Recent developments

On Aug 28/13, announced an agreement to sell New England assets for US$541M and a refocusing of merchant power business on Alberta only

- Transaction expected to close by 2013 year-end
- Sales proceeds redeployed to reduce merchant risk profile and provide more predictable earnings and cash flow
- Merchant and trading activities in Alberta-only; pursue growth in contracted development & acquisition opportunities across North America
- Expect to record $10M restructuring charge in Q3/13
- Net of expected trading margins and excluding sale of New England facilities, annual cost savings of $25-$30M from business refocusing; increase in EPS and CFPS by $0.20-$0.25 and $0.25-$0.30, respectively

Asset divestiture and a refocusing of business is accretive to 2014 financial results
### Overview of Capital Power

**Independent power producer (IPP)**
- Trading on TSX (CPX); ~$2.0B diluted market cap; attractive dividend yield of ~6.0%
- IPO in mid-2009 from spin-off of power generation assets from EPCOR
- EPCOR continues to sell down interest from 72% to 29%

**Straight-forward business model**
- Contracted cash flow base
- Significant contracted and merchant investments in Alberta power market (the most attractive market in North America)
- Alberta merchant upside

**High-quality generation portfolio**
- Young and modern fleet with current generation of more than 3,600 MW
- Average age of 12.5 years
- Current generation focused on natural gas, coal and wind

**Proven operating, construction and trading history**
- 4-year average plant availability of 92%; targeting 93% for 2013
- Significant experience in construction and operation of thermal and renewable wind facilities
- Alberta trading reduces volatility and optimizes cash flow

**Growth initiatives**
- Two Ontario wind projects (Port Dover & Nanticoke, K2 Wind)
- Two Alberta natural gas facilities (Shepard, Capital Power Energy Centre)
- Greenfield development pipeline
- No equity financing requirements

**Financial strength and strong cash flow generation**
- Investment grade credit rating from S&P and DBRS
- 10% CAGR of discretionary cash flow from 2010-12
- Substantial discretionary cash flow
North American footprint
Ownership interest in 12 facilities with more than 2,500 MW\(^{(1)}\)

**Alberta**
1,943 MW of owned generation; future addition of Shepard and CPEC

**BC**
417 MW contracted generation

**Ontario**
- Two contracted wind facilities under development/construction
- 40 MW contracted wind facility

**US Northeast**
- Planned divestiture of 3 gas plants by 2013 year-end

**Mid-Atlantic US**
- Solid fuel assets with 10-year PPAs

---

(1) Based on MW owned capacity as of August 30/13; excludes Sundance PPA (371 MW) and Clover Bar Landfill Gas (4.8 MW); assumes divestiture of three US Northeast assets (1,089 MW).
Alberta market

AB market design expected to continue to provide timely pricing signals for the addition of new supply

Forecast spark spreads above historical average\(^{(1)}\)

Projected reserve margin signals the need for new capacity in the 2017-2020 timeframe\(^{(1)}\)

“Alberta’s future power demand outlook is also fairly robust, especially compared with that of most other jurisdictions in North America, because of a strong provincial economy; a growing population from inward migration; and anticipated high growth in the energy sector, especially for shale gas, tight oil, and oil sands production.”

— (IHS CERA, Sept/12)

\(^{(1)}\) Source: AESO and CPC Estimates - Sept/13
Capital Power’s Alberta fleet
2,355 MWs in 2015

Sundance PPA
• 371 MW owned merchant capacity from low cost baseload coal units 5 & 6

Genesee 1 & 2
• 860 MW low cost baseload coal under PPA until 2020
• 94% availability (2012), 97% (2011)

Genesee 3 & Keephills 3
• 505 MW merchant capacity from jointly-owned & operated plants
• Cleanest coal units in Canada
• Longest average life remaining of 45 years

Joffre Cogen
• 192 MW capacity from jointly-owned mid-merit natural gas combined cycle facility

Shepard Energy Centre
• Under construction for COD in 2015
• 50% JV interest in 800 MW natural gas combined cycle facility
• Most efficient gas facility, with lowest heat rate

