shareholders of TransCanada and preferred shareholders of TCPL to purchase additional common shares by reinvesting their cash dividends without incurring brokerage or administrative fees. Participants in the Plan may also buy additional common shares, up to $10,000 (US$7,000) per quarter. Please contact our Plan agent, Computershare Trust Company of Canada, for more information on the Plan or visit us at www.transcanada.com.

TRANSFER AGENTS, REGISTRARS AND TRUSTEE

TransCanada Corporation Common Shares Computershare Trust Company of Canada (Montréal, Toronto, Calgary and Vancouver) and Computershare Trust Company, N.A. (Golden)

TCPL Preferred Shares Computershare Trust Company of Canada (Montréal, Toronto, Calgary and Vancouver)

TCPL Debentures

Canadian Series: CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Calgary and Vancouver)

11.10% series N	10.50% series O	10.50% series P	10.625% series Q	
11.85% series R	11.90% series S	11.80% series U	9.80% series V	9.45% series W

U.S. Series: The Bank of New York (New York) 9.875% and 8.625%

TCPL Canadian Medium-Term Notes CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Calgary and Vancouver)

TCPL U.S. Medium-Term Notes and Senior Notes The Bank of New York (New York)

TCPL U.S. Junior Subordinated Notes The Bank of Nova Scotia Trust Company of New York

NOVA Gas Transmission Ltd. (NGTL) Debentures

Canadian Series: CIBC Mellon Trust Company (Halifax, Montreal, Toronto, Calgary and Vancouver)

11.95% series 13	11.70% series 15	11.20% series 18	12.625% series 19
12.20% series 20	12.20% series 21	9.90% series 23	

U.S. Series: U.S. Bank Trust National Association (New York) 8.50% and 7.875%

NGTL Canadian Medium-Term Notes CIBC Mellon Trust Company (Halifax, Montreal, Toronto, Calgary and Vancouver)

NGTL U.S. Medium-Term Notes U.S. Bank Trust National Association (New York)

REGULATORY FILINGS

Annual Information Form TransCanada's 2008 Annual Information Form, as filed with Canadian securities commissions and as filed under Form 40-F with the SEC, is available on our website at www.transcanada.com.

A printed copy may be obtained from:

Corporate Secretary, TransCanada Corporation, 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1

SHAREHOLDER ASSISTANCE

If you are a registered shareholder and have questions regarding your account, please contact our transfer agent in writing, by telephone or e-mail at:

Computershare Trust Company of Canada, 100 University Avenue, 9th Floor, North Tower, Toronto, Ontario, Canada M5J 2Y1

Toll-free: 1 (800) 340-5024
Telephone: 1 (514) 982-7959

E-mail: transcanada@computershare.com

www.computershare.com

If you hold your shares in a brokerage account (beneficial shareholder), questions should be directed to your broker on all administrative matters.

If you would like to receive quarterly reports, please contact Computershare or visit our website at www.transcanada.com.

Electronic Proxy Voting and Delivery of Documents TransCanada is pleased to offer registered and beneficial shareholders the ability to receive their documents (annual report, management information circular, notice of meeting and view-only proxy form) and vote online.

In 2009, registered shareholders who opt to receive their documents electronically will have a tree planted on their behalf through eTree. For more information and to sign up online, registered shareholders can visit www.etree.ca/transcanada.

Shareholders who do not have access to e-mail, or who still prefer to receive their proxy materials by mail also have the ability to choose whether to receive TransCanada's annual report by regular mail. Each year, shareholders are required to renew their option and will receive a notification for doing so. The annual report is available on the TransCanada website at www.transcanada.com/investor/financial.html at the same time that the report is mailed to shareholders.

Electronic delivery and the ability to opt out of receiving the annual report by mail, provides increased convenience to shareholders, benefits to the environment and reduced mailing and printing costs for the company.

TransCanada in the Community TransCanada's annual Corporate Social Responsibility Report is available at www.transcanada.com. If you would like to receive a copy of this report by mail, please contact:

Communications 450 1st Street SW, Calgary, Alberta T2P 5H1, 1.403.920.2000 or 1.800.861.3805 or Communications@transcanada.com

Visit our website at www.transcanada.com to access TransCanada's corporate and financial information, including quarterly reports, news releases, real-time conference call webcasts and investor presentations.

Si vous désirez vous procurer un exemplaire de ce rapport en français, veuillez consulter notre site web ou vous adresser par écrit à TransCanada Corporation, bureau du secrétaire.

BOARD OF DIRECTORS

(as at December 31, 2008)

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Calgary, Alberta

Harold N. Kvisle
President and CEO
TransCanada Corporation
Calgary, Alberta

Kevin E. Benson(1)
Corporate Director
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of Management and Director,
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University of Toronto
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E. Linn Draper(5)(7)
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Lampasas, Texas

The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C.(2)(6)
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Royal Bank of Canada
Calgary, Alberta

W. Thomas Stephens(6)(8)
Former Chairman and Chief Executive Officer
Boise Cascade, LLC
Greenwood Village, Colorado

D. Michael G. Stewart(3)
Corporate Director
Calgary, Alberta

* Non-voting member of the Governance Committee and the Human Resources Committee of the Board
(1) Chair, Audit Committee
(2) Member, Audit Committee
(3) Member, Governance Committee
(4) Chair, Governance Committee
(5) Chair, Health, Safety and Environment Committee
(6) Member, Health, Safety and Environment Committee
(7) Member, Human Resources Committee
(8) Chair, Human Resources Committee

CORPORATE GOVERNANCE

Please refer to TransCanada's Notice of 2009 Annual Meeting of Common Shareholders and Management Proxy Circular for the company's statement of corporate governance.

