## SNAPSHOT

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2009F</th>
<th>2010F</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cash flow (C$ millions)</strong></td>
<td>$6,969</td>
<td>$5,900 - $6,100</td>
<td>$6,500 - $6,900</td>
</tr>
<tr>
<td><strong>Per share - basic (C$)</strong></td>
<td>$12.89</td>
<td>$10.70 - $11.45</td>
<td>$12.00 - $12.70</td>
</tr>
<tr>
<td><strong>Capital expenditures (C$ millions)</strong></td>
<td>$7,451</td>
<td>$3,120</td>
<td>$3,922</td>
</tr>
<tr>
<td><strong>Dividend (C$/share)</strong></td>
<td>$0.40</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Common shares (thousands)</strong></td>
<td>540,991</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Production (annual average, before royalties)

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2009F</th>
<th>2010F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil (mbbl/d)</td>
<td>316</td>
<td>352 - 363</td>
<td>400 - 445</td>
</tr>
<tr>
<td>Natural gas (mmcf/d)</td>
<td>1,495</td>
<td>1,305 - 1,314</td>
<td>1,117 - 1,185</td>
</tr>
<tr>
<td>BOE (mboe/d)</td>
<td>565</td>
<td>570 - 582</td>
<td>586 - 643</td>
</tr>
</tbody>
</table>

(1) Based upon the following actual and strip pricing, including the impact of hedging

<table>
<thead>
<tr>
<th></th>
<th>2009F</th>
<th>2010F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil WTI (US$/bbl)</td>
<td>$62.42</td>
<td>$81.94</td>
</tr>
<tr>
<td>Natural gas NYMEX (US$/mmbtu)</td>
<td>$4.17</td>
<td>$5.87</td>
</tr>
<tr>
<td>Heavy oil diff (US$/bbl)</td>
<td>$10.04</td>
<td>$10.09</td>
</tr>
<tr>
<td>C$/US$</td>
<td>$0.88</td>
<td>$0.94</td>
</tr>
</tbody>
</table>

### Conventional reserves (after royalties as at December 31, 2008 – constant pricing)

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved oil (mmbbl)</td>
<td>1,346</td>
<td></td>
</tr>
<tr>
<td>Proved natural gas (bcf)</td>
<td>3,684</td>
<td></td>
</tr>
<tr>
<td>Proved BOE (mboe)</td>
<td>1,960</td>
<td></td>
</tr>
<tr>
<td>Proved and probable BOE (mboe)</td>
<td>2,996</td>
<td></td>
</tr>
</tbody>
</table>

### Synthetic crude oil reserves (after royalties as at December 31, 2008 – constant pricing)

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved (mmbbl)</td>
<td>1,946</td>
<td></td>
</tr>
<tr>
<td>Proved and probable (mmbbl)</td>
<td>2,944</td>
<td></td>
</tr>
</tbody>
</table>
Who is Canadian Natural?

- Canadian based E&P company with international exposure
- ~US$40 billion enterprise value
- ~575 mboe/d - Q3/09
  - 62% crude oil weighted
- ~586 - 643 mboe/d - 2010B
- Returns focused
- Major oil sands player
  - Major in-situ producer with several projects in inventory
  - Major mining project currently ramping production

Our Strategy

- Capital allocation to maximize value
- Defined growth / value enhancement plans by product / basin
- Balance
  - Product mix
  - Project time horizons
  - Drill bit and acquisitions
  - Strong balance sheet
- Opportunistic acquisitions
- Control costs through area knowledge and domination of core focus areas
Heavy Oil Assets

- Reliable conventional production
- Pelican Lake EOR development
  - Access additional 247 - 370 million barrels of resource potential
- Thermal in-situ development
  - Significant resource potential in current plans
  - ~285,000 bbl/d of additional in-situ production over next 15 years
- Canadian Natural has competitive advantage via its vast land base

Primary Heavy Oil Production Areas

- Current production
  - Crude oil 86 mbbl/d
- Land (net)
  - Developed 0.4 million acres
  - Undeveloped 1.2 million acres
- Facilities
  - Major crude oil processing facilities 5
  - Salt cavern disposal wells 4
  - ECHO pipeline 143 miles
- 2009 forecast activity
  - Wells 494

Note: Reflects Q3/09 actual production, before royalties.
Primary Heavy Oil Production Basics

- Shallow multi-zone formations
  - 400-600m depth
  - 1-3 zones per well
- Vertical or slant wells
  - Oil is produced to tanks on site
  - Trucked to central batteries
- High production rates
  - 30-200 bbl/d, averaging 40 bbl/d
- Short reserve life
  - Less than five years
- Quick payout
- Large land base required
- Low recovery factors
  - 5%-15% OOIP under primary

Simple, Repeatable, Highly Profitable

Heavy Oil Pelican Lake

- World class oil pool
- Efficient, low cost operations
- Polymer flood successful both technically and economically
- Technology enhancement will continue to improve oil recovery

How big is the reservoir?

OOIP* - 4.1 billion barrels Developed Region

Estimated Future Production* 455 mmbbl
Produced to Date** 127 mmbbl

Future Polymer, Waterflood* 399 mmbbl
Produced to Date** 127 mmbbl

Convert waterfloods to polymer
Polymer flood

Produced to Date**

*Includes proved and probable (December 31, 2008) reserves and contingent resources. **Estimated at December 31, 2008.

Massive Resource to Exploit
Pelican Lake Polymer Flood

• What is a polymer?
  – It is a polyacrylamide powder mixed with water

• Why does it help recovery?
  – It increases the viscosity of water and improves vertical and aerial sweep efficiencies by reducing fingering

• What additional facilities are required?
  – Water handling capability at batteries
  – Polymer hydration units

• Polymer optimization
  – Testing polymer response in pool areas containing higher oil viscosities
  – Evaluating alkaline surfactants usage to reduce residual oil

Thermal Oil Sands Holdings

Land
  – McMurray - 377,000 net acres
    • Birch Mountain
    • Gregoire
    • Kirby
    • Grouse
    • Leismer
  – Clearwater - 201,000 net acres
    • Primrose
    • Wolf Lake

Great Assets, Huge Land Base
**Thermal Heavy Oil Potential**

- McMurray: 22 billion barrels
- Kirby, Grouse, Leismer, Birch Mountain, Gregoire
- Clearwater, Primrose: 11 billion barrels
- Contingent Resources: 4.5 billion barrels
- Proved and Probable Reserves*: 1.1 billion barrels
- Estimated Bitumen in Place: 33 billion barrels total
- 285,000 bbl/d incremental production
- Estimated Ultimate Recovery: 5.6 billion barrels total

*December 31, 2008.