Clover Bar Energy Centre
• Most responsive peaking facility in the Alberta market
• 97% availability over trailing 8 quarters
• Captures peak pricing, backstops position

Halkirk Wind
• Largest wind farm in Alberta
• Long-term Renewable Energy Credits into California market
• Unique geographical location provides greater captured price

Well positioned to capture value in Alberta’s merchant market
2015 Alberta power generation stack

(1) Capital Power’s percentages reflect ownership interest.
The best fleet in the fastest growing power market in North America

With investments in Shepard and CPEC facilities, Capital Power will own high-quality baseload, mid-merit, renewable and peaking generation in Alberta providing more flexibility than any other power portfolio in the province.

- Best peaking responsiveness
- Best coal fleet reliability
- Lowest environmental impact and lowest cost
- Most competitive natural gas combined cycle
Focus on contracted margins

- Sale of the US North East assets improves the Contracted operating margin relative to merchant operating margin.
- A focus on merchant operations in Alberta will provide upside as the Alberta supply-demand balance tightens over the longer term.

Contracted vs. Merchant mix

![Graph showing contracted vs. merchant mix from 2013F to 2017F. The graph indicates a fluctuation in the mix ratio with a peak around 2015F and a trough around 2014F. The colors represent merchant operating margin (orange) and Contracted operating margin (teal).]
Modern fleet

Helps keep availability high and reduces risk of unplanned outages

- Average weighted facility age of the current fleet is 12.5 years\(^{(1)}\)
- 2 new wind projects (195 MW) begin commercial operations in 2013 & 2015
- Shepard Energy Centre expected COD Q1/15

![Bar chart showing facility age and remaining life for different energy sources.]

1. Average facility age and remaining life weighted by owned capacity as of September 1/13.
Proven operating excellence

Operating availability consistently 90%+ over a growing fleet and production volumes

Operating performance

<table>
<thead>
<tr>
<th>Year</th>
<th>Generation (GWh)</th>
<th>Average plant availability</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>6,000</td>
<td>96%</td>
</tr>
<tr>
<td>2010</td>
<td>9,000</td>
<td>90%</td>
</tr>
<tr>
<td>2011</td>
<td>12,000</td>
<td>92%</td>
</tr>
<tr>
<td>2012</td>
<td>15,000</td>
<td>91%</td>
</tr>
<tr>
<td>2013E</td>
<td>18,000</td>
<td>93%</td>
</tr>
</tbody>
</table>
Capturing upside from AB power prices

- Hedging positions based primarily on generation from Genesee 3 and Keephills 3 baseload coal plants and output from the Sundance PPA
- Actively trading throughout various time periods to minimize portfolio risks, create incremental value, and reduce volatility

*CPX’s average realized power price has exceeded spot power prices by ~13% on average since Dec 31/09*
Contracted Ontario wind projects

Port Dover & Nanticoke
- 105 MW (Vestas turbines); near Port Dover & Nanticoke, Ontario
- 31 of 58 turbines fully erected, all access roads completed, 99% of foundations completed
- On target for COD in Q4/13; $340M budget

K2 Wind Ontario
- 270 MW (Siemens turbines); southern Ontario
- Equal one-third partnerships with Samsung and Pattern Renewable Holdings
- REA received July/13; COD targeted for 2015
- $291M capex budget (Capital Power’s portion)
- Project financing to fund primary capital requirements

Both projects have 20-year PPAs with Ontario Power Authority
Shepard Energy Centre
Excellent fit with our strategy, strengthens our position in Alberta, provides stable cash flows

- 20-year tolling agreement on 50% of owned capacity with ENMAX
- Additional 25% contracted for 2015-17 which increases cash flow certainty during an expected period of low pool prices in Alberta
- Additional cash flow certainty created by hedging Capital Power’s existing portfolio by 100 MW in 2013, 300 MW in 2014 and 100 MW in 2015
- $860M capex budget (Capital Power’s portion)
- Will add the most efficient natural gas power production to the province
Capital Power Energy Centre