TransCanada's Corporate Governance Guidelines, Board charter, Committee charters, Chair and CEO terms of reference and codes of business conduct and ethics are available on our website at www.transcanada.com. Also available on our website is a summary of the significant ways in which TransCanada's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

Additional information relating to the company is filed with securities regulators in Canada on SEDAR at www.sedar.com and in the United States on EDGAR at www.sec.gov. The documents referred to in this Annual Report may be obtained free of charge by contacting TransCanada's Corporate Secretary at 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1, or by telephoning 1.800.661.3805.

Ethics Help-Line The Audit Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The Ethics Help-Line number is 1.888.920.2042.

executive officers

Hal Kvisle
President and
Chief Executive Officer

Russ Girling
President, Pipelines

Alex Pourbaix
President, Energy

Greg Lohnes
Executive Vice-President,
and Chief Financial Officer

Dennis McConaghy
Executive Vice-President,
Pipeline Strategy and Development

Sean McMaster
Executive Vice-President,
Corporate and General Counsel

Sarah Raiss
Executive Vice-President,
Corporate Services

Don Wishart
Executive Vice-President,
Operations and Engineering

contact information

Visit our website for more information on:

- **Our Pipelines and Energy businesses**
- **Projects and initiatives**
- **Corporate responsibility**
- **Corporate governance**
- **Investor services**

www.transcanada.com

TransCanada welcomes questions from shareholders and investors.

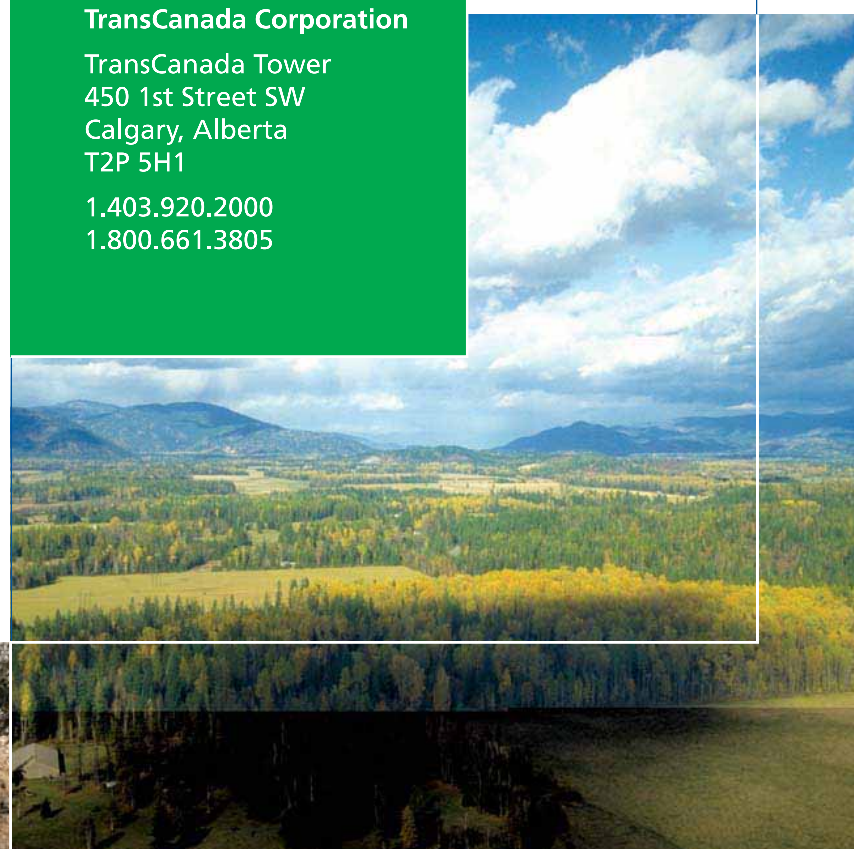
Please contact:

David Moneta, Vice-President,
Investor Relations and Corporate Communications

1.800.361.6522
(Canada and U.S. Mainland)

TransCanada Corporation
TransCanada Tower
450 1st Street SW
Calgary, Alberta
T2P 5H1

1.403.920.2000
1.800.661.3805



our vision

TransCanada will be the leading energy infrastructure company in North America, with a strong focus on pipelines and power generation opportunities located in regions where we have or can develop significant competitive advantage.

MOST SUSTAINABLE CORPORATIONS
GLOBAL 100

Dow Jones Sustainability Indexes
Member 2008/09

TransCanada
In business to deliver

Please recycle Printed in Canada March 2009

EXHIBIT S-2-C:

SOIL SUITABILITY & MAPPING

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

Soils Identified in the Sisk Mountain Wind Power Project Area

Soil map unit metadata for the project area was obtained via the USDA-NRCS Soil Survey Geographic (SSURGO) database for Somerset County Area and Parts of Franklin and Oxford Counties, Maine. A map of soils found in the project area is provided as Figure S2-C-1. Soil series descriptions for the project area were obtained from the United States Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS) *Soil Survey of Franklin County Area and Part of Somerset County, Maine (2003)*, and the USDA/NRCS website.

