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Hydrogen Economy Transition in Ontario-Canada Considering the Electricity Grid Constraints

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Abstract
This paper investigates the feasibility of electrolytic hydrogen production for the transport sector during off-peak periods in Ontario. This analysis is based on the existing electricity system infrastructure and its planned future development up to 2025. First, a simplified but realistic zonal based model for Ontario's electricity transmission network is developed. Then, based on Ontario's Integrated Power System Plan (IPSP), a zonal pattern of generation capacity procurement in Ontario from 2008 to 2025 is proposed, specifying the total effective generation capacity in each zone that contributes to base-load energy. Finally, an optimization model is developed to find the optimal size of hydrogen production plants to be developed in different zones, as well as optimal hydrogen transportation routes to achieve a feasible hydrogen economy penetration in Ontario up to 2025. The proposed model is shown to be an effective planning tool for electrolysis based hydrogen economy studies. The results of the present study demonstrate that the present and projected electricity grid in Ontario can be optimally exploited for hydrogen production, achieving 1.2 % to 2.8 % levels of hydrogen economy penetration by 2025 without any additional grid or power generation investments beyond those currently planned.

Keywords: Hydrogen economy, electricity grid, optimal planning, transportation, Ontario.

1. Glossary of terms

CDM: Conservation and Demand Management
CHP: Combined Heat and Power
FCV: Fuel-Cell Vehicle
HHV: Higher Heating Value
HOEP: Hourly Ontario Energy Price
HPP: Hydrogen Production Plant
HVDC: High Voltage Direct Current
IESO: Independent Electricity System Operator
IPSP: Integrated Power System Plan
IRR: Internal Rate of Return
LMP: Locational Marginal Price
MILP: Mixed-Integer Linear Programming
NLP: Nonlinear Programming
NPV: Net Present Value
NUG: Non-Utility Generation
OPA: Ontario Power Authority
PI: Profitability Index
SIL: Surge Impedance Loading
SMR: Steam Methane Reforming

2. Introduction

Currently, energy utilities are presented with the challenges of increased energy demand and the need to immediately address environmental concerns such as climate change. Due to population and economic growth, the global demand for energy is expected to increase by 50% over the next 25 years [1,2]. This significant demand increase along with the dwindling supply of fossil fuels has raised concerns over the security of the energy supply. In view of the increased energy demand and environmental pollution, different approaches such as distributed generation and demand-side management have been proposed and are widely being put into practice. However, the optimal utilization of the existing energy infrastructures is an issue that also needs to be properly addressed to deal with the major challenges that energy utilities are facing; this is the main aim of the present paper.

In the past, energy infrastructure projects have typically been planned and operated independently, but the present trend is to move towards an *integrated view*, because of the common technical and economic interactions between different types of energy infrastructure. Of specific interest is in the integration of energy for the electrical power demand with the energy demand for transportation fuel. For effective and coordinated planning and operation, each energy system needs to be investigated in the context of an integrated system [3-9]. For example, congestion on a particular electrical transmission path can be relieved by shifting part of the energy flow to another energy network, such as one that uses hydrogen as an energy vector [8], as discussed in this paper. However, complex problems arise in this integrated approach, given the size of the problem and the multiple economic and technical interactions between various sub-systems [9]. Accordingly, appropriate models and tools need to be developed to investigate all these interactions, considering the different types of energy infrastructures and energy vectors involved in such integrated systems.

The transport sector is one of the largest and fastest growing contributors to both energy demand, urban air pollution and greenhouse gases; for example, in Canada, the transport sector represents almost 35% of the total energy demand and is the second highest source of greenhouse gas emissions [10,11]. In view of these issues and the challenges associated with the supply of oil, the issue of alternative fuels, in particular hydrogen, for meeting the future energy demand of the transport sector has gained much attention. Thus, the ultimate goal is to find a zero emission transportation fuel such as hydrogen that can be derived from a wide range of primary energy resources.
Hydrogen, as an energy carrier, can link or interface multiple energy resources for multiple end-uses; this has led to the development of the *hydrogen economy* concept [12-16], which originated in the early 1970s. If non-fossil energy sources for hydrogen production are utilized, hydrogen as a new energy carrier in the framework of integrated energy systems will significantly help relieve many environmental concerns. For example, no NO_x, SO_x, and CO_2 emissions will be generated by hydrogen-powered vehicles in the urban airshed [17]; also, decentralized generation of electricity and heat using stationary fuel cells would yield no smog precursor emissions.