**Thermal Heavy Oil Recovery Schemes**

- **Cyclic Steam Stimulation (CSS)**
  - Inject steam from a single horizontal or vertical well
  - Can use high pressure
  - Requires solution gas drive
  - Wet steam SOR (~1.25 dry steam SOR)

- **Steam Assisted Gravity Drainage (SAGD)**
  - Continuous injection of steam into upper well and gravity drainage to lower producer well
  - Higher recovery factor
  - Clean, continuous reservoir

*Match Scheme to Reservoir*
## Thermal Heavy Oil Growth Plan

<table>
<thead>
<tr>
<th>Phase</th>
<th>Oil Production Capacity (bbl/d)</th>
<th>Target Timing (year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Primrose North/South</td>
<td>80,000</td>
<td>On Stream</td>
</tr>
<tr>
<td>2 Primrose East</td>
<td>40,000</td>
<td>On Stream</td>
</tr>
<tr>
<td>3 Kirby</td>
<td>45,000</td>
<td>2013</td>
</tr>
<tr>
<td>4 Grouse</td>
<td>60,000</td>
<td>2014</td>
</tr>
<tr>
<td>5 Birch Mountain East</td>
<td>60,000</td>
<td>2016</td>
</tr>
<tr>
<td>6 Gregoire 1</td>
<td>60,000</td>
<td>2018</td>
</tr>
<tr>
<td>7 CSS - Follow-up Process</td>
<td>30,000</td>
<td>2018</td>
</tr>
<tr>
<td>8 Leismer</td>
<td>30,000</td>
<td>2020</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>405,000</strong></td>
</tr>
</tbody>
</table>

- 30,000 - 60,000 bbl/d addition every 2 - 3 years

## Thermal Heavy Oil Growth Plan Future Production

- **Production (bbl/d)**: Primrose, Kirby, Grouse, Birch Mtn
- **Years**: 2008 to 2018

Growth for Decades
Heavy Oil
Three Pronged Marketing Plan

Conversion capacity

- Additional refinery conversion capacity
  - Refining: cokers / hydrocrackers
  - Upgrading: bitumen / heavy oil

Pipelines

- Southern Access expansion
- Terasen Phase 1 expansion (Edmonton to Vancouver)
- Pegasus (Patoka to USGC)
- Spearhead (Chicago to Cushing)

Blending

- DilSynbit
- WCS (Western Canadian Select)
- Synbit

Cumulative Incremental Volume

Short Term
Up to 5 years

Medium Term
5 to 10 years

Long Term
>10 years

Access to Incremental Markets Over the Short, Medium and Long Term

Canadian Natural’s Mineable Assets - Horizon Oil Sands

- Mining resources
  - 16 billion barrels in place*, with 6 to 8 billion barrels recoverable**
    - 2.9 billion barrels of net proved and probable SCO
  - Phased development (SCO)
    - 110 mbbl/d capacity (Phase 1)
    - Expansion to 232 to 250 mbbl/d capacity targeted
    - Future expansions to ~500 mbbl/d
  - Significant free cash flow generation for decades

World Class Opportunity - 40 Year Reserve ~500* mbbl/d - No Production Declines

*Discovered initially-in-place estimate.
**Includes mineable reserves and contingent resources.
Horizon Oil Sands
Production Plan

- First synthetic production - February 28, 2009
- Staged production
  - Ramp up to full capacity of 110,000 bbl/d SCO throughout 2009 and mid 2010
    - New equipment - may have premature failures
    - Fine tune plant to design rates and operational reliability
- 2009 production plan
  - Annual equivalent daily production of 50,000 to 54,000 barrels of SCO
- 2010 production plan
  - Annual equivalent daily production of 90,000 to 105,000 barrels of SCO

Horizon Oil Sands
2010 Plan

- Establish reliability on production
- Identify debottlenecking opportunities
- Complete lessons learned from Phase 1
- Continue Tranche 2 capital
- Engineering for Phase 2/3 expansion
Horizon Oil Sands
Expansion to 232,000 - 250,000 bbl/d

- Previously segregated into four tranches
  - Tranche 1 - complete
  - Tranche 2 - portions of engineering underway, balance under re-assessment
  - Tranche 3 - re-profile timing and strategy
  - Tranche 4 - re-profile timing and strategy

- Timing of construction critical to cost control
  - Take advantage of slow times

- Expect to evaluate / segregate into even smaller components with interim production
- Avoid “mega” project phenomena
- Not driven to production increases at the expense of higher costs

---

Horizon Oil Sands
Phase 1 Wall of Cash Flow

Cash Flow (C$mm)

$0 $200 $400 $600 $800 $1,000 $1,200 $1,400 $1,600


WTI = US$56.00

Note: After tax and royalty. *2009 WTI = US$48.54.

Free Cash Flow - Sustainable for Decades
Canadian Natural
2010 Overall Plan

1) Pay down debt
2) Ramp up Horizon Oil Sands production
   – Lessons learned, progress expansion cost estimate
3) Conserve our land base
   – Expiries
   – Drainage
4) Significant primary heavy oil program
5) Progress thermal development
6) Prepare Kirby for sanction
7) Progress Pelican Lake polymer flood
8) Increased focus on EOR in light oil projects
9) Focus on value growth not production growth

Focus on Value Growth
Forward Looking Statements

Certain statements in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believes", "anticipates", "expects", "plans", "estimates", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on specific assumptions on which the Company's current guidance is based, including the achievement of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others, general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products, volatility and assumptions regarding crude oil and natural gas prices, fluctuations in currency and interest rates, changes in the cost of capital and capital requirements, changing fiscal terms and royalty obligations, business, political uncertainty, including actions of or against terrorists, insurgent groups or other conflicts including conflict between states, industry capacity, ability of the Company to implement its business strategy, including exploration and development activities, impact of competition, the Company's definition of reserves, availability and cost of seismic, drilling and other equipment, ability of the Company and its subsidiaries to complete its capital programs, the Company's and its subsidiaries' ability to secure adequate transportation for its products, unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labor required to build its thermal and oil sands mining projects or to maintain its production facilities; and other factors inherent in the exploration and production activities, and the ability to replace and expand crude oil and natural gas reserves, including access to the necessary capital. Such forward-looking statements are based on current expectations, estimates and projections about Canadian Natural Resources Limited (the "Company") and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the document or report in which they are contained and are subject to known and unknown risks, uncertainties and other factors that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. The Company has included the forward-looking statements in this document as a result of the Company's belief that they are reasonable based on current circumstances and experience, as well as management's independent assessment of additional information available to the Company. The Company cautions investors that the Company is under no obligation to publicly update or otherwise revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

