Integration Of Wind Power into An Electricity System Using Pumped Storage: Economic Challenges and Stakeholder Impacts

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Development Discussion Paper: 2023-07

ABSTRACT

The Province of Ontario has had an aggressive program of introducing wind electricity generation technologies into its generation supply mix. This, combined with the rigid baseload production by nuclear and hydro plants, has created a situation where a surplus baseload electricity supply is projected for the next 20 years. Pumped hydro storage (PHS) is suggested as an economically viable technology for storing energy from non-dispatchable wind energy sources in the baseload period to be used the generate electricity in peak periods. An analytical framework has been developed to explore the feasibility of the PHS facility and to compare its cost with that of alternative gas power plants. Two situations are analyzed. First, the PHS plant uses only surplus energy for the first 20 years of operation and then is retired from the system. Second, an additional 20 years of PHS usefulness is added by making investments in wind electricity generation to provide energy for pumping. Given the capital costs of building PHS in Ontario, the conclusions of this study suggest that a PHS facility is not economically cost-effective for utilizing the projected off-peak surpluses. The economic analysis also illustrates that in the context of Ontario, the integration of PHS with wind power generation will have a further negative impact on the Canadian economy in all circumstances. This loss is borne mainly by the electricity consumers of Ontario. Even considering the cost of CO_2 emissions from a world perspective, this investment is not cost-effective. It would be much better socially from a world perspective and economically from Canada's perspective if the surplus baseload electricity from Ontario were given away free to the USA. It could then be used to reduce generation by natural gas plants in the USA, hence reducing CO_2 emissions globally, without any incremental economic cost to Canada.

Keywords: Economic analysis, Electricity, Ontario, Pumped hydro storage, Wind power

JEL Classification: O55, D61, Q42

ACKNOWLEDGMENTS
Financial support for this research was provided through a Mitacs Accelerate-PDF Fellowship [IT13680].

1. INTRODUCTION

Variable electricity generation sources such as wind and solar are frequently seen as critical elements of future low-carbon energy systems. To enable their widespread adoption, however, the output of these technologies must be reconciled moment by moment with the relatively unresponsive energy demand. A larger share of power generated by renewable energy sources requires higher grid flexibility to ensure the electricity system's reliability (Van Kooten, 2016). This problem poses a significant challenge to using non-dispatchable renewable electricity generation for many countries (Lacerda & van den Bergh, 2016; Brown et al., 2018). Such renewable energy sources impose a number of documented externality costs on the electrical grid (Benitez et al., 2008), attributed mainly to maintaining thermal generation capacity and backup reserves to be ready to operate when the supply of electricity from renewable generation drops.

A vast body of literature highlights the potential energy storage capabilities to offset the intermittency of the output generated by renewable energy sources. All sources seem to agree that energy storage can be considered a possible solution to accommodate supply-side variability and the uncertainty of power generated by renewables (Bélanger & Gagnon, 2002; Korpaas et al., 2003; Castronuovo & Lopes, 2004; Bermúdez et al., 2014). Energy storage is viewed as essential for efficiently implementing higher capacity in non-dispatchable renewable electricity generation. Among the available types of energy storage, pumped hydro storage (PHS) is a proven technology that has been utilized for over a century (Spyrou & Anagnostopoulos, 2010; NREL, 2012; Saini & Gidwani, 2020). Many studies, such as Evans et al. (2012) and Ming et al. (2013), highlight that PHS is a mature form of energy storage technology holding about 99% of the world's total storage capacity (Chatzivasileiadi et al., 2013), with an efficiency range of 70–85% (Hadjipaschalis et al., 2009).[1]

Substantial research has demonstrated that PHS is a viable storage option in some circumstances where it complements investments made in renewable power sources and plays a significant role in a grid-scale renewable energy scheme (Papaefthymiou & Papathanassiou, 2014).[2] PHS can address the natural and unpredictable fluctuations in wind and solar energy generation by fast ramping with a relatively wide operating range, making it suitable for balancing wind and solar generation with system demand. In periods when the grid faces an oversupply of electricity, the PHS potential of storing can utilize the surplus electricity, avoiding costly shutdowns of both wind turbines and conventional thermal generators (Yang et al., 2008).

PHS technology is currently deployed in Canada, Western Europe, the USA, and Japan (Ma et al., 2014). Caralis et al. (2014) suggest that PHS can be considered the most appropriate storage technology for allowing high wind penetration levels. PHS capacity is projected to increase by approximately 20% by 2020 in the EU to complement intermittent renewable energy sources (Punys et al., 2013). The potential of the PHS system is also being reconsidered by policymakers in the USA (Yang & Jackson, 2011).

Some studies (such as Carrasco et al., 2006; Ibrahim et al., 2008; Levine, 2007; and Manolakos et al., 2004) have demonstrated the feasibility of PHS for remote renewable energy power supply. However, the challenges for this technology are site availability and possible eco-environmental problems (Ma et al., 2014).

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[1] Efficiency here refers to the percentage of a kWh of electricity that can be generated by the PHS plant per kWh of electricity used as an input to the operation of the PHS plant.
[2] The World Bank IEG group (2020) found that the most critical technology explicitly developed for electric-energy time shift is pumped storage. In 2017, about 89% of the PHS installed capacity was utilized for electric-energy time shift purposes.

One important question is whether the minimum efficient scale of the pumped storage facility will be cost-effective to store surplus energy from a given set of renewable generation plants. Chang et al. (2013) and Ibanez et al. (2013) investigated the use of hydroelectric generation with storage reservoirs to support variable renewable generation in California and the Western Electricity Coordinating Council (WECC) regions, respectively. They show that the system-wide costs and emissions are reduced by integrating storage dam hydropower and wind power resources. These studies also find that dispatching hydroelectricity to support renewable generation enables higher penetrations of renewables and minimizes the frequency of curtailment events. However, despite PHS's pivotal response to demand variability and other possible advantages (Rehman et al., 2015), the economics of pumped storage must be better understood for its development to be feasible to complement or integrate with renewable energy generation.

The financial profitability of PHS when its compensation comes via electricity markets is highlighted in many studies as its primary obstacle. This issue has been discussed for the six proposed PHS plants in Norway, and the results show that all were not profitable (Ingebretsen & Johansen, 2014).

In contrast, Zafirakis et al. (2013) indicate that PHS accompanied with a "socially just" feed-in tariff (FIT) can be cost-effective.[3] The main question here is how PHS development affects system cost and, therefore, the nature of the economic outcome of adding storage capacity. As highlighted by Bradbury et al. (2014), this issue can be addressed by providing adequate economic information. Besides, electricity market deregulation also provides competitive room for relevant hydro developers while challenging their profit maximization scheme.[4] Hence, there is a need to

[3] This projection might be of interest to Ontarians. Ontario is already home to Ontario Power Generation's 174 (MW) pumped storage facility, the Sir Adam Beck Pump Generating Station (SAB) which is not found to be eligible for FIT rates (see Tahseen & Karney, 2016).