Actively following process to build a large (up to 900 MW) gas-fired power generation facility in the 2018-2020 timeframe to meet AB’s power needs

- Expect to finalize and announce a partnership agreement for the project in Q4/13 and file an application with Alberta Utilities Commission (AUC) before the end of 2013
- Approval from the AUC expected to be received in the first half of 2015
- Full notice to proceed expected anytime after AUC approval up to the end of Q2/16, depending on expected commercial operating date chosen
- Currently reviewing various gas turbine technologies to determine the best fit for the AB market
- To be built on a site near our Genesee facility west of Edmonton, which has existing infrastructure, utilities and close proximity to gas pipelines and transmission
Financial strength and access to capital

**Strong balance sheet**

- Assets of ~$5.1B with ~$1.6B of third party debt
- $1.2B in credit facilities, of which ~$0.9B available
  - In 2012 added $300M accordion feature

**Debt to total capitalization**

<table>
<thead>
<tr>
<th>Year</th>
<th>Debt to Capitalization</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011(2)</td>
<td>36%</td>
</tr>
<tr>
<td>2012</td>
<td>38%</td>
</tr>
<tr>
<td>2013E</td>
<td>34%</td>
</tr>
</tbody>
</table>

Long-term target: 40% - 50%

(1) Values as of Dec 31, 2012
(2) CPILP accounted for on an equity basis.
Debt maturity schedule

Well spread-out debt maturities are supported by long asset lives

- Term on credit facilities extended to 5 years

(1) As of Dec 31, 2012.
Investments in contracted wind will generate significant incremental cash flow

- 487 MW of owned generation in four wind projects forecast to provide $150M - $155M in annual cash flow before financing
- Strong accretion of ~$0.90 - $0.95 in cash flow per share, and ~$0.35 - $0.40 in earnings per share
Continued strong cash flow generation

Funds From Operations (FFO)

- Expect to exceed target of $385M-$415M in FFO in 2013
- 35-40% of 2010-12 FFO is discretionary cash flow\(^{(1)}\)
- Additional cash flows in 2013 from:
  - Full year operations from Halkirk and Quality Wind
  - PD&N expected COD in Q4/13

\[^{(1)}\] Discretionary cash flow is a non-GAAP financial measure.
### Development projects - capex

<table>
<thead>
<tr>
<th></th>
<th>Prior to 2013</th>
<th>2013E</th>
<th>Project Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Port Dover &amp; Nanticoke</td>
<td>$68</td>
<td>$272</td>
<td>$340</td>
</tr>
<tr>
<td>K2 Wind Ontario</td>
<td>$3</td>
<td>$30</td>
<td>$291&lt;sup&gt;(1)&lt;/sup&gt;</td>
</tr>
<tr>
<td>Shepard Centre</td>
<td>$50</td>
<td>$335</td>
<td>$860</td>
</tr>
</tbody>
</table>

$121 $637 $1,491

**Continue strong execution of capex program**

(1) Represents Capital Power’s portion of total project including project financing.
# Cash flow and financing outlook

No primary common share equity required in 2013 other than via DRIP

## Sources of cash flow ($M) 2013E

<table>
<thead>
<tr>
<th>Source</th>
<th>2013E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Funds from operations</td>
<td>$400</td>
</tr>
<tr>
<td>Preferred share offering (Closed Mar/13)</td>
<td>$200</td>
</tr>
<tr>
<td>Net proceeds from sale of US Northeast assets</td>
<td>~$560</td>
</tr>
</tbody>
</table>

## Uses of cash flow

<table>
<thead>
<tr>
<th>Use</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dividends (net of DRIP) &amp; distributions to NCI</td>
<td>$100</td>
</tr>
<tr>
<td>Dividends (Preferred shares)</td>
<td>$20</td>
</tr>
<tr>
<td>Development projects</td>
<td>$635</td>
</tr>
<tr>
<td>Sustaining capex</td>
<td>$100</td>
</tr>
</tbody>
</table>

## Net change in cash

~$305

- Final tranche payment for investment in Shepard due in early Q1/14 with early payment provision
- Expect Shepard, PD&N and K2 construction costs to be financed by New England transaction proceeds, cash from operations and modest debt

