Energy 50 (2013) 93–102

Contents lists available at SciVerse ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

The potential of wind energy to largely displace existing Canadian fossil fuel and nuclear electricity generation

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ARTICLE INFO

Article history:
Received 3 June 2012
Received in revised form
28 November 2012
Accepted 2 December 2012
Available online 16 January 2013

Keywords:
Wind energy
Canada
Displacing fossil fuel and nuclear electricity

ABSTRACT

The potential of wind-generated electricity to displace existing fossil fuel and nuclear generation in Canada is assessed by combining wind turbine power curves with data from the Canadian Wind Energy Atlas. There are many widely-scattered regions with capacity factors (average power output as a fraction of the rated output) greater than 0.4, and some greater than 0.5, that could supply many times the current electricity production from fossil fuel and nuclear powerplants in Canada. By linking multiple high-wind regions to the major demand centres with high voltage direct current transmission lines, the variation in the aggregate electricity output at time scales of one week or less would be greatly reduced, while variations at longer time scales can be largely offset through anti-phase operation of hydro-electric reservoirs. Assuming onshore and offshore wind farm capital costs of about $2000/kW and $3000/kW, respectively, onshore and offshore transmission line costs of $0.5/kW/km and $0.75/kW/km, respectively, and terminal costs of $250/kW, the cost of electricity (financed at a real interest rate of 3%/yr) is 5–7 cents/kWh, which is less than the likely cost of electricity from new coal powerplants equipped to capture CO_2 (at least 9 cents/kWh) or from new nuclear powerplants (10–23 cents/kWh).

1. Introduction

There is a strong scientific consensus that continued emissions of greenhouse gases and associated warming of the global climate poses serious risks to the well-being of human societies and ecosystems worldwide [1–3]. The atmospheric CO_2 concentration has increased from 280 ppmv prior to the industrial revolution to 392 ppmv by 2011 (a 40% increase), while other greenhouse gases have also increased in concentration due to human activities, resulting in the heat-trapping equivalent of a 70–90% increase in CO_2 concentration already (see Table 2.12 of [4]). There is comprehensive, widespread, independent evidence that the eventual global mean warming for an initial doubling of atmospheric CO_2 concentration is 1.5–4.5 °C, but that positive feedbacks between climate and the carbon cycle could result in the release of further CO_2 and of CH_4 that may ultimately increase the warming by a further 25–100% [5]. Warming of only 2–3 °C would have serious impacts on water resources and food production in many regions, and catastrophic effects on many important ecosystems worldwide [6]. The last time that the global mean climate was a mere 1 °C warmer than pre-industrial (during the previous interglacial period, about 120,000 years ago), sea level is estimated to have been 6.6–9.4 m higher than at present [7], while the last time the global mean climate was 2–3 °C warmer (during the early Pliocene, 5–6 million years ago), sea level was likely 15 m higher than present according to a recent estimate [8]. Clearly, large and rapid reductions in emissions of CO_2 and other greenhouse gases are required on a worldwide basis if these risks are to be significantly reduced, with near elimination of fossil fuel CO_2 emissions within this century. As the generation of electricity from fossil fuels accounts for about 25% of current global greenhouse emissions [9], near elimination of electricity-related emissions will require massive deployment of renewable-based electricity generation combined with a strong emphasis on efficient use of electricity so as to limit the future growth in electricity demand.

The European Wind Energy Association [10] and the German Aerospace Center [11] have drawn up scenarios whereby large, widely dispersed wind farms along with concentrating solar thermal powerplants in southern Europe and North Africa, biomass and geothermal powerplants, and hydro-electric power could supply 80% of Europe's entire electricity demand in 2050, while the National Renewable Energy Laboratory in the US [12] assessed how wind could supply 20% of the entire US electricity demand by 2030. Studies focussing on the US and Europe have examined the extent

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0360-5442/$ – see front matter
http://dx.doi.org/10.1016/j.energy.2012.12.008

to which the interconnection of large, geographically dispersed wind farms could reduce the variability in aggregate electrical power output. In particular, Czisch and Giebel [13] show that 6-h variability in wind energy output is reduced by about 30% when considering wind farms distributed across Europe vs in Denmark and Germany only, and is reduced by about 60% when a broader region is considered. Drake and Hubacek [14] find that when wind farms are spread across the UK, the variance in output is reduced by 36% compared to that of a single wind farm, while Dvorak et al. [15] show that the power-duration curve is considerably flattened for a group of 4 offshore wind farms along the US northeast coast compared to that for a single wind farm.

Another strategy to increase the reliability of wind-generated electricity is to deliberately oversize a wind farm relative to the transmission link [16]. The idea is based on the observation that wind speed is rarely strong enough to produce even half the rated power output of a turbine. Thus, a wind farm could be doubled in size (for example) with no increase in the transmission link, and very little potential electricity production would be wasted. Lew et al. (1998) [17] applied this concept to the delivery of electricity from wind farms in Inner Mongolia (which has a good wind resource) to distant demand centres in China, while DeCarolis and Keith [18] have applied it to power production in the central plains of the US. Although oversizing and the associated waste of some generation potential increases the unit cost of generating electricity, this is partly compensated by a decrease in the unit cost of transmitting electricity due to the greater average utilization of the transmission link. This tradeoff will be more favourable the greater the transmission cost relative to the wind farm cost, but will be less favourable the better the wind regime (because oversizing will result in greater wasted potential), although absolute overall costs (with or without oversizing) will be lower with better wind regimes.

To date, there have been no studies of the potential of large, widely distributed wind farms in Canada to reduce the variability of electricity output through partial cancellation of local variations in wind, nor of the potential of oversized wind farms to increase the reliability of wind electricity supply. As will be shown here, the total wind energy resource available in Canada is equivalent to many times current total electricity demand in Canada, and Canada has a large existing hydro-electric generation and energy storage capacity, but to date there has been no assessment of the size and distribution of wind farms that would be needed to completely displace all existing fossil fuel electricity production in Canada and of the associated needs for storage at hourly, daily, and seasonal time scales. This paper is a first step in that direction. In particular, use is made of the Canadian Wind Energy Atlas (CWEA) to assess the cost of generating electricity at each grid cell within a restricted domain of interest, and the cost of transmitting electricity from each grid cell in the domain of interest to each of nine major demand centres in Canada is estimated. Barring other restrictions that are explained later, each allowed grid cell is filled with wind turbines at a spacing equal to seven times the rotor diameter. From there, the least-cost combination of grid cells that is sufficient to generate an amount of electricity equal to the 2007 annual electricity supplied to each of the nine demand centres from fossil fuel and nuclear powerplants is determined. The seasonal variation of wind electricity supply from this least-cost wind farm distribution is then determined, followed by an assessment of the implications for cost and seasonal variation in electricity production of deliberately oversizing the wind farms by a factor of two relative to the transmission links and of using alternative criteria for selecting the specific turbine model to be used in a given grid cell.

Both onshore and offshore wind farms are considered. In shallow lakes, such as Lake Erie (20–25 m depth in the western portion), offshore wind turbines could be mounted directly into the lake bed. A number of floating wind turbine concepts are under development, some prototypes have been tested at sea, and ambitious plans involving several large floating wind farms in the North Sea are being developed [[19], Section 3.10.3; [20,21]].

2. Methods

2.1. Wind speed data

The CWEA provides statistical properties of wind speed at heights of 30 m, 50 m, and 80 m for four seasons (Dec-Jan-Feb (DJF), Mar-Apr-May (MAM), June-Jul-Aug (JJA), and Sep-Oct-Nov (SON)) and in the annual mean on an approximately 4.5 km × 4.5 km grid covering all of Canada and adjacent offshore regions, using a statistical–dynamical procedure based on [22] for downscaling from the NCAR/NCEP reanalysis dataset [23]. The statistical properties of wind speed U are commonly represented by Weibull probability distribution function (PDF), which is how they are represented in the CWEA. This PDF depends on only two parameters, the scale factor (c) and the shape parameter (k), and is given by

$$f(U) = \frac{k}{c}\left(\frac{U}{c}\right)^{k-1}\exp\left[-\left(\frac{U}{c}\right)^{k}\right] \quad (1)$$

Fig. S1 in the Online Supplement shows the Weibull distribution functions for two representative combinations of c and k.

2.2. Computation of mean wind speed and turbine power output

The variation of power output from a wind turbine with wind speed, P_T (U), is referred to as the wind turbine *power curve*. A representative power curve is shown in Fig. S1. The mean wind speed $\overline{U}$ and turbine power output $\overline{P_T}$ are given by

$$\overline{U} = \int_0^\infty f(U)U\mathrm{d}U \approx \sum_{i=1}^{N} f(U_i)U_i\Delta U_i \quad (2)$$

and

$$\overline{P_T} = \int_0^\infty f(U)P_T(U)\mathrm{d}U \approx \sum_{i=1}^{N} f(U_i)P_T(U_i)\Delta U_i \quad (3)$$

respectively, where N is the number of wind speed intervals, ΔU_i is the width of the interval i, and U_i is the wind speed in the middle of interval i.