Reporting Disclosures

Special Note Regarding Currency, Production and Reserves

In this document, all dollar amounts referred to in Canadian dollars unless otherwise stated. Production data is presented on a before royalties basis unless otherwise noted. All referenced crude oil is averaged prices. The symbol "bbl" means barrel or barrels. The symbol "mcf" means thousand cubic feet of natural gas or one barrel of crude oil. The symbol "MMcf" means million cubic feet of natural gas or one thousand barrels of crude oil. The symbol "MMbbl" means million barrels of crude oil. The symbol "MMMMcf" means billion cubic feet of natural gas or one million barrels of crude oil. The symbol "MMMMbbl" means one billion barrels of crude oil. The symbol "EUR" means Equivalent Recovery Unit. The symbol "$/MMcf" means Canadian dollars per thousand cubic feet of natural gas. The symbol "$/MMbbl" means Canadian dollars per million barrels of crude oil. 1 bbl: 6 mcf is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head. Historical financial information is not comparable to historical financial information of other companies that are not accounted for in accordance with Canadian generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures used by other companies. The Company uses these non-GAAP measures to evaluate its financial performance and to provide a more meaningful analysis of trends in its financial performance. The non-GAAP measures are not intended to be alternatives to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

Special Note Regarding non-GAAP Financial Measures

Management's discussion and analysis includes references to financial measures commonly used in the oil and gas industry, such as cash flow, cash flow per share and EBITDA (net earnings before interest, taxes, depreciation and amortization), as calculated by the Company. These financial measures are not defined under Canadian generally accepted accounting principles ("GAAP") and are therefore referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures used by other companies. The performance of the Company's businesses is evaluated through financial indicators other than net earnings, such as annual alternative or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.
Appendices

Overview of Today’s Operations

North America

<table>
<thead>
<tr>
<th></th>
<th>Crude Oil &amp; NGLs (mbbl/d)</th>
<th>Natural Gas (mmcf/d)</th>
<th>BOE/d (6:1)</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010B Production</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- conventional</td>
<td>256 - 270</td>
<td>1,089 - 1,146</td>
<td>430 - 460</td>
<td></td>
</tr>
<tr>
<td>2009F Production</td>
<td>233 - 238</td>
<td>1,279 - 1,286</td>
<td>446 - 450</td>
<td></td>
</tr>
<tr>
<td>2008 Production</td>
<td>243</td>
<td>1,472</td>
<td>488</td>
<td>87%</td>
</tr>
<tr>
<td>- proved reserves</td>
<td>1,507</td>
<td>4,017</td>
<td>1,737</td>
<td>80%</td>
</tr>
<tr>
<td>2010B Production</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- oil sands mining</td>
<td>90 - 105</td>
<td>90 - 105</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009F Production</td>
<td>50 - 54</td>
<td>50 - 54</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008 Proved reserves</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Offshore West Africa

<table>
<thead>
<tr>
<th></th>
<th>Crude Oil &amp; NGLs (mbbl/d)</th>
<th>Natural Gas (mmcf/d)</th>
<th>BOE/d (6:1)</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010B Production</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- per day</td>
<td>31 - 36</td>
<td>17 - 21</td>
<td>34 - 40</td>
<td></td>
</tr>
<tr>
<td>2009F Production</td>
<td>37 - 39</td>
<td>9 - 10</td>
<td>39 - 41</td>
<td></td>
</tr>
<tr>
<td>2008 Production</td>
<td>45</td>
<td>10</td>
<td>47</td>
<td>8%</td>
</tr>
<tr>
<td>- proved reserves</td>
<td>296</td>
<td>67</td>
<td>267</td>
<td>12%</td>
</tr>
</tbody>
</table>

North Sea

<table>
<thead>
<tr>
<th></th>
<th>Crude Oil &amp; NGLs (mbbl/d)</th>
<th>Natural Gas (mmcf/d)</th>
<th>BOE/d (6:1)</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010B Production</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- per day</td>
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</tr>
<tr>
<td>- proved reserves</td>
<td>296</td>
<td>67</td>
<td>267</td>
<td>12%</td>
</tr>
</tbody>
</table>

Note: Production numbers reflect Q3/09 actual production, before royalties. All figures are before royalties.

Canadian Targeted Asset Base with Selected International Exposure
Who is Canadian Natural?

- Consistent value creation through successful
  - Exploitation
  - Exploration
  - Opportunistic acquisitions
- 100% of reserves subject to independent evaluation

Why Invest in Canadian Natural’s Future

- Strong, low-risk asset base
  - Includes world class oil sands in-situ and mining developments
  - Largest producer of heavy crude oil in western Canada
  - Largest net undeveloped land base in western Canada
  - Second largest producer of natural gas in western Canada
- Balanced and large size reduces risk
- Track record of value creation
- Proven / committed management
- Winning exploitation-based strategy
- Defined plan for profitable growth
- Focused on value creation
**Historical Production Growth**

Canadian Natural Production - 1989 to Present

- Significant Price Reduction

**A History of Value Creation**

- Daily Production Per 10,000 Shares (boe/d)
  - Gas
  - Oil
- Reserves Per Share*
  - Gas
  - Oil
- Cash Flow Per Share*
  - 28% CAGR
- Conventional Pretax Net Asset Value Per Share*
  - 28% CAGR

*Refer to page 3 of the 2008 Canadian Natural Annual Report for a detailed description of notes.

**Consistent Growth**
Committed Management

- Substantial management and director wealth at stake
  - Strong motivation for management to perform
  - Delivers clear alignment with shareholder interests

Management / Directors Stock Ownership (US$ millions)

<table>
<thead>
<tr>
<th>Company</th>
<th>Stock Ownership (US$ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CNQ</td>
<td>$1,612</td>
</tr>
<tr>
<td>XTO</td>
<td>$752</td>
</tr>
<tr>
<td>DV/N</td>
<td>$228</td>
</tr>
<tr>
<td>EOG</td>
<td>$198</td>
</tr>
<tr>
<td>ECA</td>
<td>$176</td>
</tr>
<tr>
<td>APA</td>
<td>$189</td>
</tr>
<tr>
<td>APC</td>
<td>$178</td>
</tr>
<tr>
<td>PSD</td>
<td>$106</td>
</tr>
<tr>
<td>NXY</td>
<td>$46</td>
</tr>
<tr>
<td>TLM</td>
<td>$29</td>
</tr>
</tbody>
</table>

Note: Based on share ownership data excluding options and priced at November 3, 2009. Source: Thomson Reuters.