---

(1) Represents mid-point of guidance range.
## Financial performance – Q2 YTD

<table>
<thead>
<tr>
<th>$M, except per share amounts</th>
<th>YTD 2013</th>
<th>YTD 2012</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenues and other income</td>
<td>$686</td>
<td>$637</td>
<td>7.7%</td>
</tr>
<tr>
<td>Adjusted EBITDA(^{(1)})</td>
<td>$231</td>
<td>$212</td>
<td>9.0%</td>
</tr>
<tr>
<td>Basic earnings per share</td>
<td>$0.64</td>
<td>$0.08</td>
<td>-</td>
</tr>
<tr>
<td>Normalized earnings per share</td>
<td>$0.60</td>
<td>$0.50</td>
<td>20%</td>
</tr>
<tr>
<td>Funds from operations</td>
<td>$188</td>
<td>$170</td>
<td>11%</td>
</tr>
<tr>
<td>Cash flow per share</td>
<td>$1.90</td>
<td>$1.74</td>
<td>9.2%</td>
</tr>
</tbody>
</table>

**Positive Q2 year-to-date results ahead of expectations**

\(^{(1)}\) Before unrealized changes in fair value of energy derivative instruments and Atlantic Power shares for Q2/13 YTD and Q2/12 YTD of $8M and $5M, respectively.
AB commercial portfolio positions

- Alberta portfolio hedged positions for AB baseload plants and acquired Sundance PPA (% sold forward)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Percentage sold forward</td>
<td>63%</td>
<td>87%</td>
</tr>
<tr>
<td>Average contracted prices(1) ($/MWh)</td>
<td>Low-$60</td>
<td>High-$50</td>
</tr>
</tbody>
</table>

- Sensitivity analysis to +/- $1/MWh change in Alberta power prices
  - 2013: +/- $2M to adjusted EBITDA

\(1\) The forecast average contracted prices may differ significantly from the future average realized prices as the hedged and unhedged positions have a varying mix of differently priced blocks of power. This impact is accentuated in 2014 which includes one contract-for-differences for 300 MW for the full year that is sold forward for peak periods only.
Based on positive 6-month results and AB power price forecast of ~$75/MWh for the balance of the year, expect full year 2013 financial results to exceed annual guidance of $1.20 to $1.40 for NEPS and $3.80 to $4.20 for cash flow per share.

(1) All financial measures are non-GAAP measures.
Summary

- Straight forward business model – strong base of contracted cash flows and merchant upside from the Alberta power market
- High quality, young and modern generation portfolio
  - Near-term growth of 595 MW of owned capacity from wind projects and natural gas facility
- Substantial Alberta power producer with increasing exposure to the fastest growing power market in North America
- Strong cash flow generation
  - Financial strength with access to capital
  - Investment grade credit rating
Alberta power market

- Alberta (AB) has a competitive wholesale energy and ancillary services market operated by the Alberta Electric System Operator (AESO); market has an installed generation capacity of ~13,000 MW

- No capacity market – power generators must recover all costs through revenue earned in AB’s energy and ancillary services market

- Entire province is a single zone where power prices are determined by the bid price of the incremental power generator (i.e. one with the highest accepted bid sets hourly price) that is dispatched to balance demand and supply in real-time

- AB’s economy expected to grow above national average rate due to the impact of continued oil sands development activities that is a fundamental driver to increasing power demand

- AESO forecasts average annual demand to grow by 4.3% for the next five years (1)

- AB Government announced in Jan/13, that it will continue with the Regulated Rate Option (RRO) and extend the procurement window to 120 days

Alberta generation and load mix

2011 AB fuel mix by capacity (MW)

- Coal 45%
- NG Cogen 28%
- NG CC 5%
- Other 2%
- Wind 6%
- Hydro 6%
- Bio/Wood/Waste/LDF Gas 2%