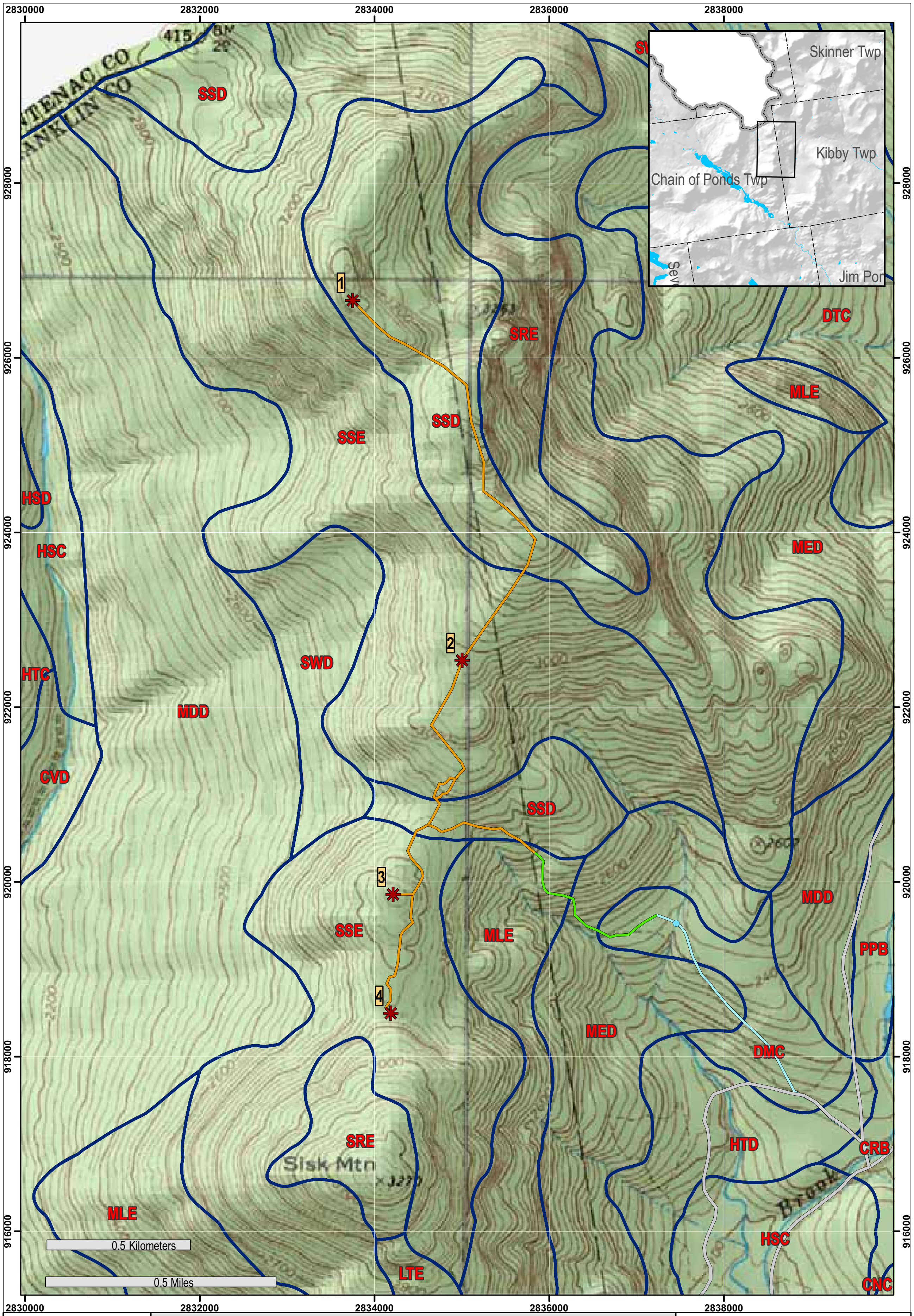
Table 1 lists the soil types associated with each proposed met tower site and its access trail. Table 2 lists the complex/series names, parent material and range of slope for each soil map unit associated with the project area. USDA/NRCS descriptions for each of the soil map units are provided in Appendix A.

Table 1: Soil Map Units Associated with Proposed Met Tower Locations and Access

Location	Map Units
Met Tower #1	SSD
Tower 1 access (from tower 2)	SSD, SSE
Met Tower #2	SSE
Tower 2 access (from junction of ridge access trail)	SSD, SSE
Met Tower #3	SSE
Tower 3 access (from junction of ridge access trail)	SSD, SSE
Met Tower #4	SSE
Tower 4 access (from tower 3)	SSE
Access from Gold Brook Road – existing maintained road portion	CRB, HTD, DMC
Access from Gold Brook Road – existing winter road portion	DMC, MED
Access from Gold Brook Road – existing skidder trail portion	DMC, MED, MLE
Access from Gold Brook Road – proposed new access trail portion	MLE, SSD

Table 2: Map Unit Complex/Series Names, Parent Material and Range of Slope

Map Unit Symbol	Complex / Series	Parent Material	Range of Slope (%)
CRB	Colonel-Pillsbury-Skerry association	Glacial till	1 – 8%
DMC	Dixfield-Colonel-Marlow association	Glacial till	3 – 15%
HTD	Hermon-Rawsonville-Skerry	Glacial till	12-30%
MED	Marlow-Dixfield-Rawsonville	Glacial till	12-30%
MLE	Marlow-Hogback-Berkshire association	Glacial till	25 – 45%
SSD	Saddleback-Sisk-Rock outcrop association	Glacial till	15 – 30%
SSE	Saddleback-Sisk-Rock outcrop association	Glacial till	20 – 45%



Potential Met Tower Sites
Stream Crossing
Maintained Road
Existing Winter Road
Existing Skid Trail
Potential New Access Trail
USDA NRCS Soil Series Boundary

