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Optimizing renewable energy, demand response and energy storage to replace conventional fuels in Ontario, Canada

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ABSTRACT

Electricity systems with high penetrations of renewable energy require a mix of resources to balance supply with demand, and to maintain safe levels of system reliability. A load balancing methodology is developed to determine the optimal lowest-cost mix of renewable energy resources, demand response, and energy storage to replace conventional fuels in the Province of Ontario, Canada. Three successive cumulative scenarios are considered: the displacement of fossil fuel generation, the planned retirement of an existing nuclear reactor, and the electrification of the passenger vehicle fleet. The results show that each of these scenarios is achievable with energy generation costs that are not out of line with current and projected electricity generation costs. These transitions, especially that which proposes the electrification of the vehicle fleet, require significant investment in new generation, with installed capacities much higher than that of the current system. Transitions to mainly renewable energy systems require changes in our conceptualization of, and approach to, energy system planning.

1. Introduction

Renewable energy offers the opportunity to shift away from carbon-emitting fossil fuels, thereby reducing future global warming and its adverse consequences. Some authors have postulated that the size of the available renewable energy resource is more than sufficient to meet current demand [21,31]; however, there is concern that excessive fossil fuel back-up generation will still be required in order to accommodate the variable output from renewable energy sources, such as wind and solar PV (photovoltaics) [3]. Load-management techniques, like demand response and energy storage, can help to smooth fluctuations in supply and demand, increasing system reliability on a variety of time scales.

An increasingly large body of literature assesses the viability of integrating high levels of intermittent renewable energy sources into energy systems. Hart et al. [19] review renewable energy grid integration studies, classifying these studies into three classes. Zeroth-order studies use long-term average resource availability to quantify resource potential. First-order studies use time-series demand and resource data to perform load balancing simulations. Second-order studies incorporate forecasting and uncertainty in resource availability into the analysis, which allows for more detailed commentary on system reliability.

There are many recent examples of zeroth- and first-order studies. Zeroth-order studies include assessments of the installed capacities necessary to provide all power from wind, water, and sun for the world [21,31] and for New York State [30]. First-order studies of 100% renewable electricity systems have been conducted for New Zealand [33], Australia [14], and the PJM regional grid in the US [5]. Other first-order studies have assessed 100% renewable energy systems (incorporating electricity, heat and transportation), notably for Denmark [34] and Ireland [7]. There are fewer existing second-order studies due to the more complex forecasting and stochastic modeling requirements, though Hart and Jacobson [20] have used this approach to model high renewable penetrations in California.

First-order grid integration studies balance demand and supply for each time interval during the period of study, often hourly intervals over the course of a year. Performing a load-balancing study for a high penetration renewable energy system accomplishes two goals: first, it demonstrates that grid resources can be deployed in such a way as to meet system demands using only renewable generation. Second, which is more important from a planning and policy perspective, it gives an estimate of the likely energy cost and the mix of resources and load management techniques that would be required for such a transition. After a system framework has

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been laid out using a first-order study, that preliminary design could be further modified and improved to accommodate resource uncertainty through the use of a second-order study. The studies cited above generally find that renewable energy sources can be reliably combined to achieve high penetration levels in energy systems. Budischak et al. [5] find that the lowest-cost systems have excessive generation, up to three times greater than load during certain periods, in order to reduce the need for more expensive storage.

In general, the studies cited above assume a predetermined mix of renewable energy sources and load management techniques to assess a system's ability to meet demand [14,31,33]. Other studies have determined an optimal capacity of one generating resource, generally wind, amidst a system comprised of other resources (i.e. Ref. [7]). Some studies have optimized the mix of resources to achieve a lowest-cost solution, though these studies have not considered the potential effects of energy storage [20]. Others, which may investigate energy storage, ignore the potential for demand response [5] or the effect of aggregating geographically dispersed sites as potential strategies to smooth supply and meet demand. Furthermore, to the best of the authors' knowledge, no load balancing study for a high penetration of renewable energy has been performed for a Canadian jurisdiction.

This paper presents the findings of a study to determine the lowest-cost mix of renewable energy resources, demand response, and energy storage to replace conventional fuels in the Province of Ontario, Canada. Three sequential scenarios are assessed: 1) the displacement of natural gas power generation, 2) the retirement of the Pickering nuclear plant (one of Ontario's three nuclear generators), and 3) the electrification of the passenger vehicle fleet. A first-order, load balancing methodology is employed. The model is run using one year of hourly time-series resource and system load data as input, which yields the mix of resources that would have been necessary for a carbon-free energy system during the chosen year, the approximate cost of electricity for the resulting system, and the associated reduction in CO_2 emissions.

The key contribution of the paper is a methodology to determine an optimal mix of a diverse set of resources (mix of renewable, demand side management, and energy storage), which has not been comprehensively conducted to date. Previous papers have optimized a limited set of resources, or used predetermined capacities for some or all of the resources. Second, the paper optimizes installed capacity amongst a geographically diverse set of wind and solar input sites, which has not been used as a capital allocation strategy in previous studies. Thirdly, the paper presents findings for Ontario, Canada, which has never been the subject of this type of study.