Hydrogen can also be considered as a new alternative for electricity storage. For electrically powered, zero emission vehicles, batteries are limited in range, do not allow for rapid refuelling, and are costly; onboard use of hydrogen allows for zero emission vehicles with extended range and rapid refuelling. Furthermore, hydrogen production through the electrolysis process has approximately 80 % efficiency, which means that most of the electrical energy can be stored and distributed as hydrogen [12,18]. Also, the economics of production, storage, and the utilization of electrolysis based hydrogen become quite relevant in the context of competitive electricity markets, given the significant price differences between peak and low price periods [9,19]; this economic argument becomes more compelling if environmental pollution costs are considered [20,21]. In addition, since traditional generation plants are most efficient when operating at rated load levels, and considering congestion problems in the electricity transmission system during the normal operation of a power grid, the use of hydrogen as an energy carrier to increase the efficiency and reliability of the grid is certainly attractive [8]. Furthermore, penetration of FCVs into Ontario's transport sector introduces an energy storage capacity for Ontario's grid and this in turn facilitates the integration of intermittent energy resources such as wind and solar.

At the present state of technological development, there are still a variety of challenges regarding the production, distribution, storage, and use of hydrogen (e.g., [22-25]). Therefore it is necessary to develop appropriate tools and models to study a transition to a hydrogen economy to better understand the specific advantages and disadvantages, with the consideration of costs.

Planning the transition to a hydrogen economy has been studied in various locations and reported in the literature [26-36]. Each of these plans considers particular aspects of this issue, varying considerably from place to place due to different local constraints and energy policies. This paper discusses a different aspect of this transition in Ontario, Canada, based mainly on electrolytic hydrogen production. Motivated by the notion of efficient utilization of the existing infrastructures and the concept of integrated energy systems, an optimization planning model that takes into account both electricity and hydrogen networks as one integrated system is presented and discussed. Considering the future development of both generation and transmission capacities in Ontario between 2008 and 2025, the paper aims at finding the maximum hydrogen economy penetration within this constrained planning framework. Specifically, this paper intends to determine the percentage of cars on the road that could be fuelled by hydrogen in Ontario, based on electrolytic hydrogen production during off-peak electricity price time intervals. The developed model determines the optimal size of HPPs to be installed in different zones of Ontario and the required optimal hydrogen transportation routes, in the framework of the existing electricity network and the electricity networked planned future development according to Ontario's IPSP [37]. The main goal of the present research is to determine how the Ontario's electricity network can be optimally exploited during the base-load periods for hydrogen production without jeopardizing the reliability of the system or developing new and separate infrastructure to cover the electricity requirement of HPPs. This work considers the future development of the electricity network to provide a realistic forecast for hydrogen potential; thus, it provides a realistic projection for FCV market penetration in the near term without having to provide extraordinary increases to the electricity network itself.

The rest of the paper is structured as follows: In Section 3, appropriate models for the proposed Ontario-centered studies are presented, including a simplified but realistic electricity transmission network model, the planned power generation, and the hydrogen transportation requirements during the planning years; the required electricity and hydrogen system data are also discussed and justified in this section. The proposed optimization model and analysis techniques are described in Section 4.

The results obtained from the solution of the proposed models and data are presented and discussed in Section 5. Finally, Section 6 highlights the main contributions and conclusions of the presented studies.