Notes: Base map: 24k USGS Topographic Map. Elevation shading derived from MEDEM10 courtesy of Maine OGIS. Coordinate Grid: NAD83 UTM Zone 19N, Meters

Sisk Mountain
Surficial Soils

SUPPLEMENT: S-2C-1

249 Western Ave
Augusta, ME 04330

TRC

Created:
3/10/2009

APPENDIX A:

USDA/NRCS Map Unit Soil Descriptions

Somerset County Area and Parts of Franklin and Oxford Counties, Maine

CRB—Colonel-Pillsbury-Skerry association, 1 to 8 percent slopes

Map Unit Setting

Elevation: 350 to 2,500 feet
Mean annual precipitation: 35 to 40 inches
Frost-free period: 90 to 115 days

Map Unit Composition

Colonel and similar soils: 40 percent
Pillsbury and similar soils: 30 percent
Skerry and similar soils: 15 percent

Description of Colonel

Setting

Landform: Drumlinoid ridges
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Linear
Across-slope shape: Concave
Parent material: Coarse-loamy lodgment till derived from granite and gneiss and/or coarse-loamy lodgment till derived from mica schist

Properties and qualities

Slope: 1 to 8 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 12 to 24 inches to dense material
Drainage class: Somewhat poorly drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 7 to 17 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.3 inches)

Interpretive groups

Land capability (nonirrigated): 6s

Typical profile

0 to 3 inches: Highly decomposed plant material
3 to 5 inches: Fine sandy loam
5 to 18 inches: Fine sandy loam
18 to 65 inches: Gravelly sandy loam

Description of Pillsbury

Setting

Landform: Till plains
Down-slope shape: Concave

Across-slope shape: Concave
Parent material: Coarse-loamy lodgment till derived from mica schist

Properties and qualities

Slope: 1 to 8 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 15 to 25 inches to dense material
Drainage class: Poorly drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 0 to 18 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 3.4 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 4 inches: Muck
4 to 21 inches: Fine sandy loam
21 to 65 inches: Gravelly loam

Description of Skerry

Setting

Landform: Drumlinoid ridges
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Head slope
Down-slope shape: Linear
Across-slope shape: Concave
Parent material: Coarse-loamy lodgment till derived from mica schist and/or coarse-loamy lodgment till derived from granite and gneiss

Properties and qualities

Slope: 3 to 8 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 18 to 30 inches to dense material
Drainage class: Moderately well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 15 to 23 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 3.7 inches)

Interpretive groups

Land capability (nonirrigated): 6s

Typical profile

0 to 1 inches: Highly decomposed plant material
1 to 3 inches: Fine sandy loam
3 to 30 inches: Gravelly fine sandy loam

30 to 65 inches: Gravelly sandy loam

Data Source Information

Soil Survey Area: Somerset County Area and Parts of Franklin and Oxford Counties, Maine
Survey Area Data: Version 12, Dec 19, 2008

Somerset County Area and Parts of Franklin and Oxford Counties, Maine

DMC—Dixfield-Colonel-Marlow association, 3 to 15 percent slopes

Map Unit Setting

Elevation: 350 to 2,500 feet
Mean annual precipitation: 35 to 40 inches
Frost-free period: 90 to 115 days

Map Unit Composition

Dixfield and similar soils: 40 percent
Colonel and similar soils: 25 percent
Marlow and similar soils: 20 percent

Description of Dixfield

Setting

Landform: Drumlinoid ridges
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Talf
Down-slope shape: Linear
Across-slope shape: Convex
Parent material: Coarse-loamy lodgment till derived from mica schist

Properties and qualities

Slope: 5 to 15 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 18 to 36 inches to dense material
Drainage class: Moderately well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 16 to 29 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.3 inches)

Interpretive groups

Land capability (nonirrigated): 6s

Typical profile

0 to 2 inches: Highly decomposed plant material
2 to 3 inches: Gravelly fine sandy loam
3 to 22 inches: Fine sandy loam
22 to 65 inches: Gravelly fine sandy loam

Description of Colonel

Setting

Landform: Drumlinoid ridges
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope

Down-slope shape: Linear
Across-slope shape: Concave
Parent material: Coarse-loamy lodgment till derived from granite and gneiss and/or coarse-loamy lodgment till derived from mica schist

Properties and qualities

Slope: 3 to 10 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 12 to 24 inches to dense material
Drainage class: Somewhat poorly drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 7 to 17 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.3 inches)

Interpretive groups

Land capability (nonirrigated): 6s

Typical profile

0 to 3 inches: Highly decomposed plant material
3 to 5 inches: Fine sandy loam
5 to 18 inches: Fine sandy loam
18 to 65 inches: Gravelly sandy loam

Description of Marlow

Setting

Landform: Drumlinoid ridges
Landform position (two-dimensional): Summit
Landform position (three-dimensional): Interfluve
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy lodgment till derived from granite and/or coarse-loamy lodgment till derived from mica schist

Properties and qualities

Slope: 5 to 15 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 20 to 40 inches to dense material
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 18 to 26 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.7 inches)

Interpretive groups

Land capability (nonirrigated): 6s

Typical profile

0 to 3 inches: Highly decomposed plant material
3 to 5 inches: Very fine sandy loam
5 to 30 inches: Gravelly fine sandy loam

30 to 65 inches: Fine sandy loam

Data Source Information

Soil Survey Area: Somerset County Area and Parts of Franklin and Oxford Counties, Maine
Survey Area Data: Version 12, Dec 19, 2008