2. Methods

2.1. Data sources and power system modeling

The model considers the following resources: nuclear, hydroelectric, wind, solar, biomass, energy storage, demand response and electricity imports and exports. Electric vehicles are also considered as a dispatchable load for the third scenario. Performance of the energy technologies is modeled using various data sources such as recorded generation and hourly time-series demand and renewable supply data. Historical demand, generation, and import/export time-series data were acquired from the Independent Electricity System Operator [29].

Nuclear energy is considered in the first scenario. Historical hourly generation is assumed to be inflexible, due to the technical and economic constraints of modulating nuclear power. Nuclear currently provides around 56% of Ontario's electricity, with an installed capacity of just under 13,000 MW. Peak demand in the Province typically varies between roughly 23,000 MW and 22,000 MW, during the summer and winter months respectively. Ontario is increasingly a summer peaking jurisdiction, as natural gas replaces electricity for winter heating and air conditioning becomes more commonplace. Ontario's most recent Long Term Energy Plan expects that the Pickering Nuclear Generating Station (3100 MW) will be closed by the year 2020 at the latest [43]. The retirement of the Pickering site is incorporated in the second and third scenarios considered here.

Hydroelectric power is considered dispatchable in the model, subject to historical supply constraints, with a 25% run-of-river component. The run-of-river assumption is less than what has been observed historically; however, as more wind and solar is introduced into the grid, the “must-run” component of Ontario's hydroelectric power is expected to decrease (Chui, personal communication). Ontario's hydroelectric capacity is expected to increase to 9300 MW from roughly 8000 MW over the next decade which is incorporated into the model [43]. The hourly output may not exceed the actual historical hourly available hydro power capacity. In consideration of seasonal water availability, hydro generation in each month is limited to the actual generation that occurred in that month, supplemented by additional generation that would arise from the additional modeled capacity. Furthermore, variation in output between each consecutive hour is subject to the maximum recorded ramp rates, also provided by the IESO (Independent Electricity System Operator). Though there has been recent discussion of expanding transmission links to neighboring provinces for firm hydroelectric power contracts [27], there are as of yet no set plans and as such these contracts are not considered here.

Wind power output is modeled using input data from six sites in Ontario. The sites are specifically selected for this study in an attempt to meet three goals: low cost, high capacity factor, and a high minimum output from the combined sites. We ran through multiple combinations of sites and metrics; the same six sites (shown in Fig. 1) repeatedly provided the best combination. Ontario already has roughly 5000 MW of wind in operation or under development; the existing and planned wind capacity is modeled as in Richardson & Harvey [46]. Wind speed data for the sites are obtained from the MERRA (Modern-Era Retrospective Analysis for Research and Applications) dataset [47]. Hourly wind speed data are available for heights of 2 m, and 10 m above displacement height, and 50 m above ground. Wind speed at the turbine hub height is extrapolated using the least-squares fitting approach described by Archer and Jacobson [1]. A constant 10% reduction in wind speed at the turbine height due to array losses is assumed.

Solar PV sites were selected from the 35 largest urban areas in Ontario, as we assume solar PV will be used on, or very close to, the site. The four urban areas with the highest capacity factors, along with the furthest west and furthest east sites, are modeled in the analysis (see Fig. 1). The highest capacity factors were chosen as we assume large solar PV developments are more likely to occur in locations that offer the best return. The eastern and western sites were included as this has been shown to increase the grid matching ability of solar PV in the Province [45]. Hourly solar radiation data are obtained from the MERRA dataset, and modeled following Richardson & Harvey [45].

The performance of biomass plants is based on that of the Province's recently retired coal plants; in Ontario, two retired coal plants have been converted to biomass (the Atikokan and Thunder Bay generating stations). The hourly available capacity for biomass plants is modeled on that of the retired coal power plants, and the biomass plants are also subject to the same ramp rate restrictions. Estimates for the amount of sustainable electricity from biomass

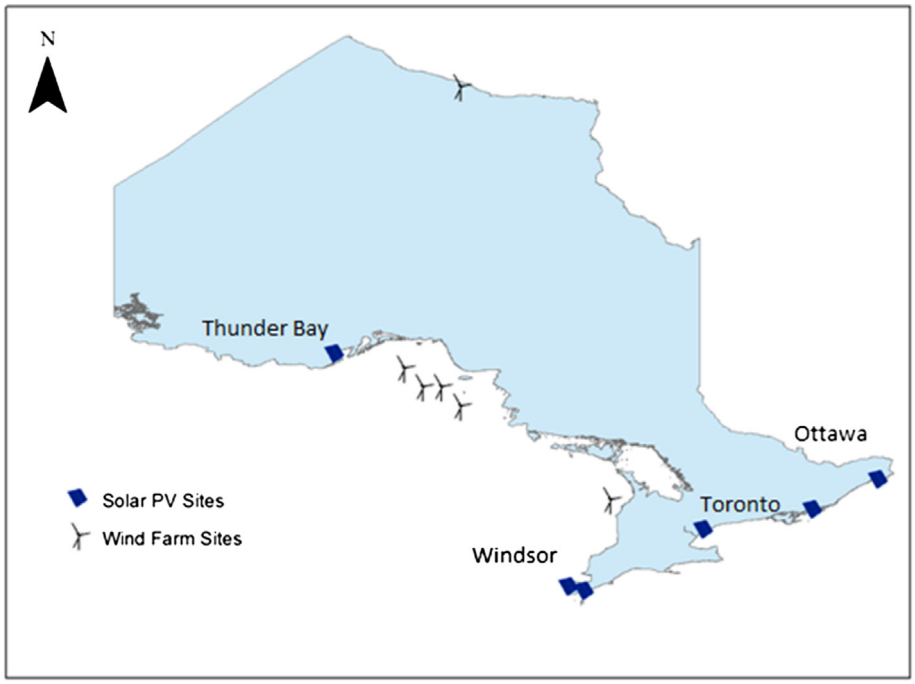

Fig. 1. Location of wind and solar sites for modeling in the Province of Ontario.