Consistent History of Value Creation

Annualized Sensitivity to Prices

- Annualized and based upon Q3/09 business conditions and sales volumes but excluding financial derivatives

<table>
<thead>
<tr>
<th>Variable</th>
<th>Impact on Cash Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTI +/- US$1.00/bbl</td>
<td>~$100 million</td>
</tr>
<tr>
<td>AECO +/- C$0.10/mcf</td>
<td>~$23 million</td>
</tr>
<tr>
<td>$0.01 change in US$*</td>
<td>~$82 million</td>
</tr>
<tr>
<td>10,000 bbl/d change in crude oil production</td>
<td>~$150 million</td>
</tr>
<tr>
<td>10 mmcf/d change in natural gas production</td>
<td>~$8 million</td>
</tr>
</tbody>
</table>

Significant Upside from Conservative Budget Price Deck

*Includes financial derivatives.
### Canadian Natural 2010 Capital Budget

<table>
<thead>
<tr>
<th></th>
<th>2009F</th>
<th>2010B</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Production (mboe/d)</strong></td>
<td>570 - 582</td>
<td>586 - 643</td>
<td>7%</td>
</tr>
<tr>
<td><strong>Cashflow ($mm)</strong></td>
<td>$5,900 - $6,100</td>
<td>$6,500 - $6,900</td>
<td>12%</td>
</tr>
<tr>
<td><strong>Capital ($mm)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North American Natural Gas</td>
<td>$495</td>
<td>$674</td>
<td>36%</td>
</tr>
<tr>
<td>North American Crude Oil and NGLs</td>
<td>$1,220</td>
<td>$1,900</td>
<td>56%</td>
</tr>
<tr>
<td>North Sea</td>
<td>$170</td>
<td>$199</td>
<td>17%</td>
</tr>
<tr>
<td>Offshore West Africa</td>
<td>$550</td>
<td>$264</td>
<td>(52%)</td>
</tr>
<tr>
<td>Property Acquisitions</td>
<td>$85</td>
<td>$100</td>
<td>18%</td>
</tr>
<tr>
<td>Horizon</td>
<td>$600</td>
<td>$785</td>
<td>31%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$3,120</td>
<td>$3,922</td>
<td>26%</td>
</tr>
<tr>
<td><strong>Free cash flow ($mm)</strong></td>
<td>$2,800 - $3,000</td>
<td>$2,600 - $3,000</td>
<td></td>
</tr>
</tbody>
</table>

*Based on WTI US$81.94 and NYMEX US$5.87.
**Cash flow less Capital.

7% Production Growth While Spending Only 60% of Cash Flow

### Natural Gas Operating Cost Peer Comparison

<table>
<thead>
<tr>
<th>Year</th>
<th>($/mcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q3/05</td>
<td></td>
</tr>
<tr>
<td>Q4/05</td>
<td></td>
</tr>
<tr>
<td>Q1/06</td>
<td></td>
</tr>
<tr>
<td>Q2/06</td>
<td></td>
</tr>
<tr>
<td>Q3/06</td>
<td></td>
</tr>
<tr>
<td>Q4/06</td>
<td></td>
</tr>
<tr>
<td>Q1/07</td>
<td></td>
</tr>
<tr>
<td>Q2/07</td>
<td></td>
</tr>
<tr>
<td>Q3/07</td>
<td></td>
</tr>
<tr>
<td>Q4/07</td>
<td></td>
</tr>
<tr>
<td>Q1/08</td>
<td></td>
</tr>
<tr>
<td>Q2/08</td>
<td></td>
</tr>
<tr>
<td>Q3/08</td>
<td></td>
</tr>
<tr>
<td>Q4/08</td>
<td></td>
</tr>
<tr>
<td>Q1/09</td>
<td></td>
</tr>
<tr>
<td>Q2/09</td>
<td></td>
</tr>
<tr>
<td>Q3/09</td>
<td></td>
</tr>
</tbody>
</table>

Note: Other Producers - NXY, HSE, TLM, ECA, ARC, PWT, PGF:UN. Source: Corporate reports.

Best in Class Versus Established Peers
Heavy Oil Operating Cost Peer Comparison

Note: Other Producers - NXY, HSE, TLM, ECA. CNQ heavy oil operations not including thermal operating costs.

Best in Class Versus Established Peers

Essential Elements to Our Defined Plan

*Includes estimated mineable reserves and contingent resources.

A Growing, Returns - Focused E&P Creating Significant Value
Natural Gas Core Area Summaries

- North and South Plains
  - Conventional exploitation
    - Shallow gas and HSC CBM resource projects
    - Low risk, low cost, highly profitable
- Foothills
  - High impact exploration
    - 14% average annual growth since 2004
- NE British Columbia
  - Unconventional - Muskwa and Montney
    - Low cost entry
- NW Alberta
  - Resource projects - Deep Basin and Montney
    - Repeatable, large scale

Balanced, Cost Effective Growth

Natural Gas Production Base Evolution

- Annual base decline rate is slowing
  - Emphasis on resource plays such as Cardium, shallow, CBM have lower mature declines
  - Reduced new drilling activity reduces first year decline impact
- Measured 93 well drilling program in 2010, results in only a 13% midpoint production decline

Note: Includes production volumes from all acquisitions.
Canadian Natural Gas Assets

• 2010 plan
  – Maintain development of growth projects
  – Expand inventory
  – High grade drilling program and optimize production

Disciplined Development of Strong Gas Assets

Natural Gas Competitive Advantage

• Large land base provides exposure to many play types
  – Conventional
  – Unconventional
  – Deep exploration

• Vast, cost effective infrastructure
  – ~21,000 miles of pipe

• Extensive seismic database
  – >890,000 kilometers of 2D
  – >61,000 sq. kilometers of 3D

• Large balanced inventory

• Excellent people
Natural Gas Defined Resource Potential

- Drilling activity
  - 67% conventional and shallow gas
- Resource growth
  - 60% Deep Basin, Montney/Muskwa

Balanced Short, Mid and Long Term Growth

Resource Plays Exploration Volumes 10 Year Plan

- Key projects
  - Deep Basin - NW AB
  - Montney - NE BC
  - Muskwa - NE BC
- 10 year plan
  - 1,233 wells forecast
  - 395 mmcf/d incremental volume

* Canadian Natural operated.

Disciplined Long Term Growth
Impact of Royalty Review Panel Proposals on Conventional Natural Gas

- Shifted the gas price at which projects are economic upward
- $8.00/mcf is now equivalent to $11.00/mcf
- $7.00/mcf = $9.13/mcf

Pelican Lake EOR Plan

- Polymer flood by end 2008
- 2009 Polymer Plan
- 5 Year Polymer Plan

Polymer Success Leads to Expansion
Pelican Lake Polymer Flood

- **What is a polymer?**
  - It is a polyacrylamide powder mixed with water
- **Why does it help recovery?**
  - It increases the viscosity of water and improves vertical and aerial sweep efficiencies by reducing fingering
- **What additional facilities are required?**
  - Water handling capability at batteries
  - Polymer skids
- **What is the incremental capital cost?**
  - $6.00 to $8.00/bbl oil recovered
- **What is the incremental operating cost?**
  - $0.40 to $0.60/bbl oil recovered

Polymer Flood Optimization

- **Reservoir**
  - Testing polymer response in portions of the pool with higher oil viscosities
  - Evaluating the use of alkaline surfactants to reduce residual oil
  - Optimizing the type and quantities of polymer being used
  - Optimizing injected volumes within the well patterns
- **Infrastructure**
  - Designing / constructing larger mixing skids and distribution systems
  - Mixing polymer with brackish reservoir water rather than fresh water for injection
  - Maximizing water recycling
  - Optimizing facilities for fluid increases due to polymer response
Primary Heavy Oil Enhanced Recovery