Somerset County Area and Parts of Franklin and Oxford Counties, Maine

HTD—Hermon-Rawsonville-Skerry association, 12 to 30 percent slopes

Map Unit Setting

Elevation: 350 to 2,500 feet
Mean annual precipitation: 35 to 40 inches
Frost-free period: 60 to 120 days

Map Unit Composition

Hermon and similar soils: 55 percent
Rawsonville and similar soils: 15 percent
Skerry and similar soils: 15 percent

Description of Hermon

Setting

Landform: Ground moraines, hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Sandy-skeletal supraglacial meltout till derived from granite and gneiss

Properties and qualities

Slope: 15 to 30 percent
Surface area covered with cobbles, stones or boulders: 9.0 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Somewhat excessively drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to very high (1.42 to 14.17 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 3.8 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 1 inches: Highly decomposed plant material
1 to 3 inches: Sandy loam
3 to 26 inches: Very gravelly loamy sand
26 to 65 inches: Very gravelly coarse sand

Description of Skerry

Setting

Landform: Drumlinoid ridges
Landform position (two-dimensional): Backslope

Landform position (three-dimensional): Head slope
Down-slope shape: Linear
Across-slope shape: Concave
Parent material: Coarse-loamy lodgment till derived from mica schist and/or coarse-loamy lodgment till derived from granite and gneiss

Properties and qualities

Slope: 12 to 20 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 18 to 30 inches to dense material
Drainage class: Moderately well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 15 to 23 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 3.6 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 1 inches: Highly decomposed plant material
1 to 3 inches: Fine sandy loam
3 to 30 inches: Gravelly fine sandy loam
30 to 65 inches: Gravelly sandy loam

Description of Rawsonville

Setting

Landform: Ridges
Landform position (two-dimensional): Footslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy supraglacial meltout till derived from granite and gneiss

Properties and qualities

Slope: 15 to 30 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 20 to 40 inches to lithic bedrock
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately high (0.00 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Moderate (about 7.4 inches)

Interpretive groups

Land capability (nonirrigated): 6s

Typical profile

0 to 3 inches: Highly decomposed plant material

3 to 5 inches: Very fine sandy loam
5 to 19 inches: Fine sandy loam
19 to 35 inches: Cobbly fine sandy loam
35 to 39 inches: Bedrock

Data Source Information

Soil Survey Area: Somerset County Area and Parts of Franklin and Oxford Counties, Maine
Survey Area Data: Version 12, Dec 19, 2008

Somerset County Area and Parts of Franklin and Oxford Counties, Maine

MED—Marlow-Dixfield-Rawsonville association, 12 to 30 percent slopes

Map Unit Setting

Elevation: 350 to 2,500 feet
Mean annual precipitation: 35 to 40 inches
Frost-free period: 60 to 120 days

Map Unit Composition

Marlow and similar soils: 50 percent
Dixfield and similar soils: 25 percent
Rawsonville and similar soils: 15 percent

Description of Marlow

Setting

Landform: Drumlinoid ridges
Landform position (two-dimensional): Summit
Landform position (three-dimensional): Interfluve
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy lodgment till derived from granite and/ or coarse-loamy lodgment till derived from mica schist

Properties and qualities

Slope: 15 to 30 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 20 to 40 inches to dense material
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 18 to 26 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.7 inches)

Interpretive groups

Land capability (nonirrigated): 6s

Typical profile

0 to 3 inches: Highly decomposed plant material
3 to 5 inches: Very fine sandy loam
5 to 30 inches: Gravelly fine sandy loam
30 to 65 inches: Fine sandy loam

Description of Dixfield

Setting

Landform: Drumlinoid ridges
Landform position (two-dimensional): Backslope

Landform position (three-dimensional): Talf
Down-slope shape: Linear
Across-slope shape: Convex
Parent material: Coarse-loamy lodgment till derived from mica schist

Properties and qualities

Slope: 12 to 25 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 18 to 36 inches to dense material
Drainage class: Moderately well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 16 to 29 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.3 inches)

Interpretive groups

Land capability (nonirrigated): 6s

Typical profile

0 to 2 inches: Highly decomposed plant material
2 to 3 inches: Gravelly fine sandy loam
3 to 22 inches: Fine sandy loam
22 to 65 inches: Gravelly fine sandy loam

Description of Rawsonville

Setting

Landform: Ridges
Landform position (two-dimensional): Footslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy supraglacial meltout till derived from granite and gneiss

Properties and qualities

Slope: 15 to 30 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 20 to 40 inches to lithic bedrock
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately high (0.00 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Moderate (about 7.4 inches)

Interpretive groups

Land capability (nonirrigated): 6s

Typical profile

0 to 3 inches: Highly decomposed plant material
3 to 5 inches: Very fine sandy loam
5 to 19 inches: Fine sandy loam

19 to 35 inches: Cobbly fine sandy loam
35 to 39 inches: Bedrock

Data Source Information

Soil Survey Area: Somerset County Area and Parts of Franklin and Oxford Counties, Maine
Survey Area Data: Version 12, Dec 19, 2008

Somerset County Area and Parts of Franklin and Oxford Counties, Maine

MLE—Marlow-Hogback-Berkshire association, 25 to 45 percent slopes

Map Unit Setting

Elevation: 350 to 2,500 feet
Mean annual precipitation: 35 to 40 inches
Frost-free period: 90 to 115 days

Map Unit Composition

Marlow and similar soils: 35 percent
Hogback and similar soils: 25 percent
Berkshire and similar soils: 15 percent