that can be produced on a yearly basis in Ontario range from 14 TWh [17] to 87 TWh [32]; by comparison, Ontario's yearly annual electricity demand is in the range of 140–150 TWh. The range in the estimates arises from differing assumptions on the roles that forest timber and energy crop production can and should play in biomass energy production. Due to concerns about the actual availability of sustainable biomass, only 15 TWh of generation per year is assumed to be available.

The dispatch strategy for demand response is adapted from two strategies described by Earle et al. [13]. Up to 90% of the total demand response capacity is assumed to be available at all times, unless it has recently been deployed, in which case it is unavailable. For every 1 kW of demand response that a customer provides for 1 h, it is assumed that the customer's demand will increase by 0.4 kW for 2 h at a later off-peak period; this results in a slight overall decrease in electricity use of 0.2 kWh. The increase in load from demand response customers must occur before 7 a.m. the following day, regardless of demand and supply conditions. Alternatively, up to 0.4 kW of this demand increase can occur during periods of excess renewable generation.

Energy from storage is available when electricity has been stored during periods of excess renewable energy for later use. There are currently 574 MW of existing or proposed pumped hydro storage in the Province, which are incorporated into the model. Since no estimates are available for the amount of pumped hydro storage potential in the Province, all other storage is assumed to be battery storage using generic battery parameter values cited in a recent review of storage technologies [12]. A round trip energy efficiency of 81% is assumed for all storage systems, with equal losses for charging and discharging. The battery system is assumed to have a daily self-discharge rate of 0.2% and 10 MWh of storage are assumed to be available for each MW of charge/discharge capacity.

The model allows for electricity exports and imports when needed, subject to existing transmission intertie constraints [28]. We assume that Ontario is able to import and export energy when there is a need. In situations where supply exceeds demand and no further electricity can be exported or stored, output is reduced first from dispatchable generators (biomass and hydro) and then from wind and solar. In the case of solar and wind energy this electricity is either spilled or curtailed (not produced). Situations where electricity cannot be exported or spilled are not allowed, as this would lead to excessive voltage and affect power quality.

For the third scenario, an EV (electric vehicle) charge plan is introduced based on a complete conversion of the passenger vehicle fleet from internal combustion engine to EVs. The number of vehicle kilometers per year comes from Statistics Canada [55]; while an hourly driving profile for the year is developed using the same method as in Richardson [44]. In Ontario, 16.1 billion liters of gasoline and 4.9 billion liters of diesel fuel are purchased for road vehicle consumption on a yearly basis [54]. At an energy density of 32.2 MJ/L and 32.8 MJ/L respectively, this is equivalent to the consumption of 189 TWh (or 680 PJ) of energy for vehicle transportation. The vehicle energy intensity is assumed to be 0.16 kWh/km, with a battery charging efficiency of 0.9 and a grid connection of 5 kW [53]. The batteries of all EVs are treated in aggregate; the aggregate battery is required to be fully charged by 7am every morning. It is assumed that all EVs are plugged-in when not driving.

Vehicle-to-grid (V2G) energy supply is allowed by the model. A vehicle discharging efficiency of 0.93 is assumed based on Sioshansi & Denholm [53]; for a round-trip energy efficiency of 0.84. Power supplied through V2G cannot be dispatched during more than 30% of the year's hours, in order to limit battery degradation. There are also limits on the daily energy provision of V2G to ensure that the EV batteries can still be fully charged by morning. Furthermore, V2G power is unavailable to the model if the aggregate state of charge is 40% or lower.

As in other similar studies [5,14], the Province's electricity system is assumed to be a 'copper-plate', meaning power can flow unconstrained to any site in the system. This aggregates regional supply and demand as well as eliminates consideration of transmission losses. While certainly a simplifying assumption, it is not expected that such an assumption will seriously affect the optimal

resource capacities or generating costs produced by the analysis, but location will affect the delivered energy costs.

2.2. Load matching algorithm

Generating sources and load management techniques are deployed in the following manner to meet demand: nuclear (for applicable scenarios), wind, solar, hydroelectric, energy from storage, demand response, biomass, and finally electricity imports. Nuclear, wind and solar energy are 'must-run'; the remaining resources and load management techniques are dispatchable, subject to ramp rate constraints. Biomass is deployed after energy storage and demand response due to the fact that biomass is assumed to be energy limited and thus best suited as a last resort peaking unit; for example, the recently converted Thunder Bay advanced biomass facility is contracted for a yearly capacity factor of just 1.5%. Strategies for dealing with excess energy supply are used in the following order: EV charging (if available), other energy storage, increased demand from demand response customers, electricity exports and energy curtailment (or spillage). Spilled electricity is subtracted from the hourly output first from dispatchable resources and then from wind and solar if necessary.