[4] Salevid (2013) reports the high degree of dependency between energy price volatility (during on- and off-peak hours) and PHS profitability in Sweden. This might be a similar challenge to the current Ontario PHS (SAB) and any other new PHS. The FIT in

investigate PHS's potential as the most cost-effective storage option for electric utilities to consider.

There are many empirical studies that assess the financial feasibility of PHS (for instance, Mitteregger & Penninger, 2008; Nazari et al., 2010). To our knowledge, however, no fundamental applied research is available to determine the economic feasibility and, most importantly, the stakeholder impacts of this possible solution for complementing the investments already made in non-dispatchable electricity generation such as wind power. The stakeholder analysis brings into focus the effects of PHS integration in combination with wind power on the different groups in society. Such quantification of the stakeholder impacts provides the basis for designing policies that address stakeholder concerns. This is an essential subject for Ontario, which is Canada's leader in wind generation. In 2021, Ontario had an installed capacity of 5,076 MW, about 40% of Canada's total installed wind energy capacity (Bahramian et al., 2021b).

Ontario's baseload generating resources often provide more energy output (i.e., supply) than is demanded in the province, resulting in surplus baseload generation (SBG). When there are willing buyers, SBG can be resolved by exporting surplus energy to neighboring jurisdictions. Typically, in hours of SBG, when nearly all surplus supply is coming from resources with low or zero marginal cost, prices will tend toward zero or become negative. Furthermore, when SBG is greater than the intertie capacity with other markets (or when adjacent markets are already sufficiently supplied by low marginal cost generation), the Independent Electricity System Operator (IESO) must curtail electricity production from specific plants, predominantly hydroelectric and wind generation. In 2016, Ontario exported 14.6 TWh of clean energy at a loss of over CAD 384 million. From September 2018 to September 2019, the province curtailed

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Ontario leads to a higher wind capacity, increasing the availability of low-cost, off-peak electricity and reducing electricity prices, resulting in a lower overall profit opportunity (Linares et al., 2008).

approximately 2.9 million MWh of electricity (ERM, 2020). The possibility of PHS electricity arbitrage[5] could, however, result in a significant portion of the installed baseload generation capacity in Ontario continuing to generate in hours when demand and market clearing prices are low in order to increase electricity generation in the high-value peak periods.

In addition to Ontario's current operational SAB pumped storage facility, TC Energy recently proposed a PHS unit to provide 1,000 MW of generation capacity. The project is designed to operate over a range of outputs with high ramp speeds and fast start-up capabilities (Navigant, 2020). It is intended to store the excess electricity (usually exported at a loss or wasted by curtailment) and meet the need for additional required capacity for the province's future energy demand. Therefore, in this study, integrated analysis is conducted, including financial, economic, and, most importantly, stakeholder analysis, to examine the multiple impacts of this new proposed PHS facility with wind power. In addition, the feasibility of the examined PHS is also compared with the traditional alternative technology of single-cycle natural gas power plants for supplying electricity to meet the peak period demands of consumers.

Previous studies (Bahramian et al., 2021a; Bahramian et al., 2021b) have shown that Ontario's green policies have, to date, been highly inefficient. It has not been possible to fully integrate wind power into Ontario's electricity supply system, which is dominated by nuclear power generation and limited storage hydropower. Thus, examining the wind-PHS feasibility from an integrated investment appraisal perspective should be of significant interest to Ontario's grid authorities. The careful consideration of the results of the analysis may guide the future decisions

[5] Arbitrage is buying a good in a low-price market and selling it in a higher price market and earning the spread between the two. In the context of PHS facilities, this means storing electricity in low-price hours and selling that stored energy later when prices are higher.

of relevant policymakers. The economics-based stakeholder analysis developed in this study can also serve as a framework for future policy research in the field of electricity storage.

The paper proceeds as follows. Section 2 gives an overview of the evaluated PHS, section 3 discusses the methodology, section 4 provides the empirical results, and section 5 concludes the paper.

2. ONTARIO PUMPED STORAGE PROJECT

One of the critical policy questions facing Ontario's electricity planners is how to meet its future electricity demand following the anticipated closure of the Pickering Nuclear Generating Station in 2024. The IESO estimates that between 2,000 and 3,000 MW of new generation capacity will be required[6] starting in 2025 and increasing slowly through 2040 to meet its future long-term demand (Navigant, 2020). Ontario also has a number of aging gas-fired units. Some will likely be retired as their contracts expire through the 2020s and 2030s. Hence, a number of new gas-fired generation plants are being built.

In this regard, TC Energy proposes to develop a large-scale hydroelectric pumped storage power project in Southern Ontario, inside the property of the Department of National Defence (DND) 4th Canadian Division Training Center north of Meaford, Ontario. The project aims to store and conserve a substantial portion of the SBG[7] and dispatch it when needed. This pumped storage plant would reduce the need for gas-fired power generation, resulting in lower greenhouse gas emissions. The project also builds resilience into Ontario's electrical system as a dependable resource that can be called upon to respond quickly to changing system demand, generating power

[6] This estimate interval assumes that all existing generation resources continue to operate after their contracts expire.

[7] It should be noted that the Ontario SBG levels are projected to decrease following the refurbishment and retirement of some nuclear units. However, without energy storage, more renewable generation to further decarbonize the power sector will likely create more frequent SBG conditions. Incorporating grid-scale storage into the system to shift SBG to demand periods is a promising option to optimize existing resources and enable additional renewable development.

in the event of an unforeseen outage or absorbing excess generation as a result of unexpected demand fluctuations (ERM, 2020).

The CAPEX of the project has been estimated to be USD 2.6 billion (in nominal value), or USD 2,433 per kW in constant prices of 2021. These capital costs per kW of capacity are close to the upper level of the range of USD 617 to 2,465/kW for PHS provided by IRENA (2020).

The PHS is configured to provide flexibility to IESO system operators with the planned capabilities of three 333 MW units providing 1,000 MW of pumping and generation for 8 hours (or 8,000 MWh of energy storage). It would have the ability to start and stop multiple times per hour without restriction and to switch from pumping to generation with an estimated 72% efficiency (Navigant, 2020). The planned in-full-service date of the project is expected to be in 2028 (Navigant, 2020).

3. METHODOLOGY

A typical standard PHS facility includes two water-filled reservoirs linked by a tunnel (penstock), a powerhouse with a pump/turbine, a motor/generator, and a transmission connection (Figure 1). PHS functions by pumping water from a lower reservoir using surplus electricity (usually generated during periods of low electricity demand, typically at night) to an upper reservoir. The water from the upper reservoir is released (during a high demand period) to generate electricity by driving a turbine. The pump used to move water to the upper reservoirs becomes a turbine when the water is released downward. The motor used to pump water to the upper reservoir becomes an electricity generator when the water is released from the upper reservoir down the penstocks.