3. Ontario electricity and hydrogen system models

3.1. Electricity network model

The Ontario's IESO represents the Ontario network with 10 zones [38]. Figure 1 provides the geographic depiction of these zones, major transmission interfaces, and transmission interconnection points with other jurisdictions. This 10-zone representation is used here to develop the 10-bus simplified model of Ontario's network to represent the main grid load and generation centers and transmission corridors.

Fig. 1 – Main Ontario's gird zones and simplified model of Ontario's grid.

The simplified electrical system used here is mostly a 500 kV network, with a 230 kV interconnection between NE and NW. Hence, the parameters used to model this network are based on typical values of 500 and 230 kV networks, considering the approximate distances between zones and transmission capacities, as per general information provided by the IESO [38] and line loading-limits in per unit of SIL [39]. Based on the existing and planned projects provided by OPA [37,40], the transmission capacity enhancements presented in Table 1 are assumed for the simplified model used in this study.

Table 1 – Estimated transmission corridor enhancements for simplified grid model.

Year	Corridor	Current MW	Planned MW
2012	Bruce-SW	2560	4560
2012	SW-Toronto	3212	5212
2013	NE-NW	350	550
2015	Bruce-West	1940	2440
2017	Toronto-Essa	2000	2500
2017	Essa-NE	1900	2400

3.2. Electricity generation model

Based on the Ontario IPSP and a variety of information provided by the OPA and the IESO [37,40-48], a zonal pattern of generation capacity between 2008 and 2025 contributing to base-load energy in Ontario was developed. The proposed model specifies the total effective generation capacity which is available in each zone to supply for base-load. The mix of base-load generation resources in Ontario which is considered in this study include nuclear, wind, hydro (only those units with limited dispatch capability and small scale units less than 10 MW), CHP, CDM, and coal. It is important to mention that the contribution of gas-fired generation to base-load energy has been disregarded in this study, based on the Ontario government's 2006 Supply Mix Directive indicating that natural gas should only be used at peak-load times and in high-efficiency and high-value applications [37,42]. Furthermore, there are some CHP facilities in Ontario, which are under long-term NUG power purchase agreements; hence, to be conservative, these CHP-NUG facilities have not been considered in the mix of base-load capacity, based on the fact that their contracts will expire over the 2012-2018 period and because there are uncertainties regarding their operation during base-load periods [44]. A brief explanation regarding each of the base-load generation resources in Ontario follows.

3.2.1. Nuclear

The present installed nuclear capacity in Ontario, located in the Bruce and Toronto zones, is 14000 MW, with 11365 MW in operation, 1500 MW under refurbishment (Bruce A, Units 1 & 2), 1057 MW already refurbished (Pickering A, Units 1 & 4), and about 1100 MW on long-term lay up (Pickering A, Units 2 & 3). Also, the present operating capacity includes 4720 MW in the Bruce zone (Bruce A: 1540 MW, Bruce B: 3180 MW) and 6645 MW in Toronto zone (Pickering A: 1057 MW, Pickering B: 2064 MW, and Darlington: 3524 MW) [43,44]. According to the 20-year energy plan set by the Ontario government, nuclear energy capacity should be maintained for base load operation up to its current level of 14000 MW [37,42]; this will require that existing nuclear plants be refurbished and/or new plants be built to maintain this capacity. For the new projected nuclear plant development, the following scenarios have been assumed:

- Scenario 1: 1762 MW new nuclear power will be available in the Toronto zone in 2018. This assumed capacity is equal to two Darlington units.
- Scenario 2: 1500 MW new nuclear power will be available in the Bruce zone in 2018. This assumed capacity is equal to two Bruce A units.

3.2.2. Wind

The share of wind power to meet the renewable target in 2025 (15700 MW) is 4685 MW. This includes 395 MW of existing wind power in 2007, 1251 MW of committed wind power that will be in service by 2010, and 3039 MW of small and large wind projects which are planned to be in service between 2011-2025 [45-48]. An average wind power capacity factor of 30% for base-load energy service is assumed in this study [45,49,50].