The highest CWEA data pertain to winds at a height of 80 m. However, the appropriate wind speed for calculating turbine power output is the wind speed at the turbine hub height, which generally ranges from 0.8 to 1.2 times the rotor diameter. Wind speed is often assumed to vary with height according to a power relationship. That is,

$$\frac{U_H}{U_{\mathrm{ref}}} = \left(\frac{H}{h_{\mathrm{ref}}}\right)^n \quad (4)$$

where U_H is the unknown wind speed at height H, U_{ref} is the measured (or simulated) wind speed at the reference height h_{ref} (80 m here) and n is called the *shear factor* and can be estimated from the observed (or simulated) variation of wind speed with height up to h_{ref}. Based on [24], I have chosen $n = 0.11$ for offshore grid cells and $n = 0.18$ for onshore grid cells.

So as to be able to compute turbine power output at any wind speed, polynomials are fitted to the power curves for each wind turbine (one polynomial below the inflexion point in the power curve, another one above the inflexion point). The mean wind speed and power output are computed as

$$\overline{U} = \sum_{i=1}^{N} f(U_i) U_{a-i} \Delta U_i \tag{5}$$

and

$$\overline{P_T} = \sum_{i=1}^{N} f(U_i) p_T(U_{a-i}) \Delta U_i \tag{6}$$

respectively, where U_{a-i} is the adjusted wind speed in interval i and $p_T(U_{a-i})$ is the polynomial fit to turbine power output as a function of U_{a-i}. Through Eqs. (5) and (6), the probability bins for 80 m winds are applied to the corresponding wind speeds at the hub height for each turbine considered.

The power output of a wind turbine at any given wind speed is the product of the wind power density, the area A swept by the rotor, and the turbine efficiency η. The power density of the wind, P_W, is given by

$$P_W = \frac{1}{2} \rho U^3, \tag{7}$$

where ρ is air density and is a function of air temperature T and pressure P, given by

$$\rho = \rho_{\mathrm{ref}} \left(\frac{288.15\ \mathrm{K}}{T + 273.15\ \mathrm{K}} \right) \left(\frac{P}{101.325\ \mathrm{kPa}} \right), \tag{8}$$

where $\rho_{\mathrm{ref}} = 1.225\ \mathrm{kg/m^3}$ is a reference density corresponding to a temperature of 10 °C and a pressure of 101.325 kPa. Thus, electrical output P_E is given by

$$P_E = \frac{1}{2} \eta \rho U^3 A \tag{9}$$

Eq. (9) suggests that the turbine power output should vary in proportion to the air density, but this would be true only if the turbine efficiency is constant as density varies. A more cautious approach is to assume that a change in air density changes the effective wind speed that can be used in the polynomial fit for the power curves, where the effective wind speed is given by

$$U_{\mathrm{eff}} = \left(\frac{\rho}{\rho_{\mathrm{ref}}} \right)^{1/3} U \tag{10}$$

Here, ρ is computed for each season and grid point using climatological seasonal mean surface pressures and surface air temperatures (we used climatological monthly surface pressures from the NCAR dataset at the Lamont Doherty Earth Observatory archive [25] and climatological monthly surface air temperature from the IPCC Data Distribution Centre [26]).

Another factor that needs to be taken into account is the wake effect – the effect of upstream wind turbines in slowing down the wind seen by downstream wind turbines in a wind farm. Calculations by de Prada Gill et al. [27] indicate that for rows of wind turbines placed 7 rotor diameters apart in the downwind direction, the wind speed seen by the second row is about 88% that seen by the first, the wind speed seen by the 3rd row is about 86% that seen by the first, and the remaining rows see about 84% of the wind speed seen by the first row. As we envisage large wind farm arrays here, we will assume that the average wind speed seen by the wind turbines is 85% of the unperturbed wind speed. Finally, it is assumed the energy losses due to soiling of blades and imperfect tracking of the wind direction by the yaw mechanism (given as 1–2% and 1% by [28]) reduce the effective wind speed by 2.5%.

Thus, the adjusted wind speed used in the polynomial fits to $P_T(U)$ are given by

$$U_{a-i} = 0.975 \times 0.85 \left(\frac{\rho}{\rho_{\mathrm{ref}}} \right)^{1/3} \left(\frac{H}{h_{\mathrm{ref}}} \right)^{n} U_{\mathrm{ref}} \tag{11}$$

Assuming that the grid-scale mean wind speeds from the Canadian Wind Energy Atlas are accurate, the above procedure is likely to underestimate the grid-scale wind energy potential in cells with low average wind speeds, and possibly overestimate it in cells with high average wind speeds. This is due to the sub-grid scale variability in wind speed that exists in at any given time, combined with the non-linear relationship between wind speed and turbine electricity output.

2.3. Analysis domain

The CWEA data are on a grid with approximate dimensions of 4.5 km × 4.5 km. Here, all grid cells in the CWEA are considered that are north of the US–Canada border, south of 55°N (56° in the prairie provinces), and within a few hundred km of the ocean coasts, except for the following:

- all cells classified as predominately urban, wetland, or snow or ice (using the 250 m resolution land cover dataset available through the *North American Commission on Environmental Cooperation* [29])
- all offshore cells where the cell centre is within 10 km of the centre of a land grid cell (so that offshore turbines are not located within about 6 km of the coast)
- all cells where the average elevation is greater than 1600 m (so as to prevent placement of turbines in the Rocky Mountains).

As well, only the fraction of each remaining grid cell where the slope is less than 18% is assumed to be suitable for wind turbines. Slopes and elevations on a 100 m horizontal grid were computed from the *Canadian Digital Elevation Data 1:250,000* dataset, available through *Geobase* [30], and the proportion of a sample centred at each CWEA grid point with a slope less than 18% was determined. The original domain contains 243,782 grid cells, of which 11,265 are eliminated for various reasons, leaving 232,917 grid cells subject to further analysis.

2.4. Wind turbines considered, capital cost, and selection criteria

Here, 10 onshore and 2 offshore wind turbines are considered, which are listed in Table S1 of the Online Supplement along with key technical characteristics. These turbines were chosen for consideration because of the ready availability of power curve data. The power curves for each of these turbines are shown in Fig. S2.

On the basis of cost studies that are summarized in the Online Supplement, the following representative capital costs were adopted: \$2000/kW and \$3000/kW for onshore and offshore wind farms, respectively; \$0.50/kW/km and \$0.75/kW/km for onshore and offshore transmission lines, respectively; and transformer station costs of \$250/kW. As well, annual fixed operation and maintenance (O&M) costs equal 0.7%, 2.1%, and 0.7% of the capital cost for onshore wind turbines, offshore wind turbines, and transmission lines, respectively, were adopted along with a variable wind turbine O&M cost of \$0.007/kWh.

Three different criteria could be used for selecting the turbine to use in a given grid cell: (1) to maximize the annual electricity production per unit of land area; (2) to maximize the annual capacity factor (the ratio of average to rated power output); and (3) to minimize the generation cost of electricity. Annual electricity generation per unit land area depends on the turbine capacity, capacity factor and density (turbines/km^2). The capacity factor of a given turbine depends on the 80 m winds, the hub height and wind shear factor, and the wind speed probability distribution. For a given generator capacity, the capacity factor tends to be largest for turbines with larger rotors, which decreases the turbine density, so electricity production per unit land area may or may not be maximized. Maximizing electricity production per unit of land area would, for a given electricity production by a wind farm, reduce the length and cost of required within-wind farm cables and access roads, but the variation in these costs with turbine model is not considered here. Maximizing capacity factor would reduce the need for backup capacity and increase the reliability of electricity production, thereby tending to reduce costs, but these savings are also not considered here.

In order to provide a consistent basis for determining which turbine will yield the lowest cost electricity in a given grid cell, differences in the costs of different turbines need to be estimated. The $2000/kW onshore turbine cost is assumed to apply to the V80-1.8g turbine with a 105 m hub height, and the scaling relationships given in [31] are used to estimate how this cost should change as the turbine capacity, rotor diameter and hub height are varied. Results are given in the Online Supplement. The V100-1.8g turbine has a larger rotor than the V80-1.8g, for example, and has a larger capacity factor, but is estimated to cost more per kW of capacity because of the larger and hence more costly rotor and associated equipment.

Here, the turbine that provides the lowest cost electricity in each grid cell is selected, then the seasonal and annual electricity generation in each grid cell using the selected turbine is computed, and the grid cells are ranked in terms of decreasing annual electricity generation starting with the cell with the greatest electricity generation.