Source: AESO 2012 Long Term Outlook

Estimated 2011 customer electricity usage including oil sands

- Industrial 46%
- Residential 13%
- Commercial 20%
- Oilsands 18%
- Farm 3%

Source: AESO, Alberta Utilities Commission

- Residential 66% on RRO
- Commercial 50% on RRO
- Farm 74% on RRO
Historical Alberta prices

Daily average power prices

Annual average power prices and AECO

Appendix
Alberta market design

Current market design has been successful in signaling when new capacity is required

Alberta reserve margin and new capacity

- New capacity
- AESO's historical reserve margin
Expected coal unit retirements - CST
Retirements under the federal Capital Stock Turnover (CST) regulations

Alberta coal generation (MW)

<table>
<thead>
<tr>
<th>Facility</th>
<th>Generation Capacity (MW)</th>
<th>End of Life (Final Regulations)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battle River 3</td>
<td>149</td>
<td>2019</td>
</tr>
<tr>
<td>Sundance 1</td>
<td>288</td>
<td>2019</td>
</tr>
<tr>
<td>H.R. Milner</td>
<td>144</td>
<td>2019</td>
</tr>
<tr>
<td>Sundance 2</td>
<td>288</td>
<td>2019</td>
</tr>
<tr>
<td>Battle River 4</td>
<td>155</td>
<td>2025</td>
</tr>
<tr>
<td>Sundance 3</td>
<td>362</td>
<td>2026</td>
</tr>
<tr>
<td>Sundance 4</td>
<td>406</td>
<td>2027</td>
</tr>
<tr>
<td>Sundance 5(1)</td>
<td>406</td>
<td>2028</td>
</tr>
<tr>
<td>Sundance 6(1)</td>
<td>401</td>
<td>2029</td>
</tr>
<tr>
<td>Battle River 5</td>
<td>385</td>
<td>2029</td>
</tr>
<tr>
<td>Keephills 1</td>
<td>387</td>
<td>2029</td>
</tr>
<tr>
<td>Keephills 2</td>
<td>406</td>
<td>2029</td>
</tr>
<tr>
<td>Sheerness 1</td>
<td>390</td>
<td>2036</td>
</tr>
<tr>
<td>Genesee 2(1)</td>
<td>430</td>
<td>2039</td>
</tr>
<tr>
<td>Sheerness 2</td>
<td>390</td>
<td>2040</td>
</tr>
<tr>
<td>Genesee 1(1)</td>
<td>430</td>
<td>2044</td>
</tr>
<tr>
<td>Genesee 3(1)</td>
<td>516</td>
<td>2055</td>
</tr>
<tr>
<td>Keephills 3(1)</td>
<td>466</td>
<td>2061</td>
</tr>
</tbody>
</table>

(1) Represents units that Capital Power has ownership/interests in.
Clean Air Strategic Alliance (CASA) regulations may result in coal units retiring sooner.

**2019:** Sundance 1&2 (576 MW); Battle River 3 (149 MW)

**2025-29:** Sundance 3-6 (1,575 MW); Battle River 4&5 (540 MW)

**NOTE:** CASA Financial Compliance assumes coal-fired capacity retirements in the year BATEA must be installed as per the Alberta Air Emissions Standards for Electricity Generation CASA framework.
Alberta power market summary

Alberta’s market design framework

- Has attracted continued investment by various parties for different fuel types
- Ensures investment risk is borne by investors and not ratepayers/taxpayers
- Provides participants with options and choices for managing their commodity price risk

Capital Power believes Alberta’s market design is sustainable and will continue to attract investment

- No major market reforms required
- Effective implementation of existing policy directives, particularly new transmission development

“…analysis confirms that, from a resource adequacy and generation investment perspective, the Alberta electricity market is generally well functioning based on current market conditions and policies. The current market design should be able to address the identified resource adequacy challenges and there is no compelling or immediate need for major design changes to address these challenges.”