3.2.3. Hydro

Currently, there are 7788 MW of hydroelectric capacity in Ontario, of which 3161 MW is provided by run-of-the-river facilities located in the Niagara and East zones that contribute to base-load energy, each with the total capacity of 2116 and 1045 MW, respectively [43-45]. The share of hydroelectric capacity in the target value of renewables in 2025 (15700 MW) is almost 10700 MW, meaning that almost 2912 MW of hydropower is planned to be developed between 2008-2025 [40,46,48]. All the existing run-of-the-river hydroelectric plants (in Niagara and East zones) plus the 25 MW run-of-the-river unit which is planned to be in service by 2012 in NE are considered here to contribute to base load energy with a 78% capacity factor. Existing and planned small-scale hydro units (10 MW or less in size) that are not run-of-the-river facilities are also assumed to contribute to base load energy, but with an average capacity factor of 50% [44,45,47].

3.2.4. CHP

There are currently 7 new CHP projects with a total capacity of 414 MW under development across Ontario [51]. The projects, which have been planned to be in service by the end of 2008, include 12 MW in SW, 11.5 MW in West, and 7.3 MW in Toronto. Also, 2 projects including 84 MW in West and 63 MW in NE, as well as a 236 MW plant in Niagara will be in service by 2009 and 2010, respectively. Since the OPA has been directed by the Ontario Ministry of Energy to procure 1000 MW CHP generation [42,45,51], there are 586 MW of CHP plants expected to be developed in the future. The OPA has targeted 2013 as the completion date for the planned CHP resources in Ontario [44]. In this study, the planned CHP capacity (586 MW) is equally split between the existing CHP zones, i.e., all the zones except for Bruce, Essa and NW.

3.2.5. CDM

CDM programs are basically energy saving programs and incentives such as building retrofitting or the use of smart meters to implement time-of-use electricity pricing to encourage customers to manage their electricity consumption. These programs are expected to result in a reduction on demand, and in [37] are considered as a supply resource, giving them the same importance and priority as generation resources such as nuclear, renewables or gas-fired plants. According to the OPA, CDM programs have the potential to offset the expected growth in demand over the next 15 years; therefore, CDM programs are considered here, and as per [37] are assumed to be independent of demand growth.

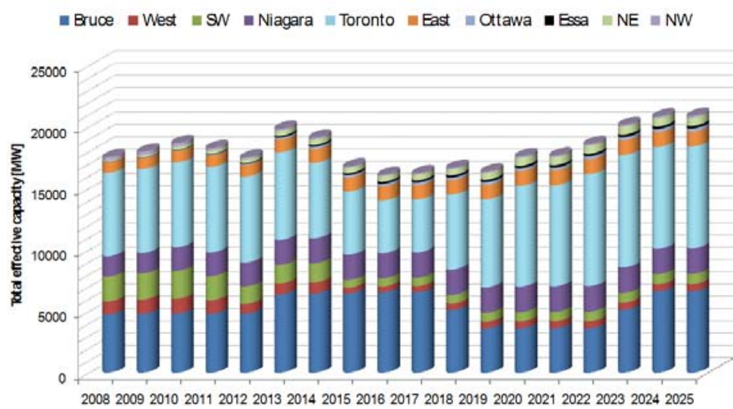
Based on the Ontario IPSP, the target values for peak load reduction are 1350 MW by 2010 and another 3600 MW by 2025 [37]; however, the effective capacity released by CDM during base-load time intervals is relatively less than these target values. Thus, both committed (2008-2010) and planned (2010-2025) target values for base-load CDM capacity released are, as per [44], 550 MW and 2587 MW by 2010 and 2025, respectively. In this study, the share of each zone from the released capacity target values is considered to be proportional to the ratio of its base-load demand with respect to the total base-load demand. Furthermore, it is assumed that only 75% of the planned conservation is to be achieved in practice.