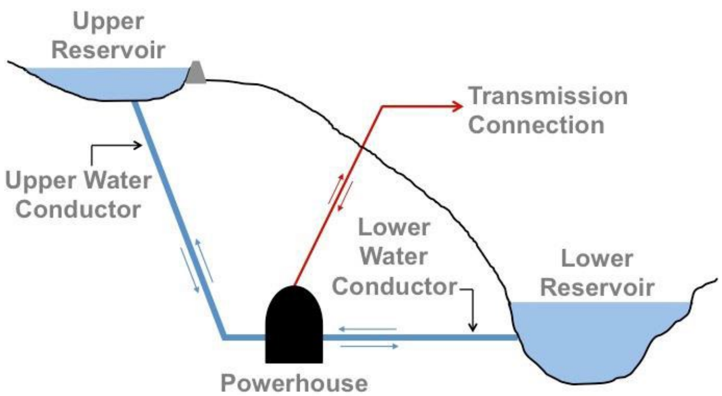

Figure 1: Schematic of a Typical PHS Facility (Source: Koritarov et al., 2014)

In the traditional mode of operation, PHS plants follow a daily operational cycle (Botterud et al., 2014). The upper reservoir is filled using off-peak energy and electricity generated by releasing this water during peak demand periods. PHS has various configurations, including open-loop (one or more of the reservoirs connected to a natural body of water such as a lake) and closed-loop (reservoirs independent of natural waterways). Existing turbine technologies also offer different features and capabilities, including fixed speed, advanced speed, and ternary (Mongird et al., 2020). The flexibility of a pumped storage plant depends mainly on the size of the upper storage reservoir. The larger the storage, the more flexible is the plant to operate over either daily/weekly or seasonal periods (Farret & Simoes, 2006).

Moving from the physics of how PHS plants operate, the structure of the methodological framework considered in this study is now explained. Electricity projects' economic benefits can usually be measured using the "least alternative cost" principle (Jenkins et al., 2019, Ch 18). In this framework, the alternative cost that would have been incurred instead of the appraised project signifies the project's benefit. The surplus electricity generated with the wind (whenever the wind blows) can be stored using the PHS system and be used during the peak demand period. Thus, it is helpful to compare the PHS-wind integrated system with the combustion gas turbine as an alternative peak energy generation in Ontario. In this analysis, a very strong assumption is made that there will always be enough baseload power available on a daily basis to pump sufficient water up to the upper reservoir of the PHS. In other words, there will be a daily cycle with 365 cycles per year.

The IESO, in its recent annual planning outlook (January 2020), highlighted that over the next 20 years, SBG in Ontario needs to be managed. The useful project life of the planned PHS in Ontario is estimated at 40 years. Hence, in this study, a scenario is postulated in which, for the first 20 years, no generation plants of any type need to be built to supply energy to pump water to the upper reservoir of the PHS plant. From an economic perspective, it is assumed that both the capital and operating costs of the plants currently generating surplus power are sunk costs. Hence, the marginal economic cost of energy used for pumping is zero.

After 20 years, the PHS plant still technically has a useful life of another 20 years; however, there will no longer be any surplus baseload energy available to pump the water. At the same time, the proposed electricity system expansion plan for Ontario proposes that the current nuclear plants will be replaced by thermal plants fired by natural gas. Hence, after 20 years, a surplus of gas generation capacity will be available in the intermediate load periods (between the peak and baseload periods) that could be used to generate the electricity required to fill the PHS reservoir. The costs of electricity to be used for pumping would therefore be only the variable costs, including fuel costs of the natural gas plants. No further capital investments need to be made in the PHS. The only financial and economic costs associated with the PHS are the variable costs.

The problem with leaving the analysis at this stage is that more CO_2 will be produced because of the generation of electricity from the natural gas-fired plants to fill the PHS reservoirs. To offset these additional CO_2 emissions, it is proposed that sufficient wind generation capacity be built to generate exactly the same amount of energy as used by the PHS. In this period, gas-fired thermal plants will dominate the Ontario electricity system; hence, it is assumed in this analysis that any additional electricity generated by wind farms will reduce the generation by the gas-fired thermal plants on a one-for-one basis. The net effect of this system is that there will be no additional CO_2 emissions for electricity supply during the peak period by the PHS facility.

The net costs of supplying the peak energy via the PHS facility are simply the variable costs of the PHS and the investment costs and operating costs of the additional wind farms that will produce an equivalent amount of energy to that used to pump water to the upper reservoir of the PHS plant.

For comparison purposes, the costs are found of generating the same amount of electricity in the peak load periods as the PHS by investing in peaking gas-powered plants. This would include their capital costs, variable operating and fuel costs, and the environmental cost of the CO_2 emissions they would create. A natural gas-fired peaking plant is estimated to have a useful life of 20 years. Hence, the initial plants that begin operations in year 1 will be replaced in year 21 to provide a 40-year profile to compare with the 40-year life of the PHS plant.

To summarize, the empirical findings of this study are divided into two separate cases. In Case I, the examination of the performance of the PHS facility is solely restricted to the 20-year profile for the situation where the input energy of the PHS comes entirely from the SBG (SBG-PHS integrated system). At the end of the 20 years, the PHS would be abandoned. In Case II, the whole 40-year profile of generation by the PHS is considered. In the first 20 years, SBG energy is assumed to be available at zero cost for use by the PHS facility, and for the next 20 years, the PHS is operated with energy produced during the off-peak periods of the day by gas-fired thermal plants. At the same time, additional wind power generation could displace an equal amount of gas-fired generation. Thus, the ultimate source of electricity that the PHS will use will be the power generated by the wind power plant. This case is denoted as the SBG-wind-PHS integrated system.

3.1 Comparative analysis

To compare the performance of PHS in these two scenarios, this study utilizes the levelized cost of electricity (LCOE) framework to obtain the cost per kWh of the integrated system. The LCOE is a summary cost metric commonly applied in the literature.[8] Comparisons of the LCOE from these two scenarios are made with the LCOE of the natural gas peaking plants that could generate the same amount of energy to meet the peak demand as that produced by the PHS.