Description of Marlow

Setting

Landform: Drumlinoid ridges
Landform position (two-dimensional): Summit
Landform position (three-dimensional): Interfluve
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy lodgment till derived from granite and/or coarse-loamy lodgment till derived from mica schist

Properties and qualities

Slope: 25 to 45 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 20 to 40 inches to dense material
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.03 to 0.06 in/hr)
Depth to water table: About 18 to 26 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.7 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 3 inches: Highly decomposed plant material
3 to 5 inches: Very fine sandy loam
5 to 30 inches: Gravelly fine sandy loam
30 to 65 inches: Fine sandy loam

Description of Hogback

Setting

Landform: Ridges
Landform position (two-dimensional): Footslope

Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy supraglacial meltout till derived from mica schist

Properties and qualities

Slope: 25 to 45 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 10 to 20 inches to lithic bedrock
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately high (0.00 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 5.3 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 2 inches: Highly decomposed plant material
2 to 5 inches: Very fine sandy loam
5 to 16 inches: Gravelly very fine sandy loam
16 to 19 inches: Very fine sandy loam
19 to 23 inches: Bedrock

Description of Berkshire

Setting

Landform: Till plains
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Rise
Down-slope shape: Linear
Across-slope shape: Convex
Parent material: Coarse-loamy supraglacial meltout till derived from mica schist and/or coarse-loamy supraglacial meltout till derived from granite and gneiss

Properties and qualities

Slope: 30 to 45 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (0.60 to 6.00 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Moderate (about 6.3 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 2 inches: Highly decomposed plant material
2 to 6 inches: Very fine sandy loam
6 to 30 inches: Fine sandy loam
30 to 65 inches: Gravelly sandy loam

Data Source Information

Soil Survey Area: Somerset County Area and Parts of Franklin and Oxford Counties, Maine
Survey Area Data: Version 12, Dec 19, 2008

Somerset County Area and Parts of Franklin and Oxford Counties, Maine

SSD—Saddleback-Sisk-Rock outcrop association, 15 to 30 percent slopes

Map Unit Setting

Elevation: 2,500 to 4,180 feet
Mean annual precipitation: 40 to 60 inches
Mean annual air temperature: 32 to 37 degrees F
Frost-free period: 30 to 90 days

Map Unit Composition

Saddleback and similar soils: 35 percent
Sisk and similar soils: 30 percent
Rock outcrop: 15 percent

Description of Saddleback

Setting

Landform: Mountains
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Upper third of mountainflank
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy supraglacial meltout till derived from mica schist and/or coarse-loamy supraglacial meltout till derived from granite and gneiss

Properties and qualities

Slope: 15 to 30 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 10 to 20 inches to lithic bedrock
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately high (0.00 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.9 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 5 inches: Highly decomposed plant material
5 to 6 inches: Fine sandy loam
6 to 19 inches: Fine sandy loam
19 to 23 inches: Bedrock

Description of Sisk

Setting

Landform: Mountains
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Center third of mountainflank
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy lodgment till derived from mica schist and/or coarse-loamy lodgment till derived from granite and gneiss

Properties and qualities

Slope: 15 to 30 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 20 to 36 inches to dense material
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately high (0.00 to 0.60 in/hr)
Depth to water table: About 18 to 26 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.7 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 2 inches: Highly decomposed plant material
2 to 3 inches: Silt loam
3 to 22 inches: Silt loam
22 to 65 inches: Gravelly fine sandy loam

Description of Rock Outcrop

Properties and qualities

Slope: 15 to 30 percent
Depth to restrictive feature: 0 inches to lithic bedrock
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately high (0.00 to 0.20 in/hr)

Interpretive groups

Land capability (nonirrigated): 8s

Typical profile

0 to 60 inches: Bedrock

Data Source Information

Soil Survey Area: Somerset County Area and Parts of Franklin and Oxford Counties, Maine
Survey Area Data: Version 12, Dec 19, 2008

Somerset County Area and Parts of Franklin and Oxford Counties, Maine

SSE—Saddleback-Sisk-Rock outcrop association, 20 to 45 percent slopes

Map Unit Setting

Elevation: 2,500 to 4,180 feet
Mean annual precipitation: 40 to 60 inches
Mean annual air temperature: 32 to 37 degrees F
Frost-free period: 30 to 90 days

Map Unit Composition

Sisk and similar soils: 30 percent
Saddleback and similar soils: 30 percent
Rock outcrop: 15 percent

Description of Saddleback

Setting

Landform: Mountains
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Upper third of mountainflank
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy supraglacial meltout till derived from mica schist and/or coarse-loamy supraglacial meltout till derived from granite and gneiss

Properties and qualities

Slope: 20 to 45 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 10 to 20 inches to lithic bedrock
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately high (0.00 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.9 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 5 inches: Highly decomposed plant material
5 to 6 inches: Fine sandy loam
6 to 19 inches: Fine sandy loam
19 to 23 inches: Bedrock

Description of Sisk

Setting

Landform: Mountains
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Center third of mountainflank
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Coarse-loamy lodgment till derived from mica schist and/or coarse-loamy lodgment till derived from granite and gneiss

Properties and qualities

Slope: 30 to 45 percent
Surface area covered with cobbles, stones or boulders: 1.6 percent
Depth to restrictive feature: 20 to 36 inches to dense material
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately high (0.00 to 0.60 in/hr)
Depth to water table: About 18 to 26 inches
Frequency of flooding: None
Frequency of ponding: None
Available water capacity: Low (about 4.7 inches)