3.2.6. Coal

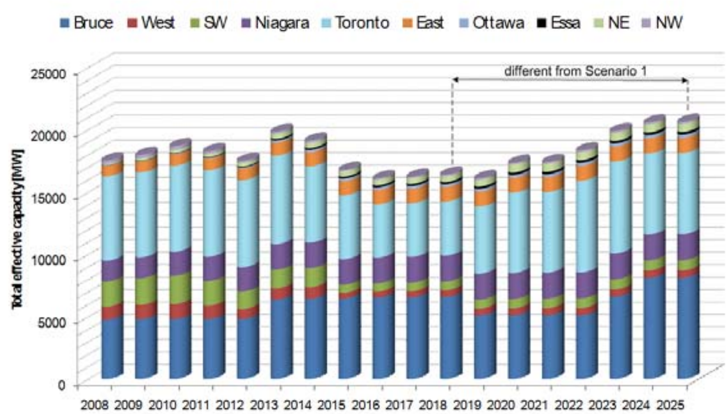
Currently there are 4 coal plants operating in Ontario with a total capacity of 6285 MW [43]. These plants, which are located in West (1948 MW), SW (3820 MW), and NW (517 MW), are planned to be phased out by the end of 2014 [37,40,44,52]. Coal plants in Ontario are neither "base-load" nor "peaking" plants and are typically considered in the category of "intermediate-load" plants [43]. In this study, the contribution of coal plants to base-load energy is considered with a capacity factor of 50%, which is a typical value in the base-load system studies performed by the OPA [44,45]. It was found that given the maximum contribution of coal plants to the total base-load energy in Ontario, i.e., 17% in 2008-2010, 14% in 2011, 9% in 2012-2014, and none after 2014, their contributions to CO_2 emissions is not really significant during the study period, thus helping to meet the requirements of a true hydrogen economy.

3.2.7. Total effective generation capacity in Ontario

Considering the previously discussed base-load resources in Ontario, total effective generation capacity which is available in each zone during 2008-2025 is calculated. The corresponding results for both scenarios are illustrated in Fig. 2. These figures highlight the dominant contribution of both the Toronto and Bruce zones in supplying the base-load requirements of Ontario. Furthermore, observe that the total effective capacities under both scenarios are at their lowest levels during 2016-2021; this is mainly due to coal plants retirements and both Bruce B and Pickering B refurbishments.



a. Scenario 1 – New nuclear reactors in Toronto Zone.



b. Scenario 2 – New nuclear reactors in Bruce Zone.

Fig. 2 - Total effective generation capacity in Ontario contributing to base-load energy.

3.3. Base-load electricity demand model

To find the base-load demand of the different zones of Ontario on the various years of the planning horizon, zonal base-load demand growth rates need to be determined based on the available data, which are the zonal peak demand forecasts from 2007 to 2015 [53], and the average base-load demand in 2007 [54]. The average values of annual peak demand growth rates shown in Table 2 were readily calculated from [53]; it is assumed here that these values are reasonably valid for the whole planning horizon.

Table 2 - Estimated percent of zonal annual peak-demand growth rate in Ontario.

Zone	Bruce	West	SW	Niagara	Toronto	East	Ottawa	Essa	NE	NW
Annual growth rate	0.78	1.14	1.28	0.41	0.77	0.71	1.42	1.17	-0.33	0.10

As per [44,45], the average base and peak load values in Ontario from 2007 to 2025 will increase by 21% and 24%, respectively. On average, these load increases translate into 1.11% and 1.26% of base and peak load annual growth rates respectively for all of Ontario. If the ratio of base-load growth rate λ_i to peak-load growth rate π_i is assumed to be constant for all the zones, then its value can be calculated as follows:

$$\sigma = \frac{\lambda_i}{\pi_i} = \frac{\lambda \sum_i b_i}{\sum_i \pi_i b_i} \tag{1}$$

where λ is the annual base load growth rate of Ontario's total zones and b_i is the base load value in Zone i. Hence, the zonal annual growth rates of base load can be calculated as follows:

$$\lambda_i = \lambda \left(\frac{\pi_i \sum_i b_i}{\sum_i \pi_i b_i} \right) \tag{2}$$

The zonal annual growth rates obtained from (2) along with the Ontario's average base-load demand in 2007 [54] were used to obtain the annual expected base load in different zones of Ontario during the planning years.