— (The Brattle Group, Inc., Mar/13)
## Summary of assets

<table>
<thead>
<tr>
<th></th>
<th>Genesee 1</th>
<th>Genesee 2</th>
<th>Genesee 3</th>
<th>Keephills 3</th>
<th>Joffre</th>
<th>Clover Bar Energy Centre</th>
<th>Clover Bar Landfill</th>
<th>Halkirk</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capacity</strong></td>
<td>430 MW</td>
<td>430 MW</td>
<td>516 MW</td>
<td>495 MW</td>
<td>480 MW</td>
<td>243 MW</td>
<td>4.8 MW</td>
<td>150 MW</td>
</tr>
<tr>
<td><strong>% owned / operated</strong></td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>50 / 100</td>
<td>50 / 0</td>
<td>40 / 0</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
</tr>
<tr>
<td><strong>Location</strong></td>
<td>Warburg, Alberta</td>
<td>Warburg, Alberta</td>
<td>Warburg, Alberta</td>
<td>Keephills, Alberta</td>
<td>Joffre, Alberta</td>
<td>Edmonton, Alberta</td>
<td>Edmonton, Alberta</td>
<td>Halkirk, Alberta</td>
</tr>
<tr>
<td><strong>Fuel &amp; equipment</strong></td>
<td>Coal (50% ownership of coal mine)</td>
<td>Coal (50% ownership of coal mine)</td>
<td>Coal (50% ownership of coal mine)</td>
<td>Coal</td>
<td>Natural gas</td>
<td>Natural gas (Two 100 MW GE LMS100 turbines; 43 MW GE LM6000)</td>
<td>Landfill gas</td>
<td>Vestas wind turbines</td>
</tr>
<tr>
<td><strong>PPA Expiry</strong></td>
<td>2020</td>
<td>2020</td>
<td>Merchant</td>
<td>Merchant</td>
<td>Merchant</td>
<td>Merchant</td>
<td>Merchant</td>
<td>~40% - 45% of total revenues from 20-year REC sale agreement / Merchant</td>
</tr>
</tbody>
</table>
# Summary of assets (cont’d)

<table>
<thead>
<tr>
<th>Location</th>
<th>Kingsbridge Island Generation</th>
<th>Quality Wind</th>
<th>Roxboro</th>
<th>Southport</th>
<th>Tiverton</th>
<th>Rumford</th>
<th>Bridgeport</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ontario &amp; British Columbia Contracted</td>
<td>40 MW</td>
<td>275 MW</td>
<td>142 MW</td>
<td>88 MW</td>
<td>46 MW</td>
<td>279 MW(1)</td>
<td>270 MW(1)</td>
</tr>
<tr>
<td>Mid-Atlantic Contracted</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
</tr>
<tr>
<td>US Northeast Commercial</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
</tr>
<tr>
<td>Capacity</td>
<td>40 MW</td>
<td>275 MW</td>
<td>142 MW</td>
<td>88 MW</td>
<td>46 MW</td>
<td>279 MW(1)</td>
<td>270 MW(1)</td>
</tr>
<tr>
<td>% owned / operated</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
<td>100 / 100</td>
</tr>
<tr>
<td>Location</td>
<td>Goderich, Ontario</td>
<td>Campbell River, BC</td>
<td>Near Tumbler Ridge, BC</td>
<td>Roxboro, North Carolina</td>
<td>Southport, North Carolina</td>
<td>Tiverton, Rhode Island</td>
<td>Rumford, Maine</td>
</tr>
<tr>
<td>Fuel &amp; equipment</td>
<td>Vestas wind turbines</td>
<td>Natural gas (Alstom GT24B gas turbine &amp; Alstom steam turbine)</td>
<td>Vestas wind turbines</td>
<td>Mixture of wood residuals, tire-derived fuel and coal</td>
<td>Mixture of wood residuals, tire-derived fuel and coal</td>
<td>Natural gas</td>
<td>Natural gas</td>
</tr>
<tr>
<td>PPA Expiry</td>
<td>2026 / 2027</td>
<td>2022</td>
<td>2037</td>
<td>2021</td>
<td>2021</td>
<td>Merchant</td>
<td>Merchant</td>
</tr>
</tbody>
</table>

(1) Represents net winter capacity. Tiverton, Rumford and Bridgeport have nominal generation capacities of 265, 265, and 520 megawatts, respectively.
## Development projects