3. Results

We initially assess the number of wind turbines, and the areal extent of the associated wind farms, that would be needed to generate an average annual amount of electricity equal to the current total electricity generation in Canada by existing fossil fuel and nuclear powerplants, without consideration of the need for storage (and associated losses) to deal with supply–demand mismatches. We focus first on the distribution of grid cells with the greatest wind resource, followed by an estimate of the cost of supplying electricity to each of nine major electricity demand centres through high voltage direct current (HVDC) transmission lines. We also investigate the impact on the cost and seasonal mean capacity factor of deliberate oversizing of wind farms and of requiring some minimal geographical dispersion of the wind farms serving any given demand centre (dispersion increases reliability but reduces the average capacity factor because the wind turbines are then not concentrated in the regions of best wind). We conclude with a consideration of the potential for hydro-electric reservoirs to address seasonal supply–demand mismatches.

To set the context, Fig. 1 compares the hydro-electric, fossil fuel and nuclear electricity generation in each province (or provincial group) in Canada in 2007, while Table S2 lists the capacities, electricity generation, and capacity factors. Total existing (as of 2007) fossil fuel plus nuclear capacity (49.0 GW) and generation (249.8 TWh/yr) are each about 40% of the total national capacity

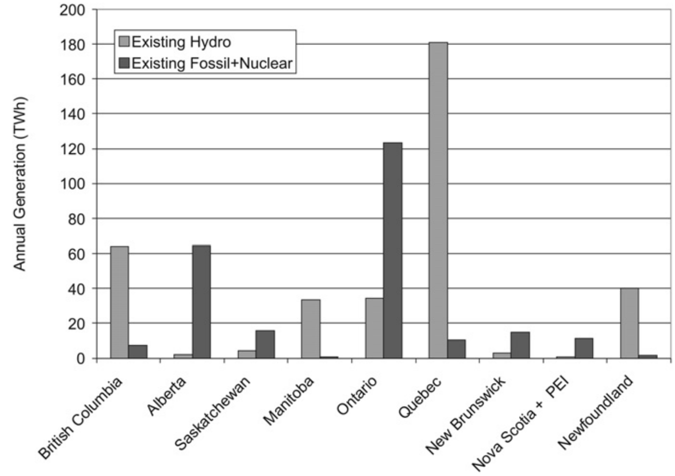

Fig. 1. Hydro-electric and fossil fuel + nuclear electricity generation in Canada in 2007. Source: Statistics Canada [21].

and generation (123.9 GW and 616.3 TWh/yr, respectively). Existing hydro-electric generation (363.5 TWh/yr) is about 1.5 times the wind electricity generation that would be required to replace all existing fossil fuel and nuclear electricity generation. The average capacity factors for existing wind, hydro, fossil fuel and nuclear powerplants are 0.210, 0.503, 0.566 and 0.754, respectively. The bulk of the fossil fuel and nuclear production is in Alberta and Ontario. The flexible storage capacity of hydro-electric reservoirs in Quebec and Manitoba is equal to several years of electricity production (Andrew Pietrowicz, Ontario Power Authority, personal communication, Sept. 2011). This combined with the low average capacity factor of hydro-electric powerplants indicates that there should be little difficulty in accommodating mismatches between wind electricity supply and the demand largely through compensating changes in hydro-electric power production. There are, as well, many other options for accommodating supply–demand mismatches (see the extensive discussion in Harvey [19], Section 3.11). Thus, there is some justification in examining – as a first step – the deployment and cost of a national wind powerplant sufficient to displace all existing fossil fuel and nuclear electricity production.

3.1. *Annual wind capacity factor and ranking of grid cells in terms of annual electricity generation*

Fig. 2 shows the annual wind turbine capacity factor in each grid cell of the domain under consideration; the top panel shows capacity factors using the turbine in each grid cell that minimizes the cost per kWh of electricity, while the lower panel shows the capacity factors using the turbine in each grid cell that maximizes the capacity factor.[1] Annual capacity factors are 0.4–0.7 offshore on the east coast and 0.3–0.4 or 0.3–0.5 (depending on the turbine selection criterion) offshore on the west coast, on Lake Manitoba and on all of the Great Lakes. Capacity factors in James Bay are largely 0.3–0.4 or 0.4–0.5. There are sizeable onshore areas in Quebec and Labrador with capacity factors of 0.4–0.5 using

[1] The turbines selected in the first case tend to be those with a smaller rotor for a given generator size, and result in both a lower cost per kWh of electricity and a lower capacity factor, while the turbines selected in the second case are those with a larger rotor for a given generator size. As shown in Fig. S2, there can be a factor of two difference in relative power output at wind speeds intermediate between the cut-in and rated wind speeds among different turbines, resulting in large differences in the capacity factor.

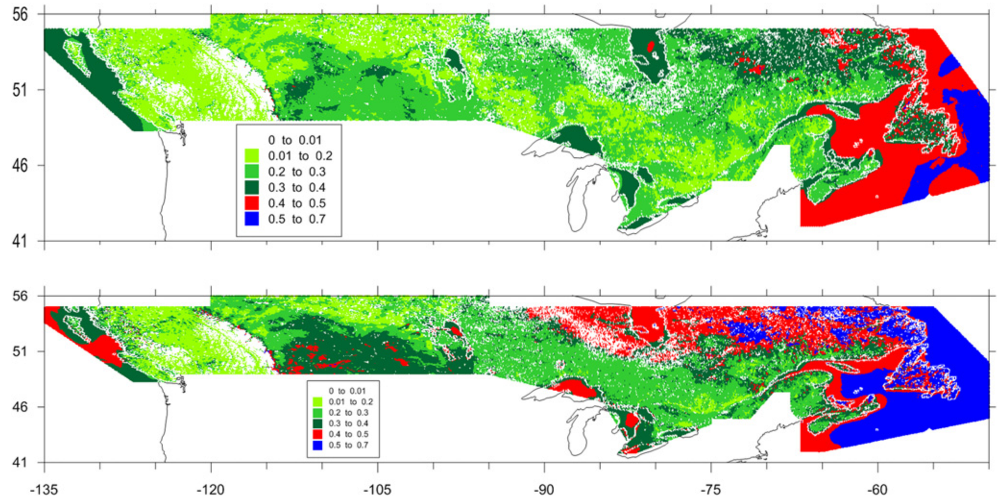

Fig. 2. Capacity factor for each grid cell in the analysis using the wind turbine in each grid cell that minimizes the cost of generating electricity (top) and using the wind turbine in each grid cell that maximizes the capacity factor (bottom).

turbines chosen under the cost minimization criterion, and 0.5–0.7 using turbines chosen to maximize the capacity factor. Most of the rest of the country has capacity factors less than 0.3, and large areas have a capacity factor less than 0.2 using either criterion for choosing turbines.

For the next step in the analysis, the domain of interest is divided into 5 sectors from west to east, and within each domain, cells are selected starting with the cell with the greatest annual wind energy potential and adding cells until the total annual wind energy generation in *each* of the sectors equals the total national fossil fuel and nuclear electricity generation. The cells selected this way are shown in Fig. 3, from which it can be seen that the selected cells tend to be contiguous and that a very small wind farm area in each sector would be sufficient to displace the entire current national fossil fuel- and nuclear-generated electricity. There is thus considerable scope for geographical dispersal of the wind farm powerplants. Although there is an enormous wind energy resource in Canada, the best resources tend to be offshore and/or relatively far (500–2000 km) from the major demand centres.

3.2. Cost of wind-generated electricity

In the next step of the analysis, nine major electricity demand centres are selected, one in each of the provinces or provincial groups shown in Fig. 1. To get a rough estimate of the cost of transmitting electricity from what are generally distant wind farms, all of the wind-generated electricity that is required in each province is assumed to be transmitted by HVDC to a node next to the major demand centre, from which electricity would be further distributed through the existing or strengthened high and medium voltage AC grid. Here, only the HVDC portion of the transmission and distribution system is considered. The cost of supplying electricity to each of the demand centres from each of the 232,917 cells in the domain of interest was calculated in the manner described below, then cells were assigned to each demand centre in order of increasing cost until the total annual electricity supply assigned to a given demand centre equals the total annual fossil fuel + nuclear electricity generation in the corresponding province. A given cell is never assigned to more than one demand centre.