Interpretive groups

Land capability (nonirrigated): 7s

Typical profile

0 to 2 inches: Highly decomposed plant material
2 to 3 inches: Silt loam
3 to 22 inches: Silt loam
22 to 65 inches: Gravelly fine sandy loam

Description of Rock Outcrop

Properties and qualities

Slope: 20 to 45 percent
Depth to restrictive feature: 0 inches to lithic bedrock
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately high (0.00 to 0.20 in/hr)

Interpretive groups

Land capability (nonirrigated): 8s

Typical profile

0 to 60 inches: Bedrock

Data Source Information

Soil Survey Area: Somerset County Area and Parts of Franklin and Oxford Counties, Maine
Survey Area Data: Version 12, Dec 19, 2008

EXHIBIT S-2-D:

CORPORATE GOOD STANDING

State of Maine

Department of the Secretary of State

I, the Secretary of State of Maine, certify *that according to the provisions of the Constitution and Laws of the State of Maine, the Department of the Secretary of State is the legal custodian of the Great Seal of the State of Maine which is hereunto affixed and of the reports of qualification of foreign business corporations in this State and annual reports filed by the same.*

I further certify *that TRANSCANADA MAINE WIND DEVELOPMENT INC., a DELAWARE corporation, is a duly qualified foreign business corporation under the laws of the State of Maine and that the application for authority to transact business in this State was filed on May 15, 2006.*

I further certify *that said foreign business corporation has filed annual reports due to this Department, and that no action is now pending by or on behalf of the State of Maine to forfeit the authority to transact business in this State and that according to the records in the Department of the Secretary of State, said foreign business corporation is a legally existing business corporation in good standing under the laws of the State of Maine at the present time.*

In testimony whereof, I have caused the Great Seal of the State of Maine to be hereunto affixed. Given under my hand at Augusta, Maine, this sixth day of March 2009.

MATTHEW DUNLAP

Secretary of State

SUPPLEMENT S-3

Tracking No.	For office use
Permit No.	

Maine Land Use Regulation Commission
Department of Conservation

Supplement S-3

Requirements for Wetland Alterations

Applicant Name(s):	Project Location (Township and County):
TransCanada Energy, Ltd.	Kibby and Chain of Ponds Townships, Franklin County

NATURE OF WETLAND ALTERATION See Attachment S3-A

1. Describe in detail the purpose and need for the proposed wetland alteration and the type of activity involved (use additional paper if needed).

2. Will your proposal alter any amount of land that is a mapped P-WL subdistrict or any ground below the normal high water mark of a lake, pond, river, stream, or intertidal area? ☐ Yes ☒ No

3. Will your proposal alter an acre or more of any land area, either upland or wetland? ☒ Yes ☐ No

   3a. If yes, are there wetlands present within the boundaries of your project area (as determined by a qualified wetland professional)? ☒ Yes ☐ No

WETLAND TYPE AND AMOUNT OF ALTERATION See Attachment S3-A

4. What type of wetland(s) will be altered? (check all that apply) Provide the amount of wetland area (in square feet) that is proposed to be altered within each category that is checked off, then calculate the total area of wetland alteration.

   ☐ P-WL1: Wetland of special significance ________ sq. ft.
   ☐ P-WL2: Scrub shrub wetland ________ sq. ft.
   ☐ P-WL3: Forested wetland ________ sq. ft.

   TOTAL AREA OF WETLAND ALTERATION: ________ sq. ft.

5. Provide the amount of wetland area (in square feet) that is proposed to be altered within each of the following categories:

   ☐ Coastal wetland ________ sq. ft. ☐ River, stream or brook bottom ________ sq. ft.
   ☒ Freshwater wetland ________ sq. ft. ☐ Lake or pond bottom ________ sq. ft.

6. Do the wetlands to be altered contain any critically imperiled (S1) or imperiled (S2) natural communities? ☐ Yes ☐ No

PREVIOUS ALTERATION, AVOIDANCE, EROSION/SEDIMENTATION CONTROL See Attachment S3-A

7. Has any wetland area been previously altered on the property? ☒ Yes ☐ No

   7a. If yes, provide the date, purpose, and amount of previous alteration, and whether permits were obtained.
   See Attachment S3-A

8. Is there a reasonable way for you to conduct your project that avoids alteration of wetland areas? ☒ Yes ☐ No

   8a. If no, explain why not and describe how do you propose to minimize the amount of wetland to be altered.
   See Attachment S3-A

9. How will you keep disturbed soils from eroding into nearby lakes, ponds, rivers, streams, intertidal areas, or other wetlands?
   See Attachment S3-A

LEVEL OF WETLAND REVIEW, REQUIRED EXHIBITS

10. Determine the level of wetland review required for your project (check only one option!) and submit all necessary exhibits with this supplement (see instructions for details).

	Level of Review	Required Exhibits
☐ Altering a P-WL1 of any size. ☐ Altering 15,000 – 43,559 sq. ft. of a P-WL2 or P-WL3 containing S1 or S2 communities. ☐ Altering 43,560 sq. ft. or more or a P-WL2 or P-WL3.	Tier 3	S-3A, S-3B, S-3C, S-3D
☐ Altering 20,000 – 43,560 sq. ft. of a P-WL2 or P-WL3 not containing S1 or S2 communities.	Tier 2	S-3A, S-3B, S-3C, S-3D
☐ Altering 15,000 – 19,999 sq. ft. of a P-WL2 or P-WL3 not containing S1 or S2 communities.	Tier 2	S-3A, S-3B
☐ Altering 4,300 – 14,999 sq. ft. of a P-WL2 or P-WL3.	Tier 1	S-3A
☒ Altering less than 4,300 sq. ft. of a P-WL2 or P-WL3.	None	S-3A

S3-A. WETLAND MAP OR DELINEATION.