The levelized cost of an electric power generating unit, *i*, is the ratio of its total discounted costs to its total discounted generated electricity (Belderbos et al., 2017):

$$\mathrm{LCOE_i} = \frac{\sum_t \mathrm{C_{it}} * (1+r)^{-t}}{\sum_t \mathrm{MWh_{it}} * (1+r)^{-t}} \qquad [1]$$

Given the real discount rate of r, the economic value of costs ($\mathrm{C_{it}}$) here incorporates the capital cost of plant *i* in year *t*, operation and maintenance costs of plant *i* in year *t*, fuel costs of plant *i* in year *t*, and decommissioning cost of plant *i* in year *t*:

$$\mathrm{C_{it}} = \mathrm{CAPEX_{it}} + \mathrm{OPEX_{it}} + \mathrm{FC_{it}} + \mathrm{DECOM_{it}} \qquad [2]$$

In the same manner, plant *i*'s generated electricity (MWh) in year *t* is equal to $\mathrm{MWh_{it}} = \mathrm{CAP^i} * \mathrm{NOH}$, which is the multiplication of the installed capacity of plant *i* ($\mathrm{CAP^i}$) by plant *i*'s number of operating hours (NOH), where $\mathrm{NOH} = \mathrm{cf^i} * \mathrm{n_h}$, $\mathrm{cf^i}$ is plant *i*'s capacity factor and $\mathrm{n_h}$ denotes the annual number of hours (i.e., 8,760).

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[8] However, it should be noted that the LCOE usage in the context of non-dispatchable energy sources (such as wind power) must be considered cautiously. Various studies have established that this measurement can be misleading for assessing variable generation resources competitiveness (Joskow, 2011; Belderbos et al., 2017). This issue gains even more momentum for storage facilities that are supposed to be integrated with intermittent energy sources like wind and solar power (Zakeri & Syri, 2015; Jülch, 2016). While the LCOE is not an accurate measure of electricity costs in the case of non-dispatchable technologies, this problem is greatly reduced when we combine wind farms with pumped storage in the context of an electricity system with surplus baseload power or one that is dominated by gas-fired thermal generation.

3.2 Economic feasibility and stakeholder impacts

Moving to the economic feasibility of the PHS and its stakeholder impacts, the following section discusses their detailed methodological aspects.

Table of Parameters

Prices	
$\mathbf{P_t^p}$	Selling contract price of electricity (USD/MWh)
$\mathbf{P_t^{off}}$	Purchasing contract price of electricity by PHS (USD/MWh)
$\mathbf{P_t^{ng}}$	Henry Hub Gas Price (USD/million BTU)
$\mathbf{SCC_t^g}$	Social cost of carbon for gas (USD/tonne)
PHS facility variables	
$\mathbf{CAPEX_t^{PHS}}$	Annual capital expenditure for PHS facility (USD)
$\mathbf{OPEX_t^{PHS}}$	Annual operating expenditure for PHS facility (USD)
$\mathbf{FS_t^p}$	Fuel savings during peak hours (USD), calculated using: $E_t^p * HR_{ng} * P_t^{ng}$
$\mathbf{LD_t^{PHS}}$	Loan drawdown received by PHS owner (USD)
$\mathbf{DS_t^{PHS}}$	Debt service (interest and principal repayment) paid by PHS owner (USD)
$\mathbf{T_t^{inc}}$	Income tax paid by PHS owner (USD)
Wind farm variables	
$\mathbf{CAPEX_t^{wf}}$	Annual capital expenditure for wind farm (USD)
$\mathbf{OPEX_t^{wf}}$	Annual operating expenditure for wind farm (USD)
$\mathbf{DECOM_t^{wf}}$	Decommissioning costs of wind farm (USD)
Gas power plant variables	
$\mathbf{CAPEX_t^{ng}}$	Annual capital expenditure for gas power plant (USD)
$\mathbf{OPEX_t^{ng}}$	Annual operating expenditure for gas power plant (USD)
$\mathbf{DECOM_t^{ng}}$	Decommissioning costs of gas power plant (USD)
$\mathbf{HR_{ng}}$	Heat rate for gas power plant (million BTU/MWh)
Miscellaneous	
$\mathbf{E_t^p}$	Energy generated to grid by PHS during peak periods (MWh)
$\mathbf{E_t^{off}}$	Energy required to be used by PHS during off-peak periods (MWh)
$\mathbf{r}$	Real discount rate
$\mathbf{t}$	Year
$\mathbf{R_r}$	Rate of royalty paid to Alberta government on gas sales
$\mathbf{CC^g}$	Carbon emission (tonne/MWh) of combustion turbine plant

3.2.1 Economic point of view

The economic feasibility of the wind-PHS integrated system has two aspects: economic benefits and economic costs. The main benefit of introducing PHS into the system is the fuel savings of gas turbine plants during peak hours (FS_t^p). Using the PHS plant also implies savings in the capital cost ($CAPEX_t^{ng}$), operating cost ($OPEX_t^{ng}$), and decommissioning cost ($DECOM_t^{ng}$) of the gas power plants that would have been necessary to supply electricity during the peak demand periods of the year.

$$B_t^{eco} = \sum_{t=t_0}^{T=t_{20}} \left(FS_t^p + CAPEX_t^{ng} + OPEX_t^{ng} + DECOM_t^{ng} \right) \qquad \text{[Case I, 3]}$$

$$B_t^{eco} = \sum_{t=t_0}^{T=t_{40}} \left(FS_t^p + CAPEX_t^{ng} + OPEX_t^{ng} + DECOM_t^{ng} \right) \qquad \text{[Case II, 3]}$$

In Case I, the capital and operating costs are only those of the PHS. The energy costs that the pumped storage facilities use are assumed to come at a zero marginal economic cost.

For Case II, the economic costs include the capital costs of both PHS and wind power facilities ($CAPEX_t^{PHS}$, $CAPEX_t^{wf}$), and the operating cost of both power plants ($OPEX_t^{PHS}$, $OPEX_t^{wf}$). In addition, there is the decommissioning cost of the wind power plant ($DECOM_t^{wf}$).

$$C_t^{eco} = \sum_{t=t_0}^{T=t_{20}} CAPEX_t^{PHS} + OPEX_t^{PHS} \qquad \text{[Case I, 4]}$$

$$C_t^{eco} = \sum_{t=t_{21}}^{T=t_{40}} CAPEX_t^{wf} + OPEX_t^{wf} + DECOM_t^{wf} + \sum_{t=t_0}^{T=t_{40}} CAPEX_t^{PHS} + OPEX_t^{PHS} \qquad \text{[Case II, 4]}$$

Having determined both economic benefits (B_t^{eco}) and costs (C_t^{eco}), the net present value ($NPV_{t=0}^{eco}$) for the Canadian economy can be expressed as:

$$NPV_{t=0}^{eco} = \sum_{t=t_0}^{T=t_{20}} (1+r)^{-t} \left(B_t^{eco} - C_t^{eco} \right) ; \; NPV_{t=0}^{eco} = \sum_{t=t_0}^{T=t_{40}} (1+r)^{-t} \left(B_t^{eco} - C_t^{eco} \right)$$

Most of the data inputs concerning the wind power plant and gas turbine alternative are extracted from the recent report of Lazard (2020). The corresponding data for the planned PHS in Ontario is based on the information from TC Energy that is available in the feasibility study developed by ERM (2020). As discussed by Hasan (2019), the initial annual OPEX cost of the planned PHS is set at 0.5% of the initial CAPEX. Its nominal value increases by the inflation rate for each successive year.