Comparing the total effective generation capacity in Ontario for Scenario 1 with the expected based-load obtained with the help of (2), shows that there is a deficit of capacity to supply base-load power from 2016 to 2021. This is due to a relatively limited generation capacity in this time interval, as explained in Section 3.2.7. For Scenario 2, there is also an extra 262 MW deficit of power from 2018 to 2021 compared to Scenario 1, which is due to the differences in the projected new nuclear units that could be located in Bruce and Toronto zones. The possible supply alternatives for covering this power deficit include power imports from neighbouring grids, contributions from further conservation, renewable and CHP resources in excess of planned levels, and contributions from intermediate-load resources such as combined cycle gas turbines [44]. Since there are strong tie lines with New York and Michigan, and an Ontario-Quebec HVDC interconnection is scheduled to be operational by 2010 [46], the base-load deficit is assumed here to be supplied by power imports.

3.4. Imports/Exports in Ontario

Since there is surplus capacity during the base load periods in Bruce zone, the possibility of power exports to Michigan through the West zone has been considered. Moreover, a maximum of 1500 MW power imports from New York and Quebec during 2015-2021 is assumed for the East zone. Since power flows are typically from south to north in Ontario during the base-load time intervals, incurring in considerable power losses, power imports in both NE and NW from Quebec and Manitoba/Minnesota, respectively, are also considered in this study. Thus, a maximum of 150 MW and 500 MW imports in NE and NW, respectively, are assumed from 2015 to 2021. Also, a maximum of 150 MW import in NW is assumed in other years within the planning period.

3.5. Ontario's hydrogen generation and demand

3.5.1. Hydrogen generation

The hydrogen economy, which is considered in this study, is solely based on electrolytic hydrogen production for transportation purposes. This does not account for any increased production from SMR, and assumes that the current industrial demand for hydrogen remains constant and met by current production plants. The transfer of the industrial demand from SMR (which contributes to CO_2 emission), to CO_2 free electrolysis from nuclear is the subject of future analysis. In this work the operation time of the electrolysis plants is impacted by technical considerations as well as by the electricity prices and load levels on the electricity network as follows:

- *Technical considerations*: If the plant is switched on (i.e., from a stand-by state), it has to continue operating for a couple of hours, since extended interruptions of current cause damage to the plant due to the considerable shifts of temperature and pressure. For the same reason, both start up and shut down of the plant require some time because abrupt changes of current are not permitted [55].
- *Electricity price and demand*: Ontario's IESO defines the on-peak and off-peak time intervals as 7 am to 11 pm, and 12 am to 7 am, respectively. All weekends and holidays are also considered as off-peak. This gives an indication of the operation time periods when the hydrogen production plants could take advantage of the low electricity price and demand in the system for both economic and reliability considerations. Therefore, it is assumed here that the operating time for hydrogen production plants is 8 hours (12 am-7 am) during weekdays, considering that, according to the IESO, Hour 1 is 12 am - 1 am, and Hour 8 is 7 am - 8 am, and for the weekends, different operation times ranging from 12 to 24 hours were investigated. Based on the data provided in [54], average electricity demand as well as the HOEP for the different time frames considered were calculated and are illustrated in Tables 3 and 4.

Table 3 - Average zonal electricity demand of Ontario in different time frames for 2007 (MW).