- Primary recovery 5-15% OOIP leaving billions of barrels unrecovered
- Enhancing recovery
  - Underway
    - Infill drilling
    - 5-10 wells per acre
    - Selective waterflood applications
    - Selective use of horizontal drilling
  - EOR recovery processes being evaluated
    - Hydrocarbon solvent injections
    - CO₂ injection
    - Polymer flooding

Enormous Potential - Low Cost Barrels

Technology Option
Thermal Geo-steering Well Placement

Capturing More of the Reservoir With Technology Advancement
Thermal Heavy Oil Technology Advancement

Stage 1, CSS recovery factor 20%

Stage 2, Infill recovery factor 30%

Stage 3, Gravity Drainage recovery factor 40%

International Operations

• North Sea
  – Exploitation based value creation
  – Delivering field life extension
  – Generates significant free cash flow
  – Opportunity for acquisition in future years
  – Leveraging technical strengths in Africa

• Offshore West Africa
  – High return, long lead projects
  – Generates significant free cash flow
  – 2008/9 activity
    • Baobab sand issues being dealt with, optimize West Espoir
      – 4 wells drilled over 2008/09
    • Mature Olowi exploitation project
      – First production achieved April 2009

Focus on Free Cash Flow While Setting Up For Future Expansion
**International North Sea**

- Exploitation base similar to WCSB
- Operate ~99% and own ~80% of production
- Infill drilling / recompletions & waterflood optimization
- 1 drill string operating in 2010
- 1 well and 3 well interventions

**Value Creation Through Exploitation Approach**

**International Offshore Côte d’Ivoire**

- **East Espoir**
  - First oil achieved in 2002
  - 4 infills drilled in 2005/6
  - FPSO expansion in 2009
- **West Espoir development**
  - First oil achieved July 2006 increased to ~13 mboe/d in 2007
- **Baobab development**
  - First oil achieved in 2005
  - Sand handling and infill drilling program in 2008/9
    - 4 wells back on production

**Area for Light Oil Growth**
**International Offshore Gabon**

- **Olowi Field development plan**
  - 12 miles offshore in 100 ft of water
  - Already delineated by 15 wells
  - 90% interest and operated
- **First oil in April 2009**
  - Oil leg below large gas cap
  - 34° API crude oil

**Olowi Field - Springboard Into Gabon**

**Horizon Oil Sands Process and Technology**

- Only Proven Technologies Will be Utilized Reducing Technology Risks
**Horizon Oil Sands Site Layout**

**Site Layout Maximizes Resource Recovery and Optimizes Economic Returns**

---

**Horizon Oil Sands Operating Costs**

- **Phase 1 costs are targeted to be between $35.00/bbl to $45.00/bbl in 2009**
  - Impacted by fixed cost effect and lower production
- **Life of mine operating costs**

<table>
<thead>
<tr>
<th>November 2008 Estimate @ 232,000 bbl/d</th>
<th>Oct-07 Estimate</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Cost</td>
<td>Natural</td>
<td>Imported</td>
</tr>
<tr>
<td>Mining</td>
<td>$ 8.04</td>
<td>$ 0.01</td>
</tr>
<tr>
<td>Bitumen production</td>
<td>$ 3.00</td>
<td>$ 0.34</td>
</tr>
<tr>
<td>Upgrading</td>
<td>$ 2.47</td>
<td>$ 4.18</td>
</tr>
<tr>
<td>Utilities &amp; Services</td>
<td>$ 1.69</td>
<td>$ 2.23</td>
</tr>
<tr>
<td>Administration</td>
<td>$ 4.87</td>
<td></td>
</tr>
<tr>
<td>Environmental</td>
<td>$ 1.32</td>
<td></td>
</tr>
<tr>
<td>Total $/bbl for Average Life</td>
<td>$ 21.42</td>
<td>$ 6.76</td>
</tr>
<tr>
<td>Average Sustaining Capital</td>
<td>$ 1.90</td>
<td></td>
</tr>
</tbody>
</table>

**Major Changes - Operating from October 2007**

- **$1.87 Admin - Property tax increase $1.32, Technical Services increase $.33 due to headcount & transfers in of I.T. costs and other overhead costs, Business Services $22 Insurance.**
- **$2.83 Mine increases mainly due to overburden escalation costs, tires & parts increase and higher overheads.**
- **$1.42 Bitumen Production increase due to increases in contract costs, overheads as well as material & supplies higher than expected.**
- **$2.93 Nat Gas Price from $7.03/GJ to $8.98/GJ ($58 WTI prior vs $85.73 WTI current))**
- **$0.52 Utilities & Services increase due to transfer in of headcount, overheads as well as increases in contract costs.**
- **$0.07 Green House Gas increase**
  - Upgrading increase due to increases in contract costs and higher overheads.

**$10.36**
Horizon Oil Sands
Phase 2/3 - Re-Profiling

- **Strategy**
  - Don’t build in a high cost environment
  - Not production driven but “value” driven
  - Smaller project sizes
- **2009 activity**
  - Continue with third OPP engineering and procurement
    - Achieved 73% currently under Lump Sum contract
    - Balance to be bid during 2009
  - Evaluate work by CNQ own forces
    - Next step to improving project execution

Horizon Oil Sands
Phase 2/3 - Development Strategy

- **Established four tranches**
  - Tranche 1: completed $212 million
    - Engineering design specification for 232,000 bbl/d
    - Front end engineering and design
    - Coker foundations and some supporting infrastructure built
    - Long lead equipment ordered
      (coke drums, reactors, mobile equipment)
  - Tranche 2: under development
    - No production loss during first shutdown
      (Third OPP & Hydrotransport)
    - Environmental commitments (Gas Recovery Unit, third Sulphur Plant)
    - Increase reliability “Flood the Upgrader” (mine equipment)
    - Debottlenecking potential production gains of 5% to 15%
Horizon Oil Sands
Phase 2/3 - Development Strategy

- **Tranche 3**
  - Transition to new tailings technology (reduce energy and op costs)
  - Additional mining equipment & shops
  - Coker expansion, CO₂ recovery
  - Production increase by 10,000 to 20,000 bbl/d SCO

- **Tranche 4:**
  - Ore Preparation Plants (trains 4 & 5)
  - Extraction retrofit trains 1 & 2
  - Second Froth Treatment Plant
  - Vacuum Recovery Unit / Diluent Recovery Unit
  - Hydrotreating (2 units)
  - Hydrogen Plant
  - Sulphur Plant (train 4)
  - Cogeneration and Heat Integration
  - Tankage
  - Production expansion to 232,000 to 250,000 bbl/d SCO

Heavy Oil
Keystone Pipeline

- **Transportation**
  - Committed 120,000 bbl/d to the Keystone Pipeline Expansion to USGC for 20 years