The cost of electricity consists of contributions from the cost of the wind farm $C_{e-\mathrm{WT}}$, from the investment cost of transmission $C_{e-\mathrm{TL}}$, and due to losses of electricity during transmission. The first two cost components (in \$/kWh) are computed as

$$C_{e-\mathrm{WT}} = \frac{\left(\mathrm{CRF_{WT}} + \mathrm{OM}_{\mathrm{WT}-f}\right)\mathrm{CC_{WT}}}{\eta_a f_a 8760\mathrm{CF_{WT}}} + \mathrm{OM}_{\mathrm{WT}-\nu} \tag{12}$$

and

$$C_{e-\mathrm{TL}} = \frac{(\mathrm{CRF_{TL}} + \mathrm{OM_{TL}})\mathrm{CC_{TL}}}{8760\mathrm{CF_{TL}}}, \tag{13}$$

where $\mathrm{CC_{WT}}$ and $\mathrm{CC_{TL}}$ are the wind turbine and transmission line capital costs (\$/kW), respectively, $\mathrm{CRF_{TL}}$ and $\mathrm{CRF_{TL}}$ are the wind turbine and transmission line cost recovery factors (given later), $\mathrm{OM}_{\mathrm{WT}-f}$ and $\mathrm{OM_{TL}}$ are the wind turbine and transmission line fixed

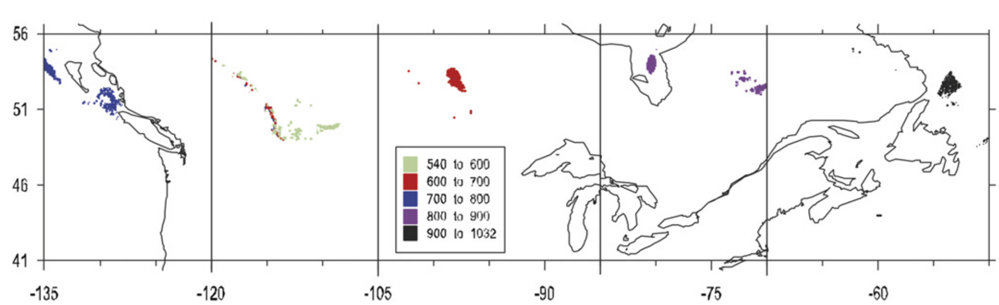

Fig. 3. Cells selected within each of five sectors, starting with the cell with the greatest annual wind energy potential and adding cells until the total annual wind energy generation in each of the sectors equals the total national fossil fuel + nuclear electricity generation in Canada in 2007 of 250 TWh. The legend gives GWh/yr/cell.

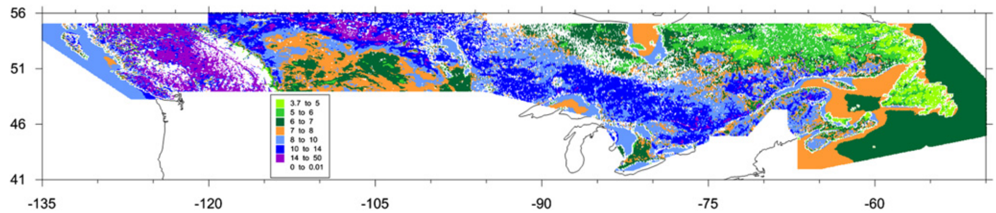

Fig. 4. The generation component of the cost (cents/kWh) of wind electricity using the wind turbine in each grid cell that minimizes the cost of generating electricity.

annual operation and maintenance (O&M) cost (as a fraction of the initial capital cost), OM_{WT-v} is the variable wind turbine O&M cost ($/kWh), f_a is the fraction of the time that the turbine is operational/available, η_a is an additional factor to take into account various energy losses that reduce the power output below that expected based on the turbine power curve and which are not already accounted for by reducing the effective wind speed (U_{a-i}, given by Eq. (11)), CF_{WT} is the wind turbine capacity factor expected based on the power curve, CF_{TL} is the transmission line capacity factor (equal to the average power transmission divided by the transmission capacity), and 8760 is the number of hours per year.

The availability factor f_a is typically 0.95–0.98 and allows for downtime for maintenance and repairs as well as unplanned shutdowns; a value of 0.97 is adopted here. The remaining energy losses, represented by η_a, are grid losses within the collection grid inside a wind farm, given as 1–3% by [32]. Possible additional losses of a few percent to heat the blades in winter so as to prevent icing are neglected.

The effect of transmission loss is to increase the amount of electricity that must be generated in order to supply a given demand. This component of the transmission cost is given by the required extra electricity times the cost of electricity (as given by the sum of C_{e-WT} and C_{e-TL}). The total cost of electricity, including energy losses, is thus given by

$$C = \frac{C_{e-WT} + C_{e-TL}}{1 - T_{loss}CF_{TL}} = (C_{e-WT} + C_{e-TL})\left(1 + \varepsilon + \varepsilon^2 + ...\right) \\ = (1 + \delta)(C_{e-WT} + C_{e-TL}) \tag{14}$$

where T_{loss} is the fractional loss at full transmission line capacity, $\varepsilon = T_{loss}CF_{TL}$ and $\delta = \varepsilon/(1-\varepsilon)$.[2] Transmission losses vary in proportion to the transmitted power, and so will vary in proportion to the average transmission line capacity factor.

The cost recovery factor, or CRF, is the fraction of the original investment cost that must be paid back every year in order to exactly pay back the original investment over a period of n years with interest at an annual rate i. It is given by

$$CRF = \frac{i}{1 - (1 + i)^{-n}} \tag{15}$$

Here, it is assumed that $n = 20$ years for wind turbines, $n = 40$ years for transmission lines, and $i = 0.03$ in both cases. The interest rate assumed here is substantially lower than the rate of return demanded by (and still received by) private investors. However, Canadian governments and power utilities are financially sound and can borrow at real interest rates that are substantially lower than the rate of return demanded by private investors. Financing at 3%/yr substantially reduces the cost of wind-generated electricity and, as seen below, results in manageable wind electricity costs in spite of the large turbine and transmission costs assumed here.

Fig. 4 shows the geographical variation in the generation component (Eq. (12)) of the cost of wind electricity, while Fig. 5 shows the marginal cost of electricity generation as grid cells are added so as to increase the annual production from 0 to 10 times the 2007 fossil fuel + nuclear electricity generation. The turbine capacity factor shown in Fig. 2 is a key factor in the cost of electricity. Offshore cells typically have a much higher capacity factor than onshore cells, but this does not compensate for the greater capital cost of offshore wind farms, so the cost of offshore electricity is generally greater than the cost of onshore electricity for the specific set of assumptions adopted here. The cost of the next increment of electricity generation is just under 5 cents/kWh by the time generation reaches 10 times the fossil fuel + nuclear supply, while requiring wind farms covering only 3.3% of the land area of the domain considered here. This underlines the enormity of Canada's wind energy resource.

The cells selected so as to minimize the total cost of providing electricity to the demand centres are almost entirely in Alberta, Labrador and Newfoundland, as the high capacity factors in these regions more than compensate for costs in transmission to other regions. To avoid over-reliance on winds in any given region, the following dispersion requirements were imposed:

- at least 50% of the wind electricity supplied to British Columbia comes from within the province or its coastal waters;
- at least 50% of the electricity supplied to Alberta comes from Saskatchewan or further east;

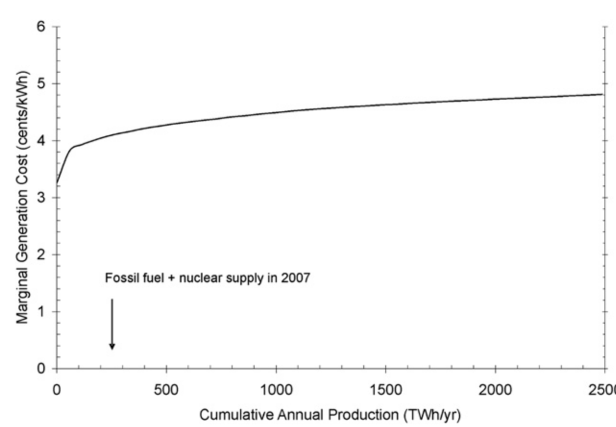

Fig. 5. The marginal cost of electricity generation as the annual electricity generation increases from 0 to 10 times the 2007 fossil fuel + nuclear electricity generation, using the wind turbine in each grid cell that minimizes the cost of generating electricity.

[2] The term $(1 + \varepsilon + \varepsilon^2 + \ldots)$ arises from a Taylor series expansion of $1/(1-T_{loss}CF_{TL})$, while the expression for δ is the expression for the sum of an infinite series involving ε. Some papers give the cost of lost electricity as $(C_e + C_t)\varepsilon$, that is, neglecting the higher order terms in ε. The first-order term (ε) accounts for the extra generation required to account for the loss of electricity, but some of this extra generation is itself lost, which is accounted for by the second-order term (ε^2), and so on.

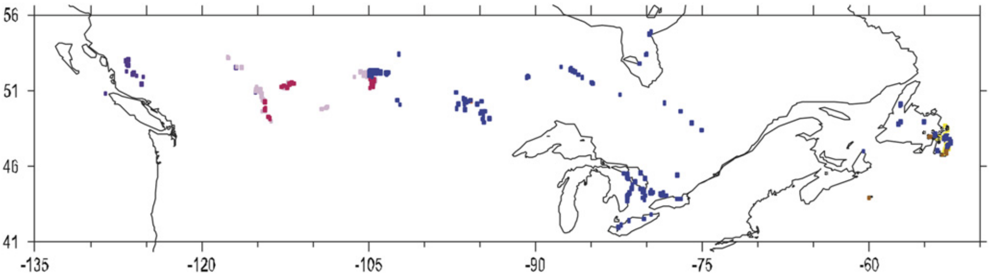

Fig. 6. Cells that are selected to provide the electricity for each demand centre, beginning with electricity from the least-cost cell and adding cells until an amount of electricity equal to the current annual supply from fossil fuels and nuclear is provided, with requirements for geographical dispersal of the selected cells.