	Average electricity demand [MW]										
Time period	**Bruce**	**West**	**SW**	**Niagara**	**Toronto**	**East**	**Ottawa**	**Essa**	**NE**	**NW**	**Total**
Weekdays during 12 am-7 am (8 hours)	71.02	1667.65	2982.16	593.62	5038.52	943.34	1097.99	805.83	1353.97	634.05	15188.15
Weekends during 12 am-11 am (12 hours)	70.49	1578.90	2857.13	552.70	4853.44	938.63	1126.93	820.19	1364.76	629.01	14792.17
Weekends during 12 am-1 pm (14 hours)	71.63	1615.37	2915.64	558.82	4995.19	961.15	1156.18	845.11	1375.36	630.44	15124.88
Weekends during 12 am-3 pm (16 hours)	72.32	1641.87	2955.29	563.45	5094.71	977.63	1173.75	859.99	1382.06	629.65	15350.72
Weekends during 12 am-5 pm (18 hours)	72.95	1665.23	2992.27	568.52	5175.67	993.10	1193.65	874.71	1388.09	628.10	15552.29
Weekends during 12 am-7 pm (20 hours)	73.56	1687.07	3030.35	573.60	5254.37	1007.99	1216.93	892.35	1392.99	627.63	15756.84
Weekends during 12 am-9 pm (22 hours)	73.95	1703.47	3057.89	577.08	5312.00	1017.58	1232.03	904.62	1397.85	629.62	15906.07
Weekends during 12 am-11 pm (24 hours)	73.93	1706.89	3061.19	576.71	5324.42	1018.22	1231.40	905.08	1399.20	631.82	15928.84

Table 4 - Hourly Ontario energy price.

	Average HOEP [CAD/MWh]				
Time period	**2003**	**2004**	**2005**	**2006**	**2007**
Weekdays during 12 am-7 am (8 hours)	37.64	35.25	46.07	32.50	31.95
Weekends during 12 am-11 am (12 hours)	39.07	36.73	48.15	33.57	32.73
Weekends during 12 am-1 pm (14 hours)	42.34	39.01	51.45	36.01	35.17
Weekends during 12 am-3 pm (16 hours)	43.40	40.09	53.47	37.15	36.41
Weekends during 12 am-5 pm (18 hours)	44.10	40.81	54.92	37.80	37.52
Weekends during 12 am-7 pm (20 hours)	45.49	42.28	57.11	38.86	38.92
Weekends during 12 am-9 pm (22 hours)	46.96	43.26	58.55	39.97	39.90
Weekends during 12 am-11 pm (24 hours)	46.99	43.29	58.33	40.03	39.77

Although more hours of operation during the weekends increase the capacity factor of the HPPs, observe in Tables 3 and 4 that electricity prices and, in particular, the average zonal demands increase, which in turn limits the possibility of adding extra load in the form of HPPs. Moreover, further hours of operation do not necessarily bring about significant economic advantages as discussed next.

To further investigate the economic impact of operation hours during the weekends, a literature survey was performed regarding the investment costs for different components of a hydrogen production unit, considering size and economies of scale [56-63]. A unit of 60 Nm^3/h (5.38 kg/h) capacity was considered in this study. The assumed investment costs of electrolyzer and compressor are $84,500 and $4,500 CAD per kg/h of hydrogen flow, respectively, and for storage $600 CAD/kg is assumed. These results in total investment costs of $504,767 CAD for the base unit assumed. Based on a HHV of hydrogen and a typical 70% efficiency for the whole unit [9], the total demanding power of the unit is found to be almost 300 kW. The share of the electrolyzer from this demanding power is calculated to be approximately 262 kW. This results in electrolyzer investment costs of 1736 CAD/kWe. Also, 3% of the total initial investment for the whole unit is assumed to be the average annual operation and maintenance costs; these include labour, insurance, property tax, licensing, maintenance, and repair [20,62].

Note that Table 4 shows in general declining off-peak electricity prices; however, considering the expected price increase during 2016-2021 due to relatively limited generation capacity, the average HOEP in 2007 both in weekdays and weekends have been assumed to be the expected electricity prices during the lifetime of the plant. Based on typical discount rates of 8% and income tax rates in Ontario of 18.62%, and assuming a plant lifetime of 20 years (because of low capacity factor) and that 30% of the plant's initial investment costs will be covered by Ontario government incentive support programs [64], the minimum hydrogen selling prices which justify the investment were found for each of the operating time frames considered. The results of these analyses are shown in Table 5, together with the corresponding economic indices, i.e., NPV, IRR, and PI.

Table 5 - Minimum acceptable hydrogen prices for different operating time frames.