- **Mitigates logistical constraints**
  - Narrows heavy oil differential

- **Significantly reduces market risk for incremental production**

- **Alternative routing in the event of pipeline apportionment**

- **Supply**
  - Committed 100,000 bbl/d to major US Gulf Coast refiner for 20 years
Heavy Oil Differentials

Differential Impacted by Logistical Constraints

Canadian Natural Free Cash Flow 2010

All Divisions Generating Free Cash Flow
Canadian Natural Assets

- Heavy crude oil
  - 285,000 bbl/d incremental thermal oil
  - Dominant primary heavy oil position
  - Technology upside
- Natural gas
  - >8,000 potential wells in inventory
  - Strong exposure to shale gas
  - Large land base in western Canada
- International
  - Baobab infill
  - Olowi development
  - South Africa exploration
- Horizon Oil Sands
  - Phase 1 onstream
  - Future - take production to ~500,000 bbl/d
  - Technology upside

Canadian Natural Advantage

- Management, business philosophy, practice
- Strong, balanced assets
  - Vast opportunities
- Balanced, proven, effective strategy
- Control over capital allocation
- Nimble
  - Capture opportunities
  - Willingness to make tough decisions
- Significant free cash flow
- Canadian Natural culture
  - Low cost
  - Execution focused

The Premium Value, Defined Growth Independent
### Revolving Bank Credit Facilities

<table>
<thead>
<tr>
<th></th>
<th>(C$ millions)</th>
<th>Maturity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revolving bank line - Conventional</td>
<td>$2,230</td>
<td>June 2012</td>
</tr>
<tr>
<td>Revolving bank line - Horizon Oil Sands</td>
<td>$1,500</td>
<td>June 2012</td>
</tr>
<tr>
<td>Operating demand loan</td>
<td>$200</td>
<td>Demand</td>
</tr>
<tr>
<td>North Sea operating line (£15 million)</td>
<td>$26</td>
<td>Demand</td>
</tr>
<tr>
<td><strong>Total bank lines</strong></td>
<td><strong>$3,956</strong></td>
<td></td>
</tr>
</tbody>
</table>

**Available - September 30, 2009** $1,261

### Maturity Schedule

**Public Debt**

<table>
<thead>
<tr>
<th>Year</th>
<th>(C$ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>400</td>
</tr>
<tr>
<td>2013</td>
<td>200</td>
</tr>
<tr>
<td>2016</td>
<td>600</td>
</tr>
<tr>
<td>2019</td>
<td>1,200</td>
</tr>
<tr>
<td>2022</td>
<td>800</td>
</tr>
<tr>
<td>2025</td>
<td>1,400</td>
</tr>
<tr>
<td>2028</td>
<td>1,200</td>
</tr>
<tr>
<td>2031</td>
<td>1,000</td>
</tr>
<tr>
<td>2035</td>
<td>800</td>
</tr>
<tr>
<td>2039</td>
<td>1,400</td>
</tr>
</tbody>
</table>

**C$ Public**

- Represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.

**Manageable Refinancing**
2009 Natural Gas Hedging
AECO (C$/GJ)

Note: Refer to quarterly reports for detailed hedging positions. Strip pricing as at Sep 30, 2009.

Upside Opportunity, Downside Protection

2009 Crude Oil Hedging
WTI (US$/bbl)

Note: Refer to quarterly reports for detailed hedging positions. Strip pricing as at Sep 30, 2009.

Upside Opportunity, Downside Protection
Special Note Regarding Currency, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Production data is presented on a before royalties basis unless otherwise stated. In addition, reference is made to oil and gas in common units called barrel of oil equivalent ("boe"). A boe is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead.

Canadian Natural retains qualified independent reserve evaluators to evaluate 100% of the Company’s conventional proved, as well as proved and probable crude oil, natural gas liquids and natural gas reserves and prepares independent Reserve Reports on these reserves. Canadian Natural has been granted an exemption from National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Security and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are three principal differences between the two standards. The first is the lack of proved and probable reserves as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The third is the requirement to disclose a gross reserve reconciliation (before the consideration of royalties). Canadian Natural discloses its reserve reconciliation net of royalties in adherence to SEC requirements.

The Company has disclosed proved conventional reserves and the Standardized Measure of discounted future net cash flows using year-end constant prices and costs as mandated by the SEC. The Company has elected to provide the net present value of these same conventional proved reserves as well as its conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. In addition to the constant price and cost scenario, Canadian Natural has also elected to provide both proved and proved probable conventional reserves and the net present value of these reserves using forecast prices and costs as voluntary additional information.

Special Note Regarding Forward-Looking Statements

Certain statements in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as “forward-looking statements”) within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words “believe”, “anticipate”, “expect”, “plan”, “estimate”, “target”, “continue”, “could”, “intend”, “may”, “potential”, “predict”, “should”, “will”, “objective”, “project”, “forecast”, “goal”, “guidance”, “outlook”, “effort”, “seeks”, “schedule”, “developing future capital for statements regarding an outlook. Statements relating to “reserves” are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurance that the plans, initiatives or expectations upon which they are based will occur.

The forward-looking statements are based on current expectations, estimates and projections about Canadian Natural Resources Limited (the “Company”) and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained and are subject to known and unknown risks, uncertainties and other factors that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company’s current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to maintain its customers, manage its risks, achieve development activities; impact of competition; the Company’s defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete its capital programs; the Company’s and its subsidiaries’ ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company’s bitumen; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour and provide for capital expenditures, as well as operating necessary assets; management’s ability to maintain projected production and sale of crude oil and natural gas; availability and cost of financing; the Company’s and its subsidiaries’ success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, bitumen, natural gas and liquids not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on operating costs); asset retirement obligations; the adequacy of the Company’s provision for taxes; and other circumstances affecting revenues and expenses. Certain of these factors are discussed in more detail under the heading “Risk Factors”. The Company’s operations have been, and at times in the future may be affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available.

Revised are cautioned that the foregoing list of important factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management’s estimates or opinions change.

Special Note Regarding non-GAAP Financial Measures

Management’s discussion and analysis includes references to financial measures commonly used in the crude oil and natural gas industry, such as cash flow from operations, adjusted net earnings from operations, and EBITDA (net earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities). These financial measures are not defined by generally accepted accounting principles (“GAAP”) and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company’s performance.

Volumes shown are Company share before royalties unless otherwise stated.
At September 30, 2009, the Company had the following net derivative financial instruments outstanding to manage its commodity price exposures:

<table>
<thead>
<tr>
<th>Remaining term</th>
<th>Volume</th>
<th>Weighted average price</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Crude oil</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Crude oil price collars (1)</td>
<td>Oct 2009 – Dec 2009</td>
<td>25,000 bbl/d</td>
<td>US$70.00 – US$111.56</td>
</tr>
<tr>
<td></td>
<td>Jan 2010 – Jun 2010</td>
<td>100,000 bbl/d</td>
<td>US$60.00 – US$90.13</td>
</tr>
<tr>
<td></td>
<td>Jan 2010 – Dec 2010</td>
<td>50,000 bbl/d</td>
<td>US$60.00 – US$75.08</td>
</tr>
<tr>
<td>Crude oil puts</td>
<td>Oct 2009 – Dec 2009</td>
<td>92,000 bbl/d</td>
<td>US$100.00</td>
</tr>
</tbody>
</table>

(1) Subsequent to September 30, 2009, the Company entered into 50,000 bbl/d of US$65.00 – US$105.49 WTI collars for the period January to September 2010.