Submit a sketch drawing or a map that identifies the location and type of wetlands within the project area, as follows:

- ☒ For projects that will alter less than 4,300 sq. ft. of a P-WL2 or P-WL3, show the location of the wetland in relation to your project area. You may include this information on your LURC permit application site plan (Exhibit D) instead. See permit application Exhibit D.
- ☐ For projects that will impact only a water body (such as a lake, pond, stream, river, or intertidal area), submit a map, drawn to scale, that shows the normal high and low water marks of the water body and the proposed wetland impact area. If you are submitting a LURC permit application, you may include this information on your site plan (Exhibit D) instead.
- ☐ For projects requiring Tier 1 wetland review, submit a map, drawn to scale, that indicates the types and locations of wetlands within the project area; the proposed wetland impact area; locations of streams and other natural features; and distances of lakes, ponds, streams, rivers, intertidal areas, and wetlands from the nearest proposed structure or disturbed area.
- ☐ For projects requiring Tier 2 or 3 wetland review, submit a wetland delineation, conducted by a qualified wetlands professional, along with a report describing the physical characteristics of the wetland. The wetland delineation must be conducted using the methods described in the U.S. Army Corps of Engineers Wetland Delineation Manual (1987). For a Tier 2 review, a map must show the wetland boundaries, but the associated field sheets (sample plot logs) do not need to be submitted with this supplement (LURC may request field sheets to be submitted on some projects, depending upon the type of resources to be impacted, the amount of proposed impact, or the nature of the proposal). For a Tier 3 review, a map and field sheets (sample plot logs) must be submitted with this supplement.

S3-B. ALTERNATIVES ANALYSIS.

The alternatives analysis is a narrative that explains how your project has been designed to have the least amount of impact on the wetland. In addition to explaining how your project will alter the least amount of wetland possible, you must also explain why other alternatives to the project are not feasible, including the “no action” alternative (that is, not doing the project at all). As you plan your project, remember to lay it out and use construction techniques that will have the least amount of effect on the wetland. Don’t fill or disturb any area of wetland if there is a way to do your project that will avoid it. For example, do not plan to place a structure in a wetland if it can be placed on upland, or plan to drive heavy machinery on the wetland if it can be avoided.

> Under LURC’s standards for wetland alterations, projects requiring certain types of wetland review must either avoid alteration of wetland areas to the extent feasible, considering natural features, cost, existing technology and logistics based on the overall purpose of the project (Tier 1); or must not cause a loss in wetland area, functions and values if there is a practicable alternative to the project that would be less damaging to the environment (Tier 2 or 3). Contact the LURC office that serves your area for additional guidance or to obtain a copy of LURC’s standards for wetland alterations.

S3-C. FUNCTIONAL ASSESSMENT.

A functional assessment is an evaluation of the functions and values of a wetland that is prepared by a qualified wetlands professional. The preferred method for preparing a functional assessment is the Highway Methodology, although best professional judgment is also accepted under certain circumstances. Contact the LURC office that serves your area for more information.

> Certain projects are exempt from the functional assessment and compensation plan requirements. Contact the main LURC office in Augusta for guidance on which projects are exempt from these requirements.

S3-D. COMPENSATION PLAN.

Compensation is required for certain projects where the functional assessment has shown that there will be a loss of wetland functions and values. Because the compensation plan is tied to the results of the functional assessment, the need for a compensation plan is determined either during a pre-application meeting with LURC, or in consultation with LURC once the functional assessment has been submitted. If compensation is required, the compensation plan must meet the standards found in the Commission’s Wetland Compensation Guidelines. Contact the LURC office that serves your area to obtain a copy of this document.

ATTACHMENT S-3-A:

WETLAND INFORMATION

ATTACHMENT S-3A: WETLAND INFORMATION

Although there has not been a formal wetland delineation done along the access trail and at the met tower sites, it is likely there is only one wetland in these areas and, as discussed below, permanent wetland impacts will be avoided. A preliminary wetland assessment was conducted based on a desktop review of LURC mapped zones, NWI maps, Franklin County soil surveys and observations at the site made of the topography, slopes and landscape position of the trails and met tower sites. The met tower sites are located on the top of the ridge, and it is unlikely that any of these sites are wetland, and there will be no permanent wetland impact at these sites. In the unlikely event that wetlands are determined to be present at the met tower site, work will cease and the applicant will consult with LURC staff prior to proceeding further.

Additionally, there will not be any permanent wetland impacts associated with construction and use of the access trails. The potential wetland area is associated with the stream crossing on the existing access road. A culvert at this site was removed after this road was no longer actively used for timber harvesting. A temporary timber mat bridge will be placed at this crossing to span the stream and associated wetland during clearing, construction, and geotechnical survey activities. If these activities are performed during winter and frozen ground conditions, the potential for impacts to soils is minimal. When spring thaw arrives, equipment access will be restricted until soil conditions are appropriate (i.e., not saturated).

A soil survey and wetland delineation effort, with protocol and methodology developed in consultation with the State Soil Scientist, will be performed once snow cover is gone. If access and construction activities must continue after spring thaw, equipment will also be restricted until the soil survey and wetland delineation determine there are no wetlands within the trail area.