In the model, EVs can take advantage of excess renewable generation for charging at any time. If daytime excess electricity is not enough to charge the aggregate EV battery, charging begins at 9 p.m. to evenly distribute charge over the night-time hours. The charge rate can increase if there is excess renewable generation. If demand exceeds supply after all resources have been deployed and there is scheduled EV charging, the charge rate can be reduced provided there are sufficient hours remaining before 7 a.m. to completely charge the EV batteries. Alternatively, if load exceeds supply, EVs can provide electricity through V2G provision.

2.3. Costs

The *LCOE* (levelized cost of electricity) for each resource is calculated on a per MWh basis using Equation (1),

$$LCOE = \frac{CRF \times C_{cap} + OM_{fixed}}{8760 \times CF} + OM_{\text{variable}} + \frac{C_{fuel}}{\eta}, \tag{1}$$

where *CRF* is the cost recovery factor based on a 5% interest rate and 25 year project life (15 years for demand response), C_{cap} is the capital cost (\$/MW), and *CF* is the capacity factor. Operations and maintenance (O&M) costs are subdivided into fixed costs, OM_{fixed} (\$/MW/year) and variable costs, $OM_{variable}$ (\$/MWh), while C_{fuel} is the cost of fuel (\$/MWh) and η is the efficiency of generating electricity from that fuel. The fuel cost for storage is based on the assumption that relatively cheap, off-peak electricity will be purchased at the market clearing price determined by the IESO. The assumed cost (in \$CAD) for each resource is shown in Table 1.

Capacity factors are based on the modeled performance of the resource, which give rise to the per-MWh costs for each generating source, determined in the model. As in Harvey [22]; cost multipliers are used to account for offshore and remotely located wind farms. The capital cost of offshore wind sites is an additional 50%, while remote northern sites above 50° latitude cost an additional 25% to construct. The transmission cost of remote wind sites is added to the capital cost of the new wind sites. We assume high-voltage AC lines costing \$1.2 million/km for distances less than 750 km and high voltage DC lines costing \$1.55 million/km for distances greater than 750 km. Offshore transmission is estimated to cost \$7.2 million/km, with transformer stations costing \$0.24 million per MW. We also assume a 40 year life span and a fixed O&M cost equal to 1% of the capital cost.

A constant cost of \$65/MWh for nuclear electricity (based on data from Refs. [4,39,40]) is assumed. The nuclear energy costs above are lower than those of an equivalent newly constructed plant, as these resources have already been built, so the largest cost components are the cost of fuel and variable O&M. Existing wind energy is paid \$115/MWh, which is the feed-in tariff rate for wind energy in Ontario, while all new wind energy is paid at its levelized cost using the cost assumptions in Table 1. A constant cost of \$90/MWh [38] is assumed for electricity imports. Electricity exports in Ontario are priced at the hourly market rate. Finally, a constant cost of \$124/MWh for V2G power is used, based on Richardson [44].

Except for newly built wind energy, system costs arising from transmission infrastructure and transmission energy losses are not accounted for in this analysis. We assume that all newly built solar, biomass, storage and demand response will be situated close to existing transmission connections and load centres.

2.4. Analysis and optimization

Analysis is performed using hourly data from January 1, 2012 to December 31, 2012. The objective function is the average levelized cost of electricity as calculated in Equation (2),

$$LCOE_{average} = \left(\sum_i LCOE_i E_i - p_e E_e \right) \Big/ \left(\sum_i E_i - E_e \right), \tag{2}$$

where $LCOE_i$ is the calculated LCOE of each resource, E_i is the energy produced by each resource, p_e is the price for electricity exports and E_e is the amount of exported electricity. Exports are weighted negatively; the revenue generated from electricity exports reduces the average cost, but exported energy is not counted in domestic production, which tends to reduce the denominator and increase the average cost.

The optimization goal is to minimize the LCOE, subject to the constraint that supply is equal to demand for every hour. The model searches for an optimal solution by changing the installed capacities of each of the resources under consideration. The model is solved using a Nelder-Mead simplex algorithm [61] to determine the optimal combination of resources. This algorithm was found to converge on a solution faster than many other more complex optimization approaches. The optimization model was run for a range of initial conditions with convergence on the final optimal results. Fig. 2 displays a graphic of the overall model.

The reduction in carbon emissions (measured in tonnes of CO_2 equivalent) for each scenario relative to the present-day situation is calculated as well. We selected the median values of life-cycle emissions per unit of energy generated from the latest IPCC (Intergovernmental Panel on Climate Change) report [49]. We assume an energy use rate of 1.68 MJ/km and 0.62 MJ/km for internal combustion engine vehicles and electric vehicles, respectively [26]. For vehicle lifecycle emissions related to vehicle production, we assume 35 gCO_2e/km for internal combustion engine vehicles and 45 gCO2e/km for electric vehicles [23].

The capacity credit for wind and solar power is calculated for each scenario. The capacity credit of a generator indicates the amount of dispatchable generation that can be replaced by that generating unit. Previous work has found that the capacity credit of solar PV in Toronto, Ontario is around 40% of installed PV capacity at low grid penetrations [41]; this means that for every MW of installed solar PV, 0.4 MW of dispatchable generation can be retired. Following the recommendations of Hoff et al. [25]; a modified version of the Garver approximation [18] is used to determine *CC* (capacity credit), namely,

Table 1
Assumed costs for each resource.