- at least 50% of the electricity supplied to Saskatchewan comes from west and 50% from east of 106°E; and
- 30% of the electricity supplied to Ontario comes from west of 90°E, 30% comes from east of 70°E, and the balance comes from 70 to 90°E but split equally between regions north and south of 50°N.

No restrictions are placed on the supply of wind electricity to the other demand centres. Fig. 6 shows the resulting distribution of selected cells. Requiring dispersal of wind turbines will presumably reduce the variability of electricity production at time scales shorter than the time scale of travelling extra-tropical low pressure systems (i.e., at time scales of one week and less), but increases the average cost of electricity. Fig. 7 gives the average capacity factor for the wind grid cells that supply the various demand centres, as well as the average cost of electricity supplied. Results are shown for the unconstrained and geographically-constrained selection for the first five demand centres. Average capacity factors for the unconstrained case are 0.40–0.53 and average costs are 4.5–6.4 cents/kWh (Table 1). Constraining the selection generally results in smaller capacity factors and greater costs.

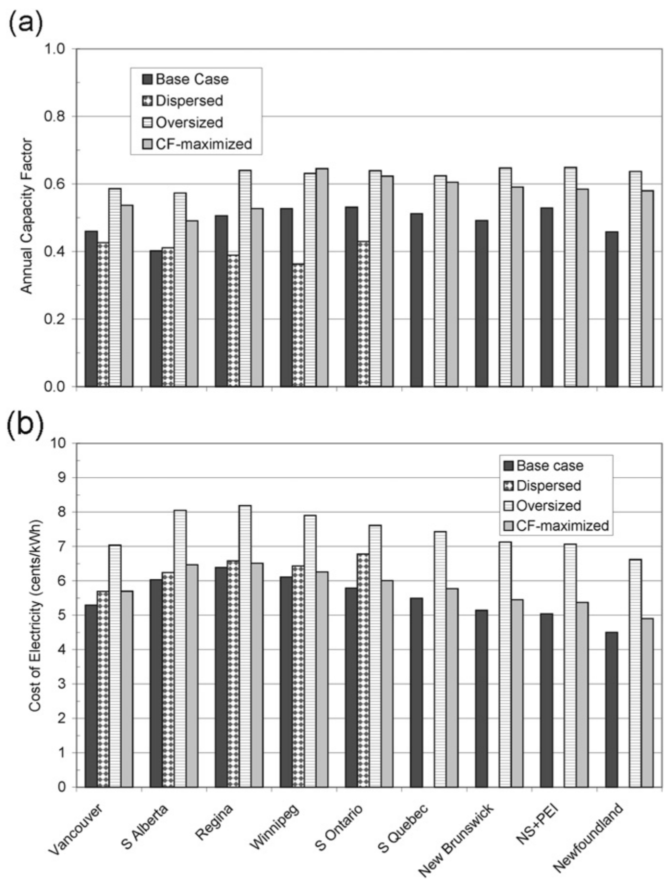

Fig. 7. (a) The average capacity factor for the wind grid cells that supply the various demand centres, and (b) the average cost of electricity from these cells. Results are shown for the base case, with required geographical dispersal of cells, with undersizing the transmission link from each grid cell by a factor of two – all using the wind turbine in each grid cell that minimizes the cost of generating electricity – and when the wind turbine that maximizes the annual capacity in each grid cell factor is chosen.

3.3. *Oversizing individual wind farms/undersizing of transmission lines*

The impact of arbitrarily restricting the transmission capacity from all grid cells to half the turbine capacity in each grid cell is explored here. With this restriction, the capacity factor of the wind farm decreases because some potential output, at high winds, is spilled, but the capacity factor of the transmission line is twice the reduced wind farm capacity factor and is larger than the capacity factor for the non-oversized base case wind farm/transmission line sizing. The transmission line capacity factor is the capacity factor that the customers in the demand centres see, and so it will be referred to here as the demand-side capacity factor. The demand-side capacity factor is shown in Fig. 7, and ranges from 0.57 to 0.65. Average electricity costs are also shown in Fig. 7, and range from 6.6 to 8.2 cents/kWh. With undersizing of the transmission lines, more grid cells are needed (each with additional undersized transmission links) in order to generate and deliver the same amount of electricity, so the total wind farm capacity that must be constructed is larger but the overall peak transmission capacity is reduced. Table 2 gives further information comparing the base case and oversized wind farms.

Undersizing of the transmission links results in the largest wasted generation potential in winter (when winds are strongest) and the smallest wastage in summer. The result is to reduce the relative difference in the delivery of electricity between summer and winter. This is shown in Fig. 8, which gives the seasonal capacity factors for five demand centres with and without oversizing of the wind farms relative to the transmission links. For non-oversized wind farms, the summer capacity factor is 0.65–0.78 of the winter capacity factor, while for oversized wind farms, the summer capacity factor is 0.78–0.81 of the winter capacity factor.

Two considerations that would alter the cost of oversizing wind farms are (i) transmission costs do not increase in direct proportion to transmission capacity, due to economies of scale, so the savings in transmission line costs would be less than calculated here; and (ii) wind electricity produced at times of maximum wind would likely be sold at less than the average cost of electricity, so the loss of revenue due to spilled electricity would be less than calculated here. These two factors would offset each other to some extent.

Table 1
Characteristics of the grid cells serving the nine different demand centres for the case with no dispersal requirement. TR_{loss} is the cost of electricity lost during transmission, while all other terms are as defined in the text.

Demand centre	No of cells	CC_{WT} ($/kW)	Trans. distance (km)	CC_{TL} ($/kW)	$T_{loss}CF_{TL}$	$\overline{U}$	CF_{WT}	Cost of electricity (cents/kWh)			
								C_{e-WT}	C_{e-TL}	TR_{loss}	Total
Vancouver	15	1862	677	839	0.029	11.53	0.460	4.11	1.11	0.07	5.29
S_Alberta	154	2059	365	683	0.021	9.68	0.402	4.97	1.02	0.05	6.03
Regina	29	2165	2043	1521	0.063	10.31	0.506	4.3	1.86	0.23	6.39
Winnipeg	1	1593	3401	2200	0.097	11.7	0.527	3.26	2.54	0.31	6.11
S. Ontario	219	2083	1820	1410	0.058	10.67	0.531	4	1.61	0.18	5.79
S. Quebec	19	1952	1465	1232	0.049	10.72	0.512	3.9	1.46	0.14	5.49
NBrunswick	28	1872	832	933	0.033	10.61	0.492	3.9	1.15	0.08	5.14
Nova Scotia + PEI	22	2014	831	916	0.033	10.34	0.529	3.9	1.05	0.09	5.04
Newfoundland	3	1648	87	544	0.014	10.65	0.458	3.75	0.72	0.03	4.50

3.4. Oversizing the overall system

If more than one high-wind region is called upon to serve a given demand centre at different times, and if a given high-wind region needs to serve different demand centres at different times, then the system as a whole will be oversized and it will be necessary to have transmission capacity equal to a substantial fraction of the wind farm capacity to more than one demand centre. For example, in winter, Alberta would at times need to be supplied by offshore British Columbia or by wind farms in Manitoba, depending on where within these regions a given extra-tropical cyclone and associated strong winds are located (with fallback on hydro-power from British Columbia and Manitoba if neither region has adequate wind), while southern Ontario would at times need to be supplied by Manitoba, the James Bay region, or Labrador (with fallback on hydropower from Manitoba or Quebec). This would be to assure that there would usually be a region with strong winds somewhere at any given time that is capable of serving each demand centre, with hydro or another form of storage as backup. If, as a result, wind farms capable of supplying 150 TWh to meet a demand of 100 TWh are built in widely scattered locations, so as to increase the likelihood of various levels of power output at any given time, then 1/3 of the generation potential will be wasted, so electricity that would have cost 5–6 cents/kWh will cost (5–6 cents/kWh)/(1-1/3) = 7.5–9.0 cents/kWh.