<table>
<thead>
<tr>
<th>Shepard Energy Centre</th>
<th>Capital Power Energy Centre</th>
<th>K2 Wind Ontario</th>
<th>Port Dover &amp; Nanticoke</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capacity</strong></td>
<td>800 MW</td>
<td>Up to 900 MW</td>
<td>270 MW</td>
</tr>
<tr>
<td><strong>% owned / operated</strong></td>
<td>50 / 0</td>
<td>100 / 100, looking for 3rd party in development</td>
<td>33.3% owned</td>
</tr>
<tr>
<td><strong>Location</strong></td>
<td>Calgary, Alberta</td>
<td>Warburg, Alberta</td>
<td>Ashfield-Colborne-Wawanosh, Ontario</td>
</tr>
<tr>
<td><strong>Fuel &amp; equipment</strong></td>
<td>Combined-cycle natural gas; 6,900 – 7,100 mmbtu (effective heat rate)</td>
<td>Combined-cycle natural gas</td>
<td>Siemens wind turbines</td>
</tr>
<tr>
<td><strong>Commercial Operations</strong></td>
<td>Expected Q1/15</td>
<td>Targeting 2018-2020</td>
<td>Expected 2015</td>
</tr>
<tr>
<td><strong>PPA Expiry</strong></td>
<td>Merchant / 75% of CPC’s share of the project output under 20-year tolling arrangement for the 2015-17 period and 50% thereafter until 2035.</td>
<td>Merchant</td>
<td>20-year PPA with Ontario Power Authority for $135/MWh</td>
</tr>
<tr>
<td><strong>Expected Capital Cost</strong></td>
<td>$855M CPC’s expected total cost (Estimated total project cost $1.6B)</td>
<td>$291M CPC’s expected capex including project financing ($874M expected total project capex)</td>
<td>$340M</td>
</tr>
</tbody>
</table>
Non-GAAP financial measures

The Company uses (i) earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses, and gains on disposals (adjusted EBITDA), (ii) funds from operations, (iii) cash flow per share, (iv) discretionary cash flow, (v) normalized earnings attributable to common shareholders, and (vi) normalized earnings per share as financial performance measures.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and are therefore unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to Shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company’s results of operations from management’s perspective.

Reconciliations of these Non-GAAP financial measures are contained in the Company’s Management’s Discussion and Analysis dated July 26, 2013 for the six months ended June 30, 2013 which is available under the Company’s profile on SEDAR at www.SEDAR.com and on the Company’s website at www.capitalpower.com.
Forward-looking information or statements included in this presentation are provided to inform the Company’s shareholders and potential investors about management’s assessment of Capital Power’s future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this presentation is generally identified by words such as “will”, “anticipate”, “believe”, “plan”, “intend”, “target”, and “expect” or similar words that suggest future outcomes.

Material forward-looking information in this presentation includes information with respect to: (i) expectations related to future earnings and funds from operations, (ii) expectations regarding the future pricing of electricity and market fundamentals in existing and target markets, (iii) expectations regarding fuel supply and pricing, (iv) expectations related to the Company’s future cash requirements including interest and principal repayments, capital expenditures and dividends, (v) expectations for the Company’s sources of funding, adequacy and availability of committed bank credit facilities and future borrowings, (vi) expectations regarding future growth and emerging opportunities in the Company’s target markets including the focus on certain technologies, (vii) expectations regarding the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions, (viii) expectations regarding plant availability, and (ix) expectations regarding capital expenditures for plant maintenance and other.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments, and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity and other energy prices, (ii) performance, (iii) business prospects and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates, and (vi) other matters discussed under the Performance Overview and Outlook sections of the Company’s second quarter 2013 MD&A dated July 26, 2013.

Whether actual results, performance or achievements will conform to the Company’s expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company’s expectations. Such material risks and uncertainties are: (i) changes in electricity prices in markets in which the Company operates, (ii) changes in energy commodity market prices and use of derivatives, (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) power plant availability and performance including maintenance expenditures, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management in the Company’s December 31, 2012 annual MD&A for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company’s expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.
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