3.2.2 Financial point of view

The proposed PHS by TC energy is now in its planning stages. If it progresses, it will be subject to several regulatory approval processes (ERM, 2020). Hence, some financial parameters are not yet finalized. However, a financial analysis is developed here to complete the estimates of the stakeholder impacts. Almost all financial assumptions utilized in this study are tabulated from the feasibility study developed by Navigant (2020).

The financial benefits that accrue to the PHS owner are (i) payments from the IESO for output generated during peak periods and (ii) the assumed equity financing of 60% of the CAPEX; hence the loan drawdown is considered a cash inflow. A FIT procurement price of CAD 125/MWh (Bahramian, 2021a) is used as the price that the PHS owner would get for selling electricity during peak hours. The electricity selling price is then projected over the facility's lifetime using the growth rate highlighted in the Ontario Long Term Energy Plan (LTEP, 2017).

$$B_t^{Fin} = \sum_{t=t_0}^{T=t_{20}} \left(E_t^p * P_t^p\right) + LD_t^{PHS} \qquad \textbf{[Case I}, 5]$$

$$B_t^{Fin} = \sum_{t=t_0}^{T=t_{40}} \left(E_t^p * P_t^p\right) + LD_t^{PHS} \qquad \textbf{[Case II}, 5]$$

The financial costs are: (i) initial capital investment, (ii) cost of operation and maintenance, (iii) cost of off-peak energy needs to be purchased for pumping, (iv) taxes (only income tax is considered[9]), and (v) debt service (interest and principal repayment). The purchase price of electricity used for pumping is set at 60% of the off-peak price, as reported in Hasan (2019).

$$C_t^{Fin} = \sum_{t=t_0}^{T=t_{20}} \left(E_t^{off} * P_t^{off}\right) + CAPEX_t^{PHS} + OPEX_t^{PHS} + T_t^{inc} + DS_t^{PHS} \quad \textbf{[Case I}, 6]$$

$$C_t^{Fin} = \sum_{t=t_0}^{T=t_{40}} \left(E_t^{off} * P_t^{off}\right) + CAPEX_t^{PHS} + OPEX_t^{PHS} + T_t^{inc} + DS_t^{PHS} \quad \textbf{[Case II}, 6]$$

$$NPV_{t=0}^{Fin} = \sum_{t=t_0}^{T=t_{20}} (1+r)^{-t} \left(B_t^{Fin} - C_t^{Fin}\right) \; ; NPV_{t=0}^{Fin} = \sum_{t=t_0}^{T=t_{40}} (1+r)^{-t} \left(B_t^{Fin} - C_t^{Fin}\right)$$

3.2.3 Domestic consumers' point of view

Integrating the planned PHS into Ontario's supply mix will have an incremental financial impact on domestic consumers. Since the IESO is a revenue-neutral organization, the net effect will be passed on to domestic consumers. The revenues obtained by the PHS owner will add to the cost of electricity consumed in the province. Requiring a new wind facility for the second 20 years following our earlier scenario also imposes capital, operating, and decommissioning costs that are all passed on to the consumer. At the same time, the cost of electricity that consumers must ultimately pay is reduced because of the value of the fuel saved. The savings in the alternative peaking gas plant's capital and operating and decomposing costs are other benefits for consumers.

The incremental financial inflows (B_t^{con}), outflows (C_t^{con}) and net present value ($NPV_{t=0}^{con}$) for domestic consumers can be expressed as follows:

$$B_t^{con} = \sum_{t=t_0}^{T=t_{20}} FS_t^p + CAPEX_t^{ng} + OPEX_t^{ng} + DECOM_t^{ng} \quad \textbf{[Case I}, 7]$$

$$B_t^{con} = \sum_{t=t_0}^{T=t_{40}} FS_t^p + CAPEX_t^{ng} + OPEX_t^{ng} + DECOM_t^{ng} \quad \textbf{[Case II}, 7]$$

$$C_t^{con} = \sum_{t=t_0}^{T=t_{20}} \overbrace{[(E_t^p * P_t^p) - (E_t^{off} * P_t^{off})]}^{\text{Financial revenues of PHS owner}} \quad \textbf{[Case I}, 8]$$

[9] It is not yet clear whether the project will pay taxes other than income taxes (such as water rental charge), as noted in the ERM report (2020).

$$C_t^{con} = \sum_{t=t_0}^{T=t_{40}} \overbrace{[(E_t^p * P_t^p) - (E_t^{off} * P_t^{off})]}^{\text{Financial revenues of PHS owner}} + \sum_{t=t_{21}}^{T=t_{40}} CAPEX_t^{wf} + OPEX_t^{wf} + DECOM_t^{wf} \qquad \textbf{[Case II, 8]}$$

$$NPV_{t=0}^{con} = \sum_{t=t_0}^{T=t_{20}} (1+r)^{-t} (B_t^{con} - C_t^{con}) \; ; \; NPV_{t=0}^{con} = \sum_{t=t_0}^{T=t_{40}} (1+r)^{-t} (B_t^{con} - C_t^{con})$$

3.2.4 Governments' point of view

Taxes and other externalities generated by the project represent the difference between the economic resource flows and the financial cash flows. Three levels of government are considered in this study, namely the federal government (FG), the Ontario government (OG), and the Alberta government (AG). The objective is to quantify the fiscal impacts of the planned PHS investment on each of these organizations.

The total receipts accruing to the federal government are only through income taxes. However, as Bahramian et al. (2021b) discussed, income taxes are shared between the federal and Ontario governments. The Ontario government receives 44.23% of total corporate income taxes, while the rest (55.77%) transfers to the federal government. No incremental expenditures are assumed for the federal and Ontario governments. The project is in the approval stage and may receive some federal or provincial subsidies. Thus, the total government benefits considered here relate to the income tax revenues shared between the two governments.