Resource	Capital cost ($/MW)	Fixed O&M ($/MW)	Variable O&M ($/MWh)	Fuel cost ($/GJ)	Efficiency
Wind	1.6×10^6 [a]	9.1×10^4 [b]	9[a]	0	
Biomass	2.0×10^6 [b]	5.5×10^4 [c]	5[c]	8.2[c]	0.31[c]
Solar	1.9×10^6 [d]	3.8×10^4 [e]	0	0	
Demand response (residential)	5.2×10^5 [f]	2.6×10^4 [f]	0	0	
Demand response (commercial & institutional)	1.7×10^5 [g]	1050[g]	0	0	
Storage (pumped hydro)	1.7×10^6 [h]	2.5×10^4 [e]	5	20 ($/MWh)[k]	0.8
Storage (battery)	1.8×10^6 [i]	3.8×10^4 [i]	5[i]	20 ($/MWh)[k]	0.8
Hydro	4.4×10^6 [j]	1.4×10^5 [j]	0	0	

[a] From Ref. [60].
[b] From Harvey, Energy and the New Reality 2: Carbon-Free Energy Supply [21].
[c] From Ref. [62].
[d] From Ref. [6], 2020 projection for utility scale solar.
[e] From Ref. [24].
[f] Based on data from Ref. [8,50,54].
[g] Based on data from Ref. [9,37].
[h] Based on proposed pumped hydro project in Ontario [36].
[i] From Ref. [58].
[j] For new-built hydro, based on [11].
[k] Assumed marginal cost of electricity to be purchased for use in storage.

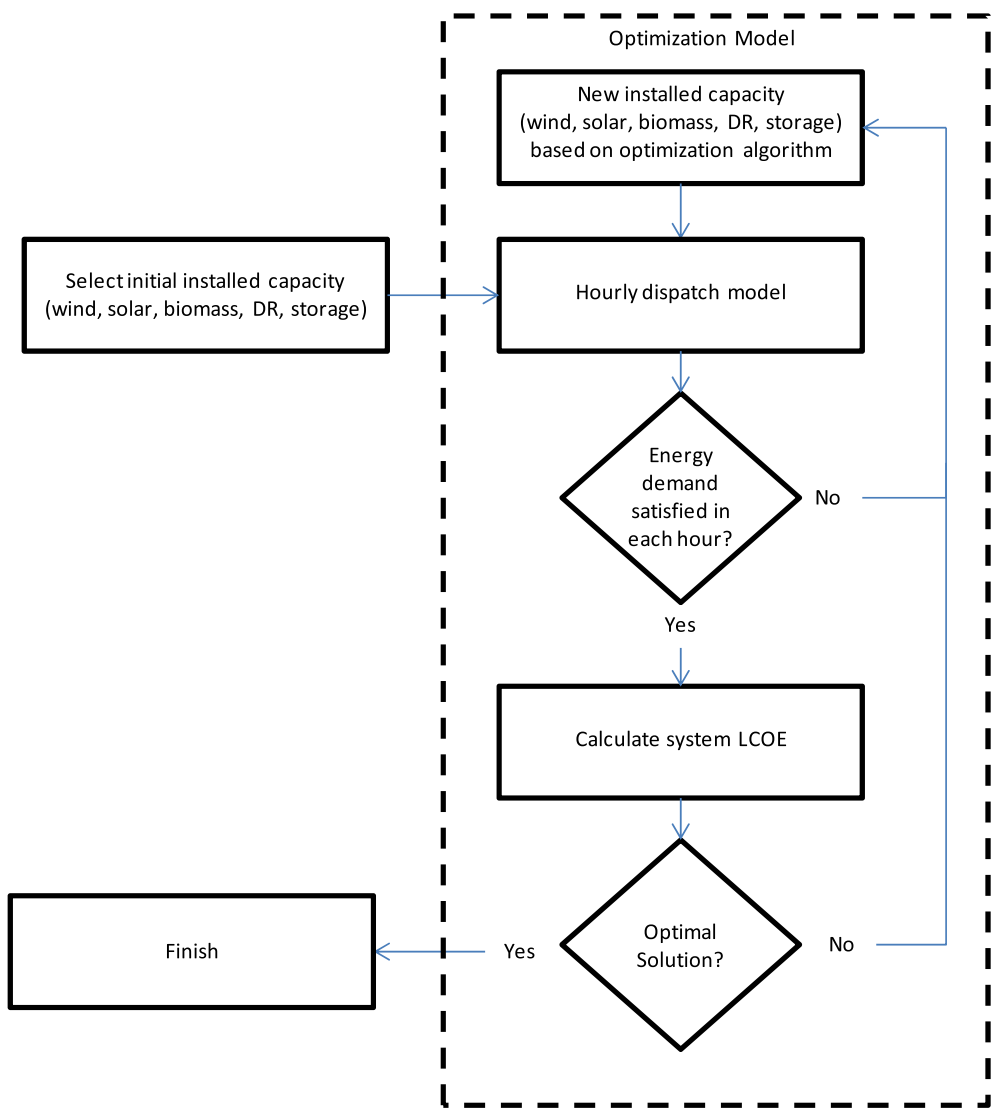

Fig. 2. Model design.

$$CC = m \ln\left[\frac{\sum_i\{\exp(-(L_P - l_i)/m\}}{\sum_i\{\exp(-(L_P - l_i + x_i)/m\}}\right] \Big/ X, \quad (3)$$

where L_P is peak load, m is the Garver coefficient set to equal $0.03L_P$, l_i is the load at hour i, X is the capacity of the new generator, and x_i is the output or availability of the new generator at hour i.