At September 30, 2009, the net cost of outstanding put options to be settled during the fourth quarter of 2009 was US$61 million.

<table>
<thead>
<tr>
<th>Remaining term</th>
<th>Volume</th>
<th>Weighted average price</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Natural gas</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural gas price collars</td>
<td>Jan 2010 – Dec 2010</td>
<td>220,000 GJ/d</td>
<td>C$6.00 – C$8.00</td>
</tr>
</tbody>
</table>

The Company’s outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

There were no commodity derivative financial instruments designated as hedges at September 30, 2009.

In addition to the derivative financial instruments noted above, the Company entered into natural gas physical sales contracts for 400,000 GJ/d at an average fixed price of C$5.29 per GJ at AECO for the period October to December 2009.
## Operational Information

### Daily production, before royalties

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil and NGLs (mbbl/d)</td>
<td>242</td>
<td>283</td>
<td>313</td>
<td>332</td>
<td>331</td>
<td>316</td>
</tr>
<tr>
<td>Natural gas (mmcf/d)</td>
<td>1,299</td>
<td>1,388</td>
<td>1,439</td>
<td>1,492</td>
<td>1,668</td>
<td>1,495</td>
</tr>
<tr>
<td>Barrels of oil equivalent (mboe/d)</td>
<td>459</td>
<td>514</td>
<td>553</td>
<td>581</td>
<td>609</td>
<td>565</td>
</tr>
</tbody>
</table>

### Daily production, after royalties

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil and NGLs (mbbl/d)</td>
<td>220</td>
<td>256</td>
<td>283</td>
<td>301</td>
<td>293</td>
<td>276</td>
</tr>
<tr>
<td>Natural gas (mmcf/d)</td>
<td>1,030</td>
<td>1,105</td>
<td>1,147</td>
<td>1,209</td>
<td>1,402</td>
<td>1,246</td>
</tr>
<tr>
<td>Barrels of oil equivalent (mboe/d)</td>
<td>391</td>
<td>440</td>
<td>474</td>
<td>502</td>
<td>526</td>
<td>484</td>
</tr>
</tbody>
</table>

### Proved reserves, before royalties

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil and NGLs (mmbbl)</td>
<td>1,000</td>
<td>1,123</td>
<td>1,223</td>
<td>1,487</td>
<td>1,543</td>
<td>1,470</td>
</tr>
<tr>
<td>Natural gas (bcf)</td>
<td>3,154</td>
<td>3,310</td>
<td>3,490</td>
<td>4,613</td>
<td>4,435</td>
<td>4,251</td>
</tr>
<tr>
<td>Barrels of oil equivalent (mmboe)</td>
<td>1,526</td>
<td>1,674</td>
<td>1,804</td>
<td>2,256</td>
<td>2,282</td>
<td>2,178</td>
</tr>
</tbody>
</table>

### Proved reserves, after royalties

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil and NGLs (mmbbl)</td>
<td>895</td>
<td>1,066</td>
<td>1,118</td>
<td>1,316</td>
<td>1,358</td>
<td>1,346</td>
</tr>
<tr>
<td>Natural gas (bcf)</td>
<td>2,588</td>
<td>2,690</td>
<td>2,842</td>
<td>3,798</td>
<td>3,666</td>
<td>3,684</td>
</tr>
<tr>
<td>Barrels of oil equivalent (mmboe)</td>
<td>1,320</td>
<td>1,514</td>
<td>1,592</td>
<td>1,949</td>
<td>1,969</td>
<td>1,960</td>
</tr>
</tbody>
</table>

### Drilling activity, net wells

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil and NGLs</td>
<td>458</td>
<td>328</td>
<td>627</td>
<td>603</td>
<td>592</td>
<td>682</td>
</tr>
<tr>
<td>Natural gas</td>
<td>777</td>
<td>689</td>
<td>890</td>
<td>641</td>
<td>383</td>
<td>269</td>
</tr>
<tr>
<td>Dry</td>
<td>118</td>
<td>96</td>
<td>117</td>
<td>119</td>
<td>93</td>
<td>39</td>
</tr>
<tr>
<td>Strats and service</td>
<td>440</td>
<td>336</td>
<td>248</td>
<td>375</td>
<td>254</td>
<td>131</td>
</tr>
</tbody>
</table>

### Undeveloped land (thousands of acres)

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>9,811</td>
<td>11,523</td>
<td>10,947</td>
<td>12,785</td>
<td>12,160</td>
<td>11,603</td>
</tr>
<tr>
<td>North Sea</td>
<td>573</td>
<td>565</td>
<td>352</td>
<td>299</td>
<td>287</td>
<td>258</td>
</tr>
<tr>
<td>Offshore West Africa</td>
<td>943</td>
<td>886</td>
<td>426</td>
<td>207</td>
<td>192</td>
<td>192</td>
</tr>
</tbody>
</table>

### Realized product pricing, before hedging activities & after transportation costs

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil and NGLs (C$/bbl)</td>
<td>32.66</td>
<td>37.99</td>
<td>46.86</td>
<td>53.65</td>
<td>55.45</td>
<td>82.41</td>
</tr>
<tr>
<td>Natural gas (C$/mcf)</td>
<td>6.21</td>
<td>6.50</td>
<td>8.57</td>
<td>6.72</td>
<td>6.85</td>
<td>8.39</td>
</tr>
</tbody>
</table>

### Results of operations (C$ millions, except per share)

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash flow from operations per share</td>
<td>3,160</td>
<td>3,769</td>
<td>5,021</td>
<td>4,932</td>
<td>6,198</td>
<td>6,969</td>
</tr>
<tr>
<td>Net earnings per share</td>
<td>1,403</td>
<td>1,405</td>
<td>1,050</td>
<td>2,524</td>
<td>2,608</td>
<td>4,985</td>
</tr>
<tr>
<td>Capital expenditures (net, including combinations)</td>
<td>2,506</td>
<td>4,633</td>
<td>4,932</td>
<td>12,025</td>
<td>6,425</td>
<td>7,451</td>
</tr>
</tbody>
</table>