$$B_t^{FG} = \sum_{t=t_0}^{T=t_{20}} 55.77\% * T_t^{inc} \; ; \; B_t^{OG} = \sum_{t=t_0}^{T=t_{20}} 44.23\% * T_t^{inc} \qquad \textbf{[Case I, 9]}$$
$$B_t^{FG} = \sum_{t=t_0}^{T=t_{40}} 55.77\% * T_t^{inc} \; ; \; B_t^{OG} = \sum_{t=t_0}^{T=t_{40}} 44.23\% * T_t^{inc} \qquad \textbf{[Case II, 9]}$$

$$PV_{t=0}^{FG} = \sum_{t=t_0}^{T=t_{20}} (1+r)^{-t} \left(B_t^{FG}\right) ; PV_{t=0}^{OG} = \sum_{t=t_0}^{T=t_{20}} (1+r)^{-t} \left(B_t^{OG}\right)$$
$$PV_{t=0}^{FG} = \sum_{t=t_0}^{T=t_{40}} (1+r)^{-t} \left(B_t^{FG}\right) ; PV_{t=0}^{OG} = \sum_{t=t_0}^{T=t_{40}} (1+r)^{-t} \left(B_t^{OG}\right)$$

For the Alberta government, the incremental tax losses (C_t^{AG}) are caused by the reduced gas sales to Ontario. Using the rate of the royalty paid to the Alberta government on gas sales (R_r) of

8% (Alberta Ministry of Energy, 2019), the impact on the present value of royalty revenues obtained by the Alberta government ($PV_{t=0}^{AG}$) can be defined as:

$$C_t^{AG} = \sum_{t=t_0}^{T=t_{20}} R_r * FS_t^p;\ PV_{t=0}^{AG} = \sum_{t=t_0}^{T=20} (1+r)^{-t} \left(-C_t^{AG}\right) \qquad \text{[Case I, 10]}$$

$$C_t^{AG} = \sum_{t=t_0}^{T=t_{40}} R_r * FS_t^p;\ PV_{t=0}^{AG} = \sum_{t=t_0}^{T=40} (1+r)^{-t} \left(-C_t^{AG}\right) \qquad \text{[Case II, 10]}$$

3.2.5 Environmental impacts

A key policy objective of integrating PHS into the Ontario electricity grid is to reduce CO_2 emissions by displacing peaking thermal-powered generation plants during peak periods.[10] Here this substitution provides global environmental benefits. However, these benefits depend mainly on the type of generation being displaced, its carbon emission rates, and the selected values for the social cost of CO_2 abatement. The updated carbon pricing report (hereafter "Canadian standard") of the Government of Canada (2021)[11] recommends that a value of the social cost of carbon of USD 112.06/tonne be used for 2028 (the commencement year of the PHS operation), USD 124.07/tonne for 2029, and USD 136.07/tonne for 2030 onward. In contrast, the value recommended by the US government (hereafter "USA standard") Interagency Working Group report (2021) varies between USD 56 and USD 85/tonne.

The significant disparity between these two recommended values indicates that these "prices" are not set to be reflective of the monetized values of the utility that residents of either country obtain from CO_2 abatements. Rather, these are shadow prices set by policymakers in the respective governments for use in the cost-benefit analysis of interventions that will have an impact on CO_2 emissions. These shadow prices reflect the maximum willingness to pay (MWP) by

[10] The main environmental cost in the combustion of natural gas is the production of carbon dioxide (Bahramian et al., 2021b). The estimated impacts on nitrogen oxides (NOx), sulfur dioxide (SO_2), and particulates are very small and are not included as a cost of generation by natural gas.
[11] The originally reported carbon prices are all in the Canadian dollar and are converted to the US dollar using the average exchange rate (USD/CAD) of 1.25.

governments to spend economic resources on interventions that will reduce CO_2 emissions. Interventions that will incur economic resource costs that are less than these values are to be preferred. At the same time, no investment project in Canada or the USA should be undertaken where the economic cost of reducing CO_2 emissions from a global perspective exceeds these specified values.

In the analysis that follows, the assumption is made that no environmental costs are imposed by the PHS facility or wind farms from such environmental items as reduced house prices due to reduced quality of views and bird-killing. Hence, the maximum incremental impact on positive externalities $\left(B_t^{envir}\right)$ becomes equal to the $PV_{t=0}^{envir}$ for the environment, and it can be presented as:

$$PV_{t=0}^{envir} = B_t^{envir} = \sum_{t=t_0}^{T=t_{20}} (1 + r)^{-t} [(E_t^p * CC^g * SCC_t)] \qquad \textbf{[Case I, 11]}$$

$$PV_{t=0}^{envir} = B_t^{envir} = \sum_{t=t_0}^{T=t_{40}} (1 + r)^{-t} [(E_t^p * CC^g * SCC_t)] \qquad \textbf{[Case II, 11]}$$

4. EMPIRICAL FINDINGS

This section discusses the empirical results following the methodology outlined in section 3. First, using the LCOE standard, for both cases, the PHS integrated system's efficiency and cost-effectiveness are compared with the costs of an alternative set of gas peaking plants that would supply the peak demand periods' needs and help stabilize the system. These results are followed by those of the economic and stakeholder appraisals.

4.1 Levelized cost analysis

As shown in Table 1, under Case I, the SBG-PHS integrated system with the LCOE of 0.102/kWh is not the least cost-effective option (from the Canadian economy's point of view) for meeting the peak period demand compared to the alternative gas peaking power plant with the LCOE of 0.063/kWh. However, when the social cost of carbon (SCC) of the Canadian standard is added to our LCOE calculation, the SBG-PHS integrated system is a promising option from the world perspective, with the LCOE of 10.2 cents/kWh as compared to 11.8 cents/kWh for the natural gas peaking plant.

Table 1: Levelized Cost of Energy (USD/kWh, 2021 values)

Plant	Capital Cost	Operating Cost	Social Cost of CO_2	LCOE
Case I – 20-year profile				
SBG-PHS integrated system	0.097	0.005	--	0.102
Natural gas peak plant*	0.027	0.036	--	0.063
Natural gas peak plant with SCC (Canadian standard)	0.027	0.036	0.055	0.118
Natural gas peak plant with SCC (USA standard)	0.027	0.036	0.027	0.090
Case II – 40-year profile				
SBG-wind-PHS integrated system	0.090	0.007	--	0.097
Natural gas peak plant*	0.027	0.036	--	0.063
Natural gas peak plant with SCC (Canadian standard)	0.027	0.036	0.052	0.115
Natural gas peak plant with SCC (USA standard)	0.027	0.036	0.026	0.089

Note: SBG, surplus baseload generation. *, signifies the natural gas peaking (single-cycle plant) with a heat rate of 9,800 British thermal units (BTU) per kWh (Lazard, 2020).

Under Case I, the CAPEX cost of the SBG-PHS system is estimated at 9.7 cents per kWh. This compares with 2.7 cents per kWh for the CAPEX of the alternative gas power plants. Hence, the capital requirement of the integrated system (SBG-PHS) is much more expensive (more capital intensive) than the alternative single-cycle plants (gas peaking power plants).