3.5. Selecting turbines that maximize annual capacity factor

The preceding analysis is based on selecting the turbine, in each grid cell, that minimizes the generation cost of electricity, then ranking all of the grid cells in terms of annual electricity generation or in terms of total (generation plus transmission) cost in supplying each of the demand centres. An alternative is to initially select the turbine for each grid cell that maximizes the annual capacity factor. The impact on the average capacity factor of the turbines supplying each demand centre and of the average cost of electricity to each demand centre is shown in Fig. 7 (as the bars labelled CF-maximized); average costs range from 4.9 to 6.5 cents/kWh and average capacity factors range from 0.49 to 0.65. Turbines with large capacity factor have a larger rotor and hub height in relation to the generator capacity, and so a larger cost per kW of capacity. Choosing the turbine that maximizes annual capacity factor rather than minimizing cost increases electricity production more in the summer than in the winter, thereby increasing the ratio of JJA to DJF electricity production (from 0.65–0.78 to 0.69–0.87). As seen from Fig. 7, choosing the turbine that maximizes capacity factor at each grid cell rather than minimizing cost sometimes results in average capacity factors comparable to the oversized case but with minimal additional cost (compared to the difference between the oversized and base cases). Thus, selecting the turbine that maximizes annual capacity factor seems to be a better strategy than selecting the turbine that minimizes generation cost and oversizing the wind farm to increase reliability.

3.6. Impact of alternative interest rates

One of the key findings of this study is that an amount of electricity sufficient to displace all existing fossil fuel and nuclear electricity generation in Canada can be produced from wind at average costs (including transmission costs) of 4.5–6.4 cents/kWh, using up-to-date estimates of the installed costs of wind turbines and transmission lines in Canada and accounting for reasonable economies of scale and price discounts for large purchases of wind turbines. The low estimated cost depends on the assumption of a low interest rate (3%/yr) in financing the construction of the wind farms and transmission links – something that is feasible with

Table 2
Comparison of the wind farm powerplant serving each demand centre for the base case and where the transmission links are only one half the capacities of the wind farms (Oversized case, referring to the wind farm size relative to the transmission link).

Demand center	Number of grid cells used		Areal extent (km^2)		Number of 2-MW turbines		Total capacity (GW)		Turbine capacity factor		Wasted fraction
	Base	Over-sized	Base	Over-sized	Base	Over-sized	Base	Over-sized	Base	Over-sized	
British Columbia	15	22	316	471	980	1475	2.0	3.0	0.460	0.293	0.344
Alberta	154	204	3229	4378	9193	12,908	18.4	25.8	0.402	0.286	0.329
Saskatchewan	29	41	643	898	1767	2790	3.5	5.6	0.506	0.320	0.344
Manitoba	1	2	22	39	69	124	0.1	0.2	0.527	0.315	0.339
S. Ontario	219	350	4828	7574	13,267	22,088	26.5	44.2	0.531	0.319	0.357
S. Quebec	19	31	411	654	1180	1883	2.4	3.8	0.512	0.312	0.355
New Brunswick	28	47	601	1017	1771	2632	3.5	5.3	0.492	0.324	0.374
Nova Scotia + PEI	22	37	478	802	1263	2036	2.5	4.1	0.529	0.325	0.378
Newfoundland	3	6	63	128	200	323	0.4	0.6	0.458	0.319	0.375
National	490	740	10,591	15,962	29,688	46,260	59.4	92.5	0.484	0.310	0.351

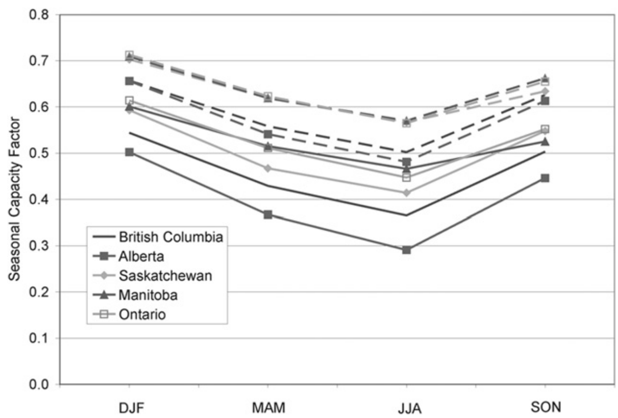

Fig. 8. Seasonal variation in electricity supplied to five demand centres for the base case (solid lines) and for wind forms oversized by a factor of two (dashed lines) relative to the capacity of the transmission link.

government-backed utility financing. Fig. 9 compares the impact on electricity costs for financing at rates ranging from 3%/yr to 12%/yr, the later being comparable to the rates of return currently demanded by private investors. For financing at 12%/yr, the cost of electricity delivered to the nine demand centres is about twice the cost as for financing at 3%/yr, ranging from 8.1 cents/kWh to 12.3 cents/kWh.

4. Discussion, conclusions, and next steps

There is a widespread perception that renewable energy, including wind energy, is not up to the task of replacing fossil fuels and nuclear energy supply. Many analysts argue or assume that continued reliance on, and expansion in the supply of, nuclear energy along with carbon capture and storage (CCS) on some fossil fuel powerplants will be an essential part of energy systems that eventually eliminate electricity-related fossil fuel emissions (so, for example, the energy pathways in the recent *Global Energy Assessment* [33] include scenarios with and without reliance on nuclear energy and no less than 9% of global primary energy in 2050 from fossil fuels with CCS, while the aggressive 2DS scenario in the latest *Energy Technology Perspectives* of the International Energy Agency [34] assumes that fossil fuel plants equipped with CCS and nuclear power provide 14% and 19% of global electricity demand, respectively, in 2050).

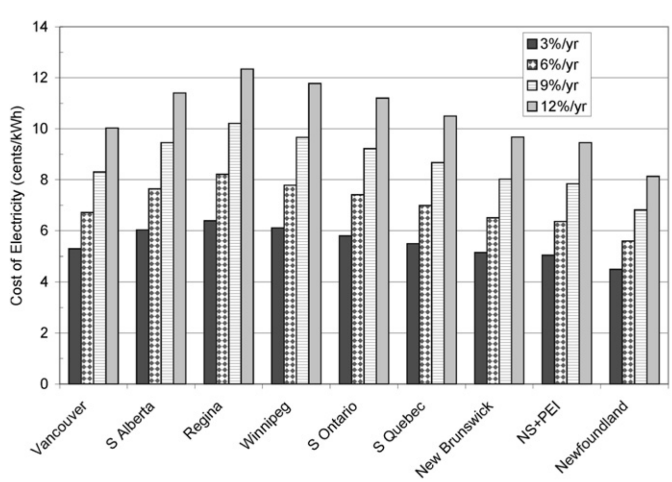

Fig. 9. Cost of electricity with rates of return on the capital investment of 3%/yr to 12%/yr for the base case (no oversizing of wind farms relative to the transmission links and no forced geographical dispersal), using the wind turbine in each grid cell that minimizes the cost of generating electricity.

The analysis presented here demonstrates that the wind electricity potential in Canada is many times the current total electricity demand. Good wind sites are widely distributed across the country but are generally far from the major demand centres. However, capacity factors in these regions are so large (0.5–0.65) using the turbine in each grid cell that maximizes annual mean capacity factor that, even after accounting for transmission costs and losses (using HVDC lines), the cost of wind-generated electricity would be in the 5–7 cents/kWh range. This is less than the expected eventual cost of electricity from new coal powerplants with carbon capture and storage (6 eurocents/kWh or 9 cents Cdn/kWh for the highly optimistic assumption of powerplant capital cost of €2000/kW according to [35]), but without the substantial negative environmental impacts of coal mining. It is substantially less than recent estimates (summarized by Cooper [36]) of the cost of electricity from a new generation of nuclear powerplants (10–23 cents/kWh) by an even larger margin, but without the million-year legacy of radioactive waste and other problems (reviewed in [19], Chapter 9). Conversely, the International Energy Agency [37] sees the potential for significant improvements in the capacity factor of wind turbines in a given wind regime (by up to 35% of current capacity factors) through various technical advances, which would reduce unit electricity costs significantly. Costs could be further reduced with minimal impact on output if variable speed turbines in a remote wind farm (whether onshore or offshore) are connected to a variable frequency AC grid that in turn is connected to the HVDC link with a single large converter, rather than using a power converter at each wind turbine to connect to a fixed frequency AC grid that in turn is connected to the HVDC link with a large power converter, as proposed by [38] for offshore wind farms.

Thus, although the costs of all potential future energy supplies and of transmission lines are uncertain, it is concluded that wind energy (in combination with existing and planning future hydroelectric power and other storage and demand management options) represents a competitive and viable alternative in Canada to fossil fuel powerplants with carbon capture and storage and to nuclear power.

4.1. Future research steps

The next step in the analysis will be to use time series of 3-hourly wind speeds on a 25 km × 25 km grid, as provided by the North American Regional Reanalysis dataset [39], in combination with hourly electricity demand data at sub-provincial scales, to determine the extent to which wind variations at widely separated locations are uncorrelated with one another at time scales ranging from 3-hourly to seasonal, and the extent to which storage options or load shifting would be needed to match optimally-distributed wind farms and electricity demand. Account will be taken of projected growth in electricity demand, both with and without strong energy efficiency measures and potential use of ground-source heat pumps in district energy systems as a dispatchable electricity load [40].