### Balance Sheet Info (C$ millions)

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Property, plant and equipment</td>
<td>13,714</td>
<td>17,064</td>
<td>19,694</td>
<td>30,767</td>
<td>33,902</td>
<td>38,966</td>
</tr>
<tr>
<td>Total assets</td>
<td>14,643</td>
<td>18,372</td>
<td>21,852</td>
<td>33,160</td>
<td>36,114</td>
<td>42,650</td>
</tr>
<tr>
<td>Long-term debt</td>
<td>2,748</td>
<td>3,538</td>
<td>3,321</td>
<td>11,043</td>
<td>10,940</td>
<td>12,596</td>
</tr>
<tr>
<td>Shareholders’ equity</td>
<td>6,006</td>
<td>7,324</td>
<td>8,237</td>
<td>10,690</td>
<td>13,321</td>
<td>18,374</td>
</tr>
</tbody>
</table>

### Ratios

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt to cash flow, trailing 12 months</td>
<td>0.9x</td>
<td>1.0x</td>
<td>0.7x</td>
<td>2.2x</td>
<td>1.8x</td>
<td>1.9x</td>
</tr>
<tr>
<td>Debt to book capitalization</td>
<td>33%</td>
<td>34%</td>
<td>29%</td>
<td>51%</td>
<td>45%</td>
<td>41%</td>
</tr>
<tr>
<td>Return to common equity, trailing 12 months</td>
<td>26%</td>
<td>21%</td>
<td>14%</td>
<td>27%</td>
<td>22%</td>
<td>33%</td>
</tr>
<tr>
<td>Daily production before royalties per 10,000 common shares</td>
<td>8.5</td>
<td>9.6</td>
<td>10.3</td>
<td>10.8</td>
<td>11.3</td>
<td>10.4</td>
</tr>
<tr>
<td>Proved and probable reserves before royalties per common share</td>
<td>4.0</td>
<td>4.3</td>
<td>4.8</td>
<td>6.4</td>
<td>6.3</td>
<td>6.1</td>
</tr>
</tbody>
</table>

### Share information

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Common shares outstanding</td>
<td>534,926</td>
<td>536,361</td>
<td>536,348</td>
<td>537,903</td>
<td>539,729</td>
<td>540,991</td>
</tr>
<tr>
<td>Weighted average common shares</td>
<td>536,940</td>
<td>536,223</td>
<td>536,650</td>
<td>537,339</td>
<td>539,336</td>
<td>540,647</td>
</tr>
<tr>
<td>Dividend per share (C$)</td>
<td>0.15</td>
<td>0.20</td>
<td>0.24</td>
<td>0.30</td>
<td>0.34</td>
<td>0.40</td>
</tr>
</tbody>
</table>

### TSX trading info

<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average daily trading volume (thousands)</td>
<td>2,344</td>
<td>2,724</td>
<td>2,542</td>
<td>2,028</td>
<td>1,709</td>
<td>2,708</td>
</tr>
<tr>
<td>High (C$)</td>
<td>16.81</td>
<td>27.58</td>
<td>62.00</td>
<td>73.91</td>
<td>80.02</td>
<td>111.30</td>
</tr>
<tr>
<td>Low (C$)</td>
<td>11.30</td>
<td>15.96</td>
<td>24.28</td>
<td>45.49</td>
<td>52.45</td>
<td>34.19</td>
</tr>
<tr>
<td>Close (C$)</td>
<td>16.34</td>
<td>25.63</td>
<td>57.63</td>
<td>62.15</td>
<td>72.58</td>
<td>48.75</td>
</tr>
</tbody>
</table>

Note: All per share data adjusted for 2004 and 2005 stock splits.
**Fourth Quarter 2009**

### Daily Production Volumes (before royalties)

<table>
<thead>
<tr>
<th>Region</th>
<th>Natural gas (mmcf/d)</th>
<th>Crude oil and NGLs (mbbl/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>North America</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural gas</td>
<td>1,185 - 1,210</td>
<td>225 - 235</td>
</tr>
<tr>
<td>Crude oil and NGLs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conventional</td>
<td></td>
<td></td>
</tr>
<tr>
<td>North America</td>
<td>1,279 - 1,285</td>
<td>233 - 236</td>
</tr>
<tr>
<td>North Sea</td>
<td>10 - 12</td>
<td>70 - 85</td>
</tr>
<tr>
<td>Offshore West Africa</td>
<td>18 - 21</td>
<td>34 - 37</td>
</tr>
</tbody>
</table>

### Capital Expenditures (C$ millions)

**Conventional**

- North America natural gas: $495
- North America crude oil and NGLs: 1,220
- North Sea: 170
- Offshore West Africa: 550
- Property acquisitions, dispositions and midstream: 85

**Horizon Oil Sands Project**

- Phase 1 – Construction: 90
- Phase 1 – Operating inventory, capital inventory and commissioning costs: 200
- Phase 2/3 – Tranche 2: 135
- Sustaining capital: 100
- Capitalized interest and other costs: 75

**Total Capital Expenditures**: $3,120

### Average Annual Cost Data

<table>
<thead>
<tr>
<th>Royalty Rate</th>
<th>Natural Gas - North America (mcf)</th>
<th>Crude oil and NGLs (bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7 - 8%</td>
<td>$1.05 - 1.10</td>
<td>$14.85 - 15.05</td>
</tr>
<tr>
<td>13 - 15%</td>
<td></td>
<td>2 - 3% $35.00 - 45.00</td>
</tr>
<tr>
<td>6 - 9%</td>
<td></td>
<td>12.50 - 13.50</td>
</tr>
</tbody>
</table>

*Royalties are payable on the bitumen production

### Other Information

- **Cash income and other taxes (C$ millions)**
  - Sask. Resources Surcharge/Capital Tax: $20 - 30
  - Current income taxes – North America: $15 - 20
  - Current income taxes – International: $350 - 390
  - Petroleum Revenue Tax (PRT): $65 - 85

- **Effective tax rate on adjusted earnings**: 26% - 30%
- **Depletion, depreciation and ARO accretion charge ($/BOE)**: $13.10 - 13.50
- **Midstream cash flow (C$ millions)**: $40 - 50
- **Average corporate interest rate**: 4.25% - 4.40%

Note: Interest rates are subject to change depending upon short term rate changes. Cash income taxes are subject to variation with commodity prices and the level and classification of capital expenditures. Cash PRT is subject to variation due to commodity price and capital spending. 2009 revised based on an average annual WTI of $62.42/bbl, NYMEX of US$4.17/mmbtu and an exchange rate of US$0.88 to C$1.00.
Allan P. Markin, Chairman

John G. Langille, Vice-Chairman

Steve W. Laut, President & Chief Operating Officer

Douglas A. Proll, Chief Financial Officer & Senior Vice-President, Finance

Corey B. Bieber, Vice-President, Finance & Investor Relations
(403) 517-6878

Mark Stainthorpe, Supervisor, Investor Relations
(403) 514-7845

CANADIAN NATURAL RESOURCES LIMITED
2500, 855 - 2nd Street S.W.,
Calgary, Alberta,
T2P 4J8

Telephone: (403) 514-7777
Facsimile: (403) 514-7888
Email: ir@cnrl.com

WWW.CNRL.COM