3. Results & discussion

The levelized cost of energy, electricity exports and carbon reduction results for the three scenarios are displayed in Table 2. CO_2 reductions are calculated for the total electricity system emissions plus passenger vehicle emissions, which account for approximately 75% of total emissions. The exports increase significantly through the different scenarios, as larger amounts of intermittent renewables (mostly wind) are brought into the grid. The total capacity and total generation for each scenario are given in Figs. 3 and 4 respectively. There is a slight increase in carbon emissions between Scenario 1 and Scenario 2, as the Pickering nuclear plant is largely replaced by wind, which has the same life-cycle emissions rate, as well as solar and biomass, which have higher life-cycle emissions rates. There is a significant reduction in CO_2e when the passenger vehicle fleet is converted to electric power in Scenario 3. The primary conclusion from the results is that it is possible to match demand and supply while transitioning to a fossil fuel-free electricity and personal transportation system. The generation costs produced by the analysis are not out of line with current and projected electricity generation costs, especially for the first two scenarios. The LCOE increases for each successive scenario as there is a higher reliance on more expensive wind and solar power. This includes a substantial jump in costs when a large amount of new capacity must be built to accommodate the extra electricity demands from electric vehicles. In this scenario, the existing energy production from the system is insufficient to meet the additional needs due to vehicle energy demand.

The model results in a wind-dominated electricity system, due to the relatively low cost of wind electricity. In the third scenario, wind provides 75 TWh, over 50% of demand and close to Ontario's current output from nuclear power plants. Interestingly, hydro power appears to be squeezed out of the supply mix, providing between 14 and 20 TWh in the modeled scenarios; the yearly limit on hydro supply is 38 TWh. The underutilization of hydro power is a function of the load matching algorithm; nuclear, wind and solar are considered must run, while hydro is deployed to fill in when needed, resulting in a lower capacity factor than technically allowable. The surplus baseload hydro power does not appear as spilled electricity. Instead, the water isn't used for power, just spilled past over the dam. One of the consequences of high wind and solar penetrations is that it relegates hydro power to primarily a peak-shaving and backup power source. Unless there is sufficient hydro storage capacity (as in the case of Norway in relation to Denmark), the water can't be kept and that energy is lost.

The impact of wind and solar on hydro production is best demonstrated visually. Fig. 5 shows the energy demand and supply mix for the week of August 5–12th, a high demand week with large fluctuations in wind power production. Fig. 5a and b give the results for the second and third scenarios, respectively. In Fig. 5a, fluctuations in wind power are largely balanced by hydropower; there are periods when no hydro power is required, which results in spilled run-of-river hydro. In Fig. 5b, with much greater production from solar power, there is correspondingly less hydro power. The change in demand profile is a result of EV charging increasing the total demand. In this week, EV charging occurs during periods of high solar power production. The difference in hydropower between the two figures illustrates the impact of increased solar and wind penetration on hydro power production.

Previous work had found that the technical limit for solar PV in Ontario was an annual supply contribution of 8–20%, depending on the grid conditions (Richardson & Harvey, In Progress). In this study, solar PV provides 15.9% of annual supply in the third scenario, which is in line with our previous analysis.

Biomass capacity, by design of the load-matching algorithm, is used essentially as back-up and peaking generation; the capacity factors (ratio of actual output to full nameplate output over the study period) for all three scenarios are in the 3–11% range.

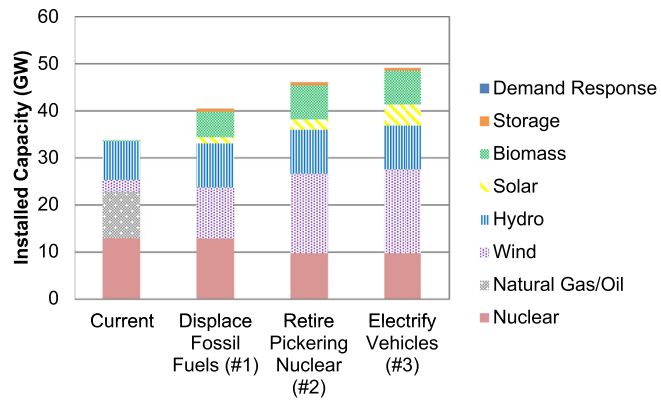

Fig. 3. Generating capacity for each scenario.

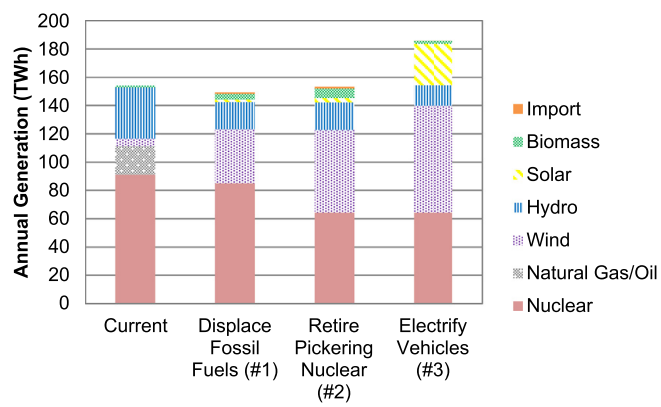

Fig. 4. Total generation by source for each scenario.