Acknowledgements

Yazan Kawar downloaded and assembled the data from the Canadian Wind Energy Atlas, Marcel Fortin of the University of Toronto Map Library extracted the land use data and converted it to a text file that could be read by the Fortran program used for this analysis, and Taylor Binnington prepared the land surface elevation and slope data used here and provided useful comments.

Appendix A. Supplementary data

Supplementary data related to this article can be found at http://dx.doi.org/10.1016/j.energy.2012.12.008.

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Online Supplementary Material

Tables S1 and S2 provide details concerning the wind turbines considered here and concerning the existing electricity supply system in Canada, respectively. Figure S1 compares two representative Weibull wind speed probability distribution functions, the first yielding a mean wind speed of 7.1 m/s and the second 10.3 m/s, with a typical wind turbine power curve, while Figure S2 gives the power curves for all the turbines considered here. As can be seen from Fig. S1, for relatively low mean wind speeds, the wind speed distribution is such that the turbine output will be below the rated output most of the time, whereas for large wind speeds output will frequently be at the rated output. As seen from Fig. S2, turbines with a larger rotor relative to their rated capacity have greater output at low wind speeds than turbines with a smaller rotor, but may have a smaller cut-out wind speed (and will have greater unit cost), so the turbine that maximizes annual electricity production or minimizes unit electricity cost depends on the wind speed probability distribution.

Table S1. Characteristics of the turbines considered here. The last two entries are offshore turbines. Source: Product brochures from www.vestas.com, accessed 5 February 2012.

Model	Rated Power (MW)	Rotor dia (m)	Hub height (m)	Generator Type	Rotor rpm	Wind Speeds (m/s)		
						Cut-in	Rated	Cut-out
V90-1.8g	1.8	90	80-105	PMG	Variable[1]	4.0	12.5	25
V90-1.8	1.842	90	80-95	6-pole DFIG	9.3-16.6	4.0	12.5	25
V100-1.8g	1.8	100	80-125	PMG	Variable	3.0	12.0	20
V100-1.8	1.833	100	80-95	6-pole DFIG	9.3-16.6	3.0	12.0	20
V80-2.0g	2.0	80	65-80	PMG	Variable	4.0	14.1	25
V80-2.0	2.0	80	60-100	4-pole DFIG	10.8-19.1	4.0	14.5	25
V90-2.0g	2.0	90	80-125	PMG	Variable	4.0	12.2	25
V100-2.6	2.6	100	100[2]	4-pole DFIG	6.7-13.4	3.0	15.0	23
V90-3.0	3.0	90	65-80	4-pole DFIG	8.6-18.4	3.5	15.2	25
V112-3.0on	3.0	112	119	PMG	6.2-17.7	3.0	11.5	25
V112-3.0off	3.0	112	100[2]	PMG	8.1-19.0	3.0	12.5	25
V164-7.0	7.0	164	140[2]	PMG	4.8-12.1	4.0	15.0	25

[1] Unspecified in the product brochure
[2] Hub heights are unspecified. Shown is the value adopted here.

Table S2. Electrical powerplant capacity, electricity generation, and capacity factors in Canada in 2007. Source: Statistics Canada [1]										
Region	Capacity (MW)					Generation (GWh)				
	Hydro	Wind+ Tidal	Nuclear	Fossil Fuel	Total	Hydro	Wind+ Tidal	Nuclear	Fossil Fuel	Total
British Columbia	12609	0	0	2223	14832	64288	0	0	7545	71833
Alberta	909	439	0	10503	11851	2141	716	0	64575	67432
Saskatchewan	855	171	0	2853	3879	4393	579	0	15602	20574
Manitoba	5029	104	0	494	5627	33513	325	0	565	34403
Ontario	8350	414	11990	11413	32166	34336	493	79750	43655	158234
Quebec	37459	376	675	2508	41018	181100	617	4322	5923	191962
New Brunswick	923	0	680	2931	4534	2803	0	4119	10717	17639
Nova Scotia+PEI	404	96	0	3164	3664	925	217	0	11477	12619
Newfoundland	6796	0	0	557	7353	40049	0	0	1534	41583
Total or Average	73334	1600	13345	36645	124924	363548	2947	88191	161593	616279

Table S2 (continued).					
Region	Capacity Factor				
	Hydro	Wind+ Tidal	Nuclear	Fossil Fuel	Total
British Columbia	0.582	0.000	0.000	0.387	0.553
Alberta	0.269	0.186	0.000	0.702	0.650
Saskatchewan	0.587	0.386	0.000	0.624	0.605
Manitoba	0.761	0.357	0.000	0.131	0.698
Ontario	0.469	0.136	0.759	0.437	0.562
Quebec	0.552	0.187	0.731	0.270	0.534
New Brunswick	0.347	0.000	0.691	0.417	0.444
Nova Scotia+PEI	0.261	0.257	0.000	0.414	0.393
Newfoundland	0.673	0.000	0.000	0.314	0.646
Total or Average	0.566	0.210	0.754	0.503	0.563

Capital Cost of Wind Farms and Transmission Links

The cost of wind turbines (as well as that of fossil fuel power plants and the estimated cost of new nuclear power plants) has increased dramatically during the past five years. Total installed costs of onshore turbines in Europe in 2006 ranged from €1000-1350/kW (Cdn$1300-1800/kW), but recent total installed costs in Ontario have been in the range $2110-3430/kW, with an average of $2630/kW [2].

In the case of offshore wind farms, costs in Europe went from $1500-2000/kW before 2005 to $3200-5800/kW after 2005 (in terms of 2010US$, where 1US$ ~ 1Cdn$), with the main factors being growth in demand outstripping supply, limited availability of ports and vessels, increases in labour costs and commodity prices, corporate changes at the two major offshore turbine suppliers, and movement to projects in deeper water and further from shore [3]. Weißensteiner et al. (2011, Table A2) [4] give cost breakdowns for some offshore wind projects. Hardware costs (turbine purchase, delivery and erection, foundations, and internal grid) ranged from about US$1650-3750/kW, with design and management costs of $300-500/kW and main cable and substation costs of $500-1000/kW, giving a total cost of $2450-5250/kW. Heptonstall et al. (2012) [5] adopt a 2009 baseline cost for offshore wind farms in the UK of £1500/kW for turbines, £700/kW for foundations, £600/kW for electrical infrastructure, and £400/kW for planning and development costs. This gives a total cost of £3200/kW (~US$5000/kW). Costs by the mid 2020s are expected to be in the range £2200-3300 ($3400-5200/kW).

The US Energy Information Administration, in its *Annual Energy Outlook 2010*, gives a best estimate of overnight costs for onshore and offshore wind in 2009 (including project contingency factors) of $1966/kW and $3937/kW (in 2008US$), respectively [6, Table 8.2]. Costs of onshore turbines alone in the US (excluding foundations and installations but including delivery) rose from about $800/kW in 2001-2 to about $1300/kW in 2008-9, then dropped to about $1100/kW by July 2011 [7]. Northern onshore installations would cost more than southern installations, due to the need for low-temperature seals and other cold-weather packages, as well as often significantly greater foundation costs (Tim Weis, personal communication, January 2012). On the other hand, costs can be substantially reduced through economies and scale and the willingness of turbine manufacturers to offer deep discounts for large orders. For example, Junginger et al. (2005) [7] report that the purchase price of turbines has been reduced by up to 45% for orders of 500-1600 turbines. The production of wind turbine rotors requires the construction of blade moulds. Lindenberg et al. (2008) [8] suggest that segmented moulds could be transported to temporary manufacturing facilities that are established near the site of new large wind farms, thereby reducing transportation costs. For offshore wind farms, these temporary manufacturing facilities could be located on the coast, permitting delivery of all materials and components by ship in regions where there is no road access. Offshore wind energy is still relatively new and so should be amenable to greater relative cost reductions than onshore wind, although this may require a greater research and development effort, as van der Zwaan et al. (2012) [9] estimate that the progress ratio for offshore wind is 0.95 (compared to 0.80 for onshore wind, meaning that costs have fallen by only 5% for each doubling in cumulative global production).

In light of these considerations, and because we are considering a scenario with very large deployment of wind turbines, we adopt wind farm capital costs (excluding grid connection) of $2000/kW for onshore turbines and $3000/kW for offshore turbines, plus an additional cost of up to $400/kW (at a distance of 400 km or greater from the closest demand centre) for onshore turbines, in order to reflect the greater expense of shipping to and installing wind turbines in more remote locations. The $2000/kW onshore cost is assumed to apply to the VG80-1.8g turbine with a hub height of 90 m. This unit cost is altered based on departure of rotor diameter and hub height of other turbines from those in the reference turbine, as explained later.