In general, the SBG-PHS integrated system is a cost-effective option using the Canadian shadow prices for the SCC. However, if this same project were located in the USA, using the US shadow SCC prices, the peaking gas plant would be a more cost-effective option (LCOE of 9.0

cents/kWh) than the SBG-PHS integrated system (LCOE of 10.2 cents/kWh). Here it should be noted that although the SCC plays a significant role for policymakers, this element should be considered from the world perspective, not Canada alone. Very little of the estimated value of the SCC abated by the project would be a direct benefit to the economic welfare of Canadian residents.

Moving to Case II, the same set of results is observed. The SBG-wind-PHS integrated system is a cost-effective option when the cost of natural gas peaking plant is accompanied by the SCC using the proposed Canadian standards; however, with the same setting when the SCC is calculated based on the USA carbon pricing scheme in the 40-year profile, the SBG-wind-PHS integrated system is not the lowest economic cost solution. This is the result even when surplus off-peak energy is available for pumping at a zero marginal cost for the first 20 years of the PHS plant's life. This is followed by a second 20-year period during which additional wind farms are constructed to provide electricity to offset the generation required for pumping.

Without including the SCC, the combined wind and PHS cost 9.7 cents to produce a kWh of peak energy, while the gas turbine costs 6.3 cents per kWh under similar conditions. When the SCC is accounted for, using the Canadian shadow prices for SCC, the peaking gas turbine costs 11.5 cents per kWh; hence, the PHS integrated system would be justified. Alternatively, if the US shadow prices for the SCC are used, the thermal option (with LCOE of 8.9 cents per kWh) for meeting the peak load demand is still more efficient and cost-effective than the SBG-wind-PHS combined system. The wind and PHS combination would indeed emit less carbon into the atmosphere. However, even considering the SCC savings using the USA standard, the potential global net benefits will still not be enough to neutralize the additional capital cost required to construct the PHS as compared to the gas turbine.

4.2 Economic and stakeholder analyses

Having discussed and compared the feasibility of both the PHS integrated system and gas peaking plants through the LCOE metric lens, the net impact of the planned PHS facility is now measured and distributed to find the feasibility of the project from each point of view. The results are reported for both cases following the scenario postulated in section 3. While evaluating the viability of the planned PHS project, a single real rate of discount of 8% (Treasury Board of Canada Secretariat, 2007) is used for the cost of capital to all parties throughout the project's life. For the economic analysis, the economic conversion factor for gas is calculated to be 0.92 (Bahramian et al., 2021b).

As illustrated in Table 2, under Case I, the key potential benefit for the Canadian economy is the value of gas and capital costs saved from reduced generation by gas turbines. Unfortunately, these are insufficient to compensate for the possible costs that will be imposed on the economy by the Ontario-planned PHS project. In total, the economic benefit (Table 2, row 2) obtained from the SBG-PHS facility is about 61% ($\frac{1{,}213.60}{1{,}986.53} = 0.61$) of the PV of its total economic costs (Table 2, row 1). The benefit-cost ratio increases to 64% ($\frac{1{,}474.17}{2{,}292.86} = 0.64$) when the economic benefits and costs of the SBG-wind-PHS system (Table 2, rows 12 and 13) are examined under Case II for the 40-year profile.

In both cases, the economic analysis here demonstrates that the planned PHS project's economic NPVs (Table 2, rows 3 and 14) are negative from a Canada-only perspective. In total, under Case I and II, it yields net losses of about USD 773 million and USD 819 million, respectively, for the Canadian economy. Thus, the scheduled PHS project will drain Canada's economic resources. Given that the net economic loss is greater in Case II than in Case I, it would be more beneficial to Ontario's residents if the PHS were abandoned after 20 years than to continue its operation as a complementary technology to additional investments in wind-powered generation.

Table 2: Estimated PVs of Stakeholder Impacts in USD million as of 2022 adjusted at 2021 price level

#	Case I – 20-year profile	Total
	Economic analysis	
1	PV of economic costs	1,986.53
2	PV of economic benefits	1,213.60
3	Net Canadian economy gain/loss	−772.92
	Stakeholder analysis	
	Financial analysis	
4	Financial NPV	6.43
	Domestic consumer	
5	Net consumer gain/loss	−705.98
	Government	
6	PV of federal government fiscal impacts	196.55
7	PV of Ontario government gain/loss	155.89
8	PV of Alberta provincial government	−50.16
9	Total governments gain/loss	302.28
	Environmental externality	
10	PV of global environmental externality (Canadian standard)	1,070.48
11	PV of global environmental externality (USA standard)	521.17
	Case II – 40-year profile	
	Economic analysis	
12	PV of economic costs	2,292.86
13	PV of economic benefits	1,474.17
14	Net Canadian economy gain/loss	−818.70
	Stakeholder analysis	
	Financial analysis	
15	Financial NPV	54.37
	Domestic consumer	
16	Net consumer gain/loss	−776.82
	Government	
17	PV of federal government fiscal impacts	189.79
18	PV of Ontario government gain/loss	150.53
19	PV of Alberta provincial government	−60.92
20	Total governments gain/loss	279.40
	Environmental externality	
21	PV of global environmental externality (Canadian standard)	1,229.44
22	PV of global environmental externality (USA standard)	619.02

Note: PVs are evaluated at a wind capacity factor defined as 32%. This ratio is derived based on the average capacity factor in Ontario from 2009–2020, tabulated from the IESO database.

Introducing the planned PHS in Ontario is intended to provide firm electricity on a daily cycle during peak hours. However, in both cases, the significant benefits (the values of fuel-saving and the capital and operating savings of gas peaking power plants) are not large enough to cover the costs of the integrated system. This paper assumes that the SBG used to pump water up to the PHS over the next 20 years has a zero marginal cost. If the marginal cost for some of this surplus electricity is positive, the cost of the integration of the planned PHS in Ontario will be higher.

As previously highlighted, the capital cost of the planned PHS for Ontario is estimated at constant 2021 prices to be USD 2,433/kW, which is close to the upper level of the range USD 617–2,465/kW provided by IRENA (2020). It is crucial to see how the economic NPVs in both cases would change if the PHS facility were built at a site requiring lower capital costs. Table 3 reports on sensitivity analysis for a range of capital costs per kW to determine the level of capital costs of the PHS that would cause this facility to have a positive economic NPV. As evident, the PHS integrated system could be economically feasible in Case I if the planned PHS capital costs were 40% lower (USD 1,460/kW). In Case II, if the capital costs were 50% less (USD 1,216/kW), the PHS integrated system would be feasible over a 40-year profile.

Table 3: Sensitivity Analysis for Capital Cost of PHS

	PHS Capital Cost (USD/kW, Real Value)	Economic NPV	
		Case I	**Case II**
Base Case	**2,433**	**−772.92**	**−818.70**
−10%	2,190	−574.27	−617.07
−20%	1,946	−375.62	−415.45
−30%	1,703	−176.96	−213.83
−40%	1,460	21.69	−12.21
−50%	1,216	220.34	189.41

Note: NPVs are USD million as of 2022 adjusted at 2021price level.