Table 2
Levelized cost of electricity, electricity exports, CO_2 emissions reduction, and spilled electricity for each scenario.

	Displace fossil fuels (#1)	Retire pickering nuclear (#2)	Electrify vehicles (#3)
LCOE ($/MWh)	83.6	88.8	109.8
Exports (TWh)	8.2	12.2	24.0
CO_2 reduction (%)	6.2%	5.4%	72.8%
Energy spilled (TWh)	0.1	1.1	17.9

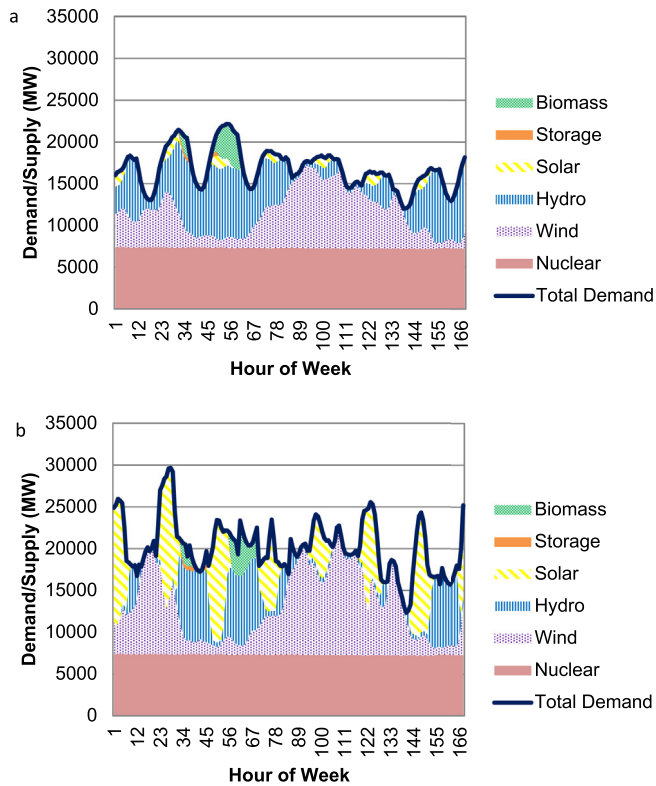

Fig. 5. Demand and supply mix, August 5–12th, 2012 for a) Scenario 2 (retire pickering nuclear) and b) Scenario 3 (electrify vehicles).

Capacity factors for all non-nuclear resources are given in Fig. 6. A substantial installed capacity, over 7 GW in Scenarios 2 and 3, is required in order to accommodate large changes in wind and solar output. The biomass generation limit of 15 TWh/year imposed on the model is never met under any of the scenarios; the maximum biomass electricity production is 6.7 TWh. It may be cost effective to allow more bioenergy production at the expense of solar and wind if the biomass capacity is already being installed for back-up capacity.

Energy storage capacity is 574 MW for all three scenarios, while demand response ranged from 1 to 16 MW, compared to a total installed supply capacity ranging from 40 to 49 GW. Thus, energy storage and demand response were not extensively employed by the model. Installed energy storage capacity was barely higher than the minimum 574 MW attributed to existing and planned pumped hydro storage, due to the relatively high costs of storage compared to generation. Demand response is not employed by the model because the use of demand response results in an increase in demand later in the day; it is possible that different assumptions about demand response may lead to greater use of demand response in modeled scenarios.

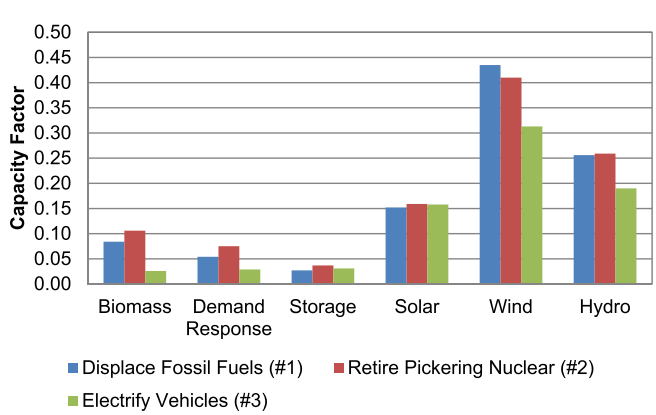

Fig. 6. Capacity factors for non-nuclear resources.

It should be noted that total generation decreases from Scenario 1 to Scenario 2 despite no change in demand. This is due to higher electricity exports in Scenario 1, which has roughly the same installed capacity of wind and solar, but much less demand to meet due to the baseload output of the Pickering nuclear plant.