The $3000/kW cost for offshore wind turbines is based on turbines mounted on the seabed. As noted in the main text, a few different floating offshore wind turbine concepts are currently being tested or developed. It may be that floating offshore wind turbines will be less expensive, once mature, than offshore turbines mounted on the seabed. Costs could be lower due to the absence of seabed construction, large ships, equipment out at sea, and the decommissioning of a large installed structure [10].

The cost adopted for offshore wind energy is particularly uncertain, as it is based on turbines mounted in the seabed, whereas many of the ocean grid cells pertain to sufficiently deep water that any offshore wind turbines in these cells would be floating (for which reliable cost data are not yet available).

With regard to onshore transmission lines, various estimates are given in Table S3.

Table S3. Recent estimates of the costs of onshore HVDC lines.

Voltage	Capacity (MW)	Cost (million$/km)	Cost ($/kW/km)	Source
345 kV	1250*	0.65-0.68	0.70	
500 kV	3000*	0.93-1.61	0.59	Hoppock and Patiño-Echeverri (2010)
800 kV	7500*	2.29-2.48	0.42	[11]
	1250	1.45	1.16	Pattanariyankool and Lave (2010)
	3000	2.41	0.80	[12],Curve fit equation,
	7500	4.08	0.54	Cost($/km)=$23959 $T^{0.5759}$, where
	10000	4.82	0.48	T=transmission capacity (MW)
500 kV	3000	0.99	0.33	
600 kV	3000	1.12	0.37	Bahrman and Johnson (2007) [13]
800 kV	3000	1.21	0.40	
500 kV	3000*	0.68-0.86	0.42	Mills et al (2009) [14]
800 kV	7500*	2.30	0.31	
800 kV	5700		0.31	EnerNex Corporation [15]

*Representative value assumed here.

The costs given here pertain to bipolar lines, which have the advantage that if one cable is broken, the other cable can temporarily transmit half the power by itself with grounded return (long term, operation in this mode would induce corrosion of buried pipes). The cost of a 500-kV HVDC line is 0.54-0.70 that of the cost of a double circuit 500-kV HVAC line [15].

With regard to offshore HVDC cables, costs estimated for a proposed HVDC line from Victoria, British Columbia to Port Angeles, Washington are $1.51/kW/km for transmission of 530 MW at 150 kV and $1.05/kW/km for transmission of 700 MW at 300 kV.[3]

With regard to AC-DC transformer station costs, Kim et al. (2009) [15] indicate costs of $170/kW and $145/kW for the termini of 1000-MW and 2000-MW 500-kV lines, respectively, and a cost of $150/kW for the termini of a 3000-MW, 600-kV line, but they stress that these costs are highly uncertain and do not include purchasers costs, which (they note) can be substantial. Mills et al. (2009) [16] indicate station costs of $100-200/kW. Bahrman and Johnson (2007) [13] indicate costs of $140/kW, $155/kW and $170/kW for the two stations at the ends of a 3000 MW line with voltages of 500 kV, 600 kV and 800 kV, respectively.

A 2003-2004 study of a proposed 500-kV, 1300-MW DC line that was to run from Manitoba to Sudbury, Ontario estimated line costs of $0.54/kW/km and station costs of $450/kW (based on information provided by Jatin Nathwani, personal communication, November 2011). The line costs are consistent with those shown in Table S3 for various voltage-power combinations, but the station costs are substantially greater.

The appropriate costs depend on the transmission voltage and capacity, with lower costs per kW of transmission capacity for higher capacity lines and greater costs for higher voltage at a given capacity. Here, we assume a capacity of at least 3000 MW for most of the lines that would need to be constructed to serve the 9 demand centres. This should result in lower line costs but greater

[3] See http://www.bcuc.com/Documents/Proceedings/2005/DOC_7599_C12-2%20SeaBreeze_IR-1.pdf.

station costs than given above for the proposed Manitoba-Ontario link. However, costs would have increased since 2003-2004. In light of the above, we adopt transmission costs of \$0.5/kW/km and \$0.75/kW/km for onshore and offshore lines, respectively. We adopt transformer costs of \$250/kW, which is less than estimated for the Manitoba-Ontario link but greater than the more recent US estimates. Our costs are substantially greater than the line and transformer costs expected in Europe (\$0.06-0.09/kW/km and \$150/kW, respectively, according to GAC (2006)) [17] or the average costs of 0.2€/kW/km and 50€/kW adopted by Weigt et al. (2010) [18] for a system of 3 lines in Germany at voltages of 110 kV, 220 kV and 380 kV.

Fixed O&M costs are assumed to be 0.7%/yr, 2.1%/yr, and 0.7%/yr of the capital cost for onshore wind turbines, offshore wind turbines, and transmission lines, respectively, while the variable wind turbine O&M cost is assumed to be \$0.007/kWh (based on various sources summarized in [19, Table 3.14].

Scaling relations to estimate the relative costs of different wind turbines

The distribution of costs for a 1.5-MW turbine with a 70m rotor and a 65m hub height, and scaling relationships given in [20], were used to estimate the costs of other onshore turbines relative to the cost of the Vestas V80-1.8g turbine, which is assumed to have total installed cost in Canada of \$2000/kW. The scaled cost C_s of a component with reference cost C_r is a given by

$$C_s = C_r \left(\frac{D_s}{D_r}\right)^d \left(\frac{R_s}{R_r}\right)^r \left(\frac{H_s}{H_r}\right)^h \left(\frac{S_s}{S_r}\right)^s \quad \text{(S.1)}$$

where D_r, R_r, H_r and S_r are the reference rotor diameter, generator rating, hub height and rotor swept area, respectively, and D_s, R_s, H_s and S_s are the scaled values (for the alternative turbines under consideration). Table S4 gives the distribution of costs in 2002 for the reference turbine used in [20], the costs for the V80-1.8g as scaled from the 2002 reference turbine, with all turbine components adjusted uniformly in cost so as to give a total cost of \$2000/kW, and the exponents d, r, h and s used in the scaling relationships. Table S5 gives the resulting turbine costs, which are adopted here. Turbines with a low rotor diameter and a low hub height for a given power rating have lower costs per kW of capacity.

Table S4. Component costs and scaling relationships used to estimate the relative costs of the different onshore turbines considered here. Source: Fingersh et al. (2006) [20].

Component	Component cost (1000$) 2002 1500-kW Reference turbine	V80-1.8g turbine scaled to $2000/kW	Scaling Exponent *d*	*r*	*h*	*s*
Rotor						
Blades	152	478	2.600	0.000	0.000	0.000
Hub	43	133	2.530	0.000	0.000	0.000
Pitch mechanism & bearings	38	121	2.660	0.000	0.000	0.000
Spinner, nose cone	4	8	1.000	0.000	0.000	0.000
Total	237	740				
Drive train, nacelle						
Low speed shaft	21	71	2.887	0.000	0.000	0.000
Bearings	12	37	2.500	0.000	0.000	0.000
Gear box	153	314	0.000	1.250	0.000	0.000
Mechanical brake	3	6	0.000	1.000	0.000	0.000
Generator	98	190	0.000	0.920	0.000	0.000
Variable speed electronics	119	234	0.000	1.000	0.000	0.000
Yaw drive and bearing	20	69	2.964	0.000	0.000	0.000
Main frame	93	231	1.670	0.000	0.000	0.000
Electrical connections	60	118	0.000	1.000	0.000	0.000
Hydraulics, cooling system	18	35	0.000	1.000	0.000	0.000
Nacelle cover	21	41	0.000	1.000	0.000	0.000
Total	618	1346				
Control, safety, monitoring						
Total	35	57	0.000	0.000	0.000	0.000
Tower						
Total	147	642	0.000	0.000	1.000	1.000
Balance of system						
Foundations	46	112	0.000	0.000	0.404	0.404
Transportation	50	113	1.581E-05	2.000	-0.038	54.7
Roads, Civil Work	79	149	2.170E-06	2.000	-0.015	69.54
Assembly and Installation	38	135	1.174	0.000	0.000	1.000
Electrical Interface	122	239	3.490E-06	2.000	-0.022	109.7
Engineering & Permits	32	67	1.000	0.000	0.000	0.000
Total	367	815				
Total Cost (1000$)	1404	3600				
Total Cost ($/kW)	936	2000				

Table S5. Capital costs of the different turbine models adopted here.

Model	Cost ($/kW)
V90-1.8g	2000
V90-1.8	1931
V100-1.8g	2395
V100-1.8	2213
V80-2.0g	1579
V80-2.0	1643
V90-2.0g	1964
V100-2.6	1854
V90-3.0	1530
V112-3.0	2065

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Figure Captions for the Online Supplement

Figure S1. Representative Weibull wind speed distributions in comparison to a typical wind turbine power curve, where Case 1 is derived using c = 8 m/s and k = 1.6 and Case 2 using c = 12 m/s and k = 1.6.

Figure S1. Power curves (normalized by peak power) for the 10 turbines that were considered here. Source: Brochures for each turbine model from the manufacturers website, www.vestas.com, accessed 5 February 2012.