Using the selling and purchasing prices discussed in section 3, under Case I and II, the financial NPVs of the planned PHS facility (Table 2, rows 4 and 15) are found to be slightly positive (USD 6.43 million and USD 54.37 million, with financial internal rates of return of about 8.06% and 8.34%, respectively). This return is not excessive for corporations in Canada. This is not surprising as the financial revenues of the PHS owner will be secured using a power purchase agreement (PPA) with the IESO of the Province of Ontario.

The negative net economic NPVs of the PHS integrated plant from a Canada-only perspective in both cases are reflected in the magnitude of the loss borne by the various stakeholders of the electricity system, primarily the electricity consumers and taxpayers of Ontario. Here the savings due to the integration of the planned PHS plant (mainly fuel-saving) would not be enough to cover the costs of the integrated facility. In both cases, the PHS and wind farm owners would receive a normal rate of return of about 8%. The net result is that the PHS integrated system will impose a total PV of losses of USD 705.98 million and USD 776.82 million on domestic consumers of Ontario (Table 2, rows 5 and 16).

The PVs accruing to governments from the PHS plant in total are positive in both cases (Table 2, rows 9 and 20). The PHS facility will provide a total PV of USD 302.28 million in Case I and USD 279.40 million in Case II to the governments in Canada.[12] In Case I, the PV of taxes of USD 196.55 million and USD 155.89 million (Table 2, rows 6 and 7) accrue to the federal and Ontario governments, respectively, from income tax payments. For Case II, the federal and Ontario governments accrue the PVs of USD 189.79 million and USD 150.53 million (Table 2, rows 17 and 18), respectively.

More than 50% of the natural gas consumed in Ontario is sourced from Alberta (Bahramian et al., 2021b). One effect of the electricity generated by the planned PHS facility during peak hours is to reduce the demand in Ontario for natural gas. This will lead to a PV of losses of natural gas royalties to the government of Alberta of USD 50.16 million and USD 60.92 million for Cases I and II, respectively (Table 2, rows 9 and 19).

[12] The income taxes are calculated based on the assumption of the debt ratio of 60%.

Under the Canadian schedule for the maximum social costs of CO_2 emissions, the PV of global environmental benefits from CO_2 reductions obtained from the gas generation displacement by the PHS integrated system in Ontario is USD 1,070.48 million in Case I and USD 1,229.44 million in Case II (Table 2, rows 10 and 21). A lower set of environmental costs avoided for both cases are measured using the USA carbon pricing standard. The global environmental benefits are estimated at USD 521.17 million for Case I and USD 619.02 million for Case II.

With estimated global environmental benefits, one can now assess the economic impact of the PHS integrated system from the world perspective. Jenkins et al. (2019) discuss that if the stakeholders have the same discount rate, the global economic NPV ($\mathrm{NPV}^{\mathrm{global}}$) of the project will be equal to the Canadian economic NPV plus the PV of the environmental externality. In this regard, using the Canadian carbon pricing standard, the $\mathrm{NPV}^{\mathrm{global}}$ of the PHS integrated system in both cases will be a positive USD 297.56 million and USD 410.74 million, respectively. This shows that the PHS integrated system would be marginally positive from a global perspective if the world placed as high a willingness to pay to reduce CO_2 as has been suggested by the Canadian government. However, when the USA carbon pricing range is considered, the $\mathrm{NPV}^{\mathrm{global}}$ is a negative USD 251.76 million in Case I and a negative USD 199.68 million in Case II. In either case, the electricity consumers in Ontario would be paying a very high price of either USD 705.98 million or USD 776.82 million, respectively, for the uncertain values of the social benefits that are accruing to the rest of the world through its mitigation of CO_2 emissions in this manner.

4.3 An alternative option

When considering this PHS from the world economic perspective, a third option becomes available. There is a need to consider the economic costs and benefits if Ontario were to simply export its surplus baseload power to the USA free of charge. At present, the main partners in Ontario's electricity grid might have a limitation on their ability to use Ontario's surplus baseload electricity. However, given the size of the US market and its degree of integration, it might be able to accommodate such an offer by Ontario if it were for a 20-year period.

As natural gas is the largest source of fuel for electricity generation in the USA (EIA, 2019), exporting more electricity from Ontario to the USA free of charge would allow the US grid authorities to substitute these increased exports of baseload electricity from Ontario for their baseload natural gas electricity generation. This option has little or no incremental economic cost for Canada. Assuming the same efficiency rating of the natural gas power plants in the USA and Canada, this option could provide approximately USD 577 million of economic benefits in fuel-saving to the US utilities. In addition, it would reduce CO_2 emissions in the USA, valued at USD 521.12 million, for a total NPV^{global} of about USD 1,098 million. Compared with the results for Case I and Case II, wherefrom a global perspective the NPV^{global} economic is either negative or modestly positive; this third option is vastly superior.

Considering the stakeholder impacts, the first two options, where a PHS absorbs the surplus baseload electricity with a net loss to Canadian consumers of approximately USD 706 million, the third option of giving the electricity-free to the USA through its grid interconnections would have no cost to Canadian consumers, a gain to US consumers of USD 577 million due to reduced gas costs, and a global benefit of reduced CO_2 of between USD 1,070.48 million (using Canadian government shadow prices for CO_2 emissions) and USD 521.17 million (using US government shadow prices for CO_2 emissions). Furthermore, if Ontario made this gift of electrical energy to the US border states, it might be able to obtain more favorable consideration in negotiations on other joint economic matters.

5. CONCLUSIONS

Through the integrated investment appraisal and the LCOE metric, the findings of this study show that introducing a new PHS facility to absorb the projected baseload electricity surpluses to generate electricity during peak hours is far from being the least-cost economic strategy. Integration of additional wind power and PHS facility is also found not to be a cost-effective and economically viable solution in Canada.

The net savings in fuel due to the deployment of the wind farms and the introduction of the planned PHS facility yields a very poor economic return on the investments. The negative economic NPV is passed on to Ontario consumers through higher than necessary electricity prices. The results indicate that if the US carbon emissions pricing standard were applied, the investment in PHS to absorb the surplus baseload power would still have a negative economic NPV from a world perspective.

It would be better socially from the world perspective if the surplus baseload electricity from Ontario was given away to the USA free of charge. It could then be used to reduce generation by natural gas plants in the USA, which is a saving in the world's economic resources. In addition, it would reduce CO_2 emissions in the USA, and hence the world, without any incremental cost to Canada.

This study illustrates the importance of planning the expansion of an electricity system in a least-cost manner to avoid the vast quantities of SBG. It may initially appear that building a PHS plant is a solution, but it would be an exercise in throwing good resources after bad if it were implemented.

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