Overall, the results are consistent with previous studies (i.e. Ref. [5]) which prescribe significantly higher system capacity when compared to peak load. The total installed generating capacity in Scenario 3 is almost 50 GW, including 18 GW of wind capacity (for comparison, Ontario's current capacity is roughly 36 GW). The need for the extra capacity is a function of the low capacity credit of wind and solar power, due to the variable production of the two resources. The capacity credit of a generator indicates the amount of dispatchable generation that can be replaced by that generating unit. For example, if the capacity credit of solar PV is 0.4, this means that for every MW of installed solar PV, 0.4 MW of dispatchable generation can be retired. Fig. 7 displays the load duration curves for wind, solar and combined for the second and third scenarios, and Fig. 8 gives the capacity credit for each resource. Fig. 7 shows that each resource produces at peak for only a small fraction of the year, with energy production below 25% of peak for over 20% of the hours of the year. The combined output from wind and solar in Fig. 7b displays a more gradual decline than wind and solar individually. Solar power has a capacity credit of 27–31%, while the capacity credit of wind is between 15 and 19%. As a result, a much greater installed capacity is required to replace gas and nuclear units, which have capacity credits upwards of 85%.

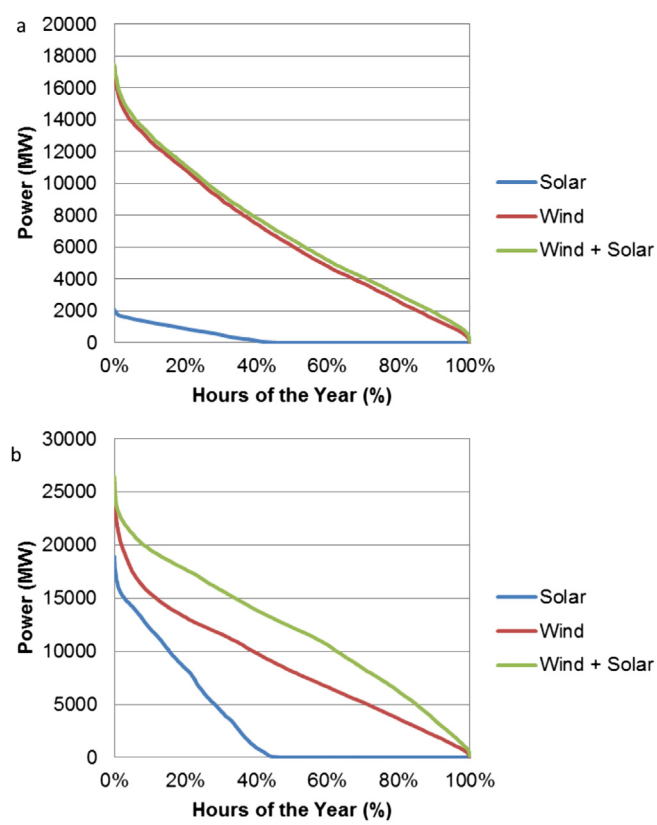

Fig. 7. Wind and solar load duration curves for a) Scenario 2 (retire pickering nuclear) and b) Scenario 3 (electrify vehicles).

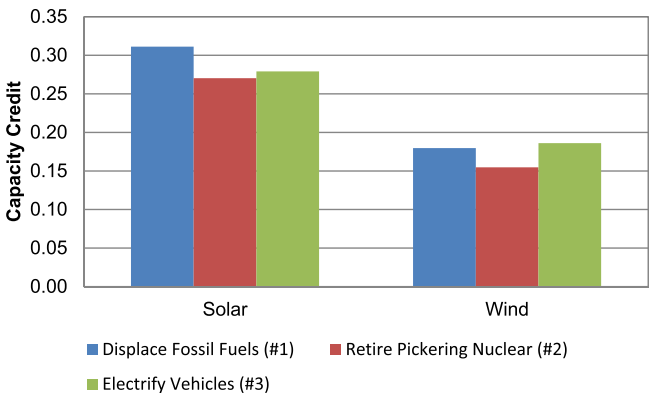

Fig. 8. Capacity credit for wind and solar.

These results indicate that the transition to an energy system with a high penetration of renewables will require changes in the way we approach and plan the system itself. Significant excess capacity, in the traditional sense, may be required to overcome the intermittent production of solar and wind. The downside of this is excess electricity production: in Scenario 3 roughly 10% of total generation is spilled. An upside may present itself in the presence of excess electricity; since the cost of producing this energy has already been accounted for, any revenue gained by selling rather than spilling the excess energy will reduce the average cost to customers. This may foster innovation in alternative uses for electricity, such as hydrogen electrolysis.

4. Conclusion

A first-order grid integration study for three successive scenarios is performed for the Province of Ontario, Canada. The goal of the analysis is to provide estimates of the optimal combination of renewable energy, demand response, and energy storage resources that would be required to replace conventional energy generation in Ontario's power and private transportation sectors. High-level estimates are useful for policymakers in determining the plausibility of meeting policy goals, and the scope of investment and change that would be required to meet those goals. The analysis presented in this paper provides an initial estimate of how to displace fossil fuels and nuclear power as an energy sources in the Province. One area for future work that should be included is to expand the scope of study to not only include power generation and transportation, but home heating fuels as well.

The results indicate that system reliability can be maintained without excessive generation costs as we move away from fossil fuels for electricity generation and passenger transportation, and that such a transition is technically feasible. Electrification of the passenger vehicle fleet requires substantial investments in new capacity, including what we would traditionally define as excess capacity. With these thoughts in mind, it is clear that the transition to a system comprised mainly of renewable energy is not only a problem of providing new electricity supply. It is equally, if not more, a problem that confronts our use of, and demand for, electricity, one which will shape our habits and the technologies that we use.

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