Operation hours during weekdays	8	8	8	8	8	8	8
Operation hours during weekends	12	14	16	18	20	22	24
Minimum hydrogen selling price [CAD/kg]	4.90	4.78	4.67	4.57	4.50	4.42	4.33
NPV [CAD]	1222.96	176.231	950.517	805.536	1656.26	309.526	1255.63
IRR [%]	8	8	8	8	8	8	8
PI [-]	1.00347	1.00050	1.00268	1.00226	1.00464	1.00086	1.00349

Observe in Table 5 that each additional 2 hours of operation during the weekends reduces the hydrogen price by almost $0.1 CAD, and the maximum price reduction that can be achieved based on 12 extra hours of operation is only $0.57 CAD. Hence, even if there is no limit on the load level in the system, a few hours of further operation during the weekends will not be of great economic importance.

Notice in Table 3 that the 14-hour average demand on weekends (during 12 am-1 pm) is closest to the 8-hour average demand on weekdays. Consequently, and based on the aforementioned economic analysis, these 14 hours were selected as the operation time of the hydrogen production plants during the weekends. Thus, considering the 8 hours of operation during the weekdays, a 68 hours total operation per week are assumed, which yields close to a 40% capacity factor for the hydrogen production plants.

3.5.2. Hydrogen demand

In order to find the hydrogen demand or required size of electrolytic hydrogen production plants in different zones of Ontario, it is first necessary to determine the number of cars in each zone during the 2008-2025 period, which in turn requires the zonal population levels during the planning period. Therefore, the population of cities and towns of more than 10,000 inhabitants were used to find the population of each zone, considering the geographic location of the zones. The population of each zone was then proportionally scaled up such that the sum of zonal populations would equal the 12,861,940 population estimate for Ontario on January 1, 2008, as per [65]. The annual base-load growth rate for each zone discussed in Section 3.3 was also used to find the zonal population in the study period. The total projected population of Ontario in 2025 estimated in this way (15,663,374) is equal to what is reported in [66], confirming the adequacy of the assumptions used here.

Based on the zonal population and the per capita number of cars, the required number of hydrogen-fuelled vehicles in the 2008-2025 period can be estimated. According to 2005 statistics [67], the per capita number of vehicles in Canada ranged from slightly more than 0.1 in Nunavut to 0.85 in Yukon, with a national average of 0.58. The corresponding figure for Ontario, having 6,727,791 vehicles in 2005 was 0.55. This value was considered to be valid during the planning study in this paper.

The hydrogen economy transition in Ontario is assumed to be as shown in Fig. 3, with an initial sluggish development up to 2013 due to the need for developing the needed hydrogen related infrastructure and the possible slow adoption of hydrogen-based vehicles, with a faster slope thereafter. This figure specifies the level of a hydrogen economy penetration in each year, i.e., percent of the total cars on the road to be fuelled by hydrogen, to meet the target value in 2025. Observe that 0.2*K*% in this figure, means that only 20% of the target value K can be realized by 2013. The target value K is increased in the model to find the maximum feasibility limit. This hydrogen economy transition is assumed to be similar in all 10 zones of Ontario.

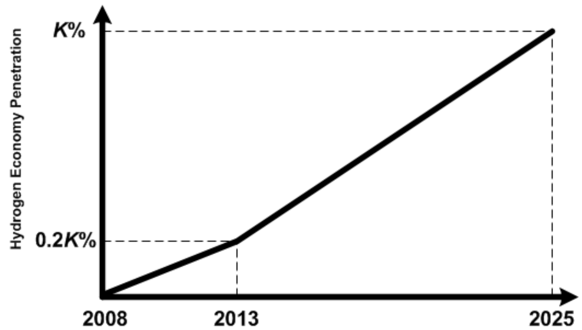


Fig. 3 - Assumed hydrogen economy transition in Ontario.

Based on 20,000 km annual mileage and 100 km/kg average fuel economy [20,28,68], the hydrogen demand of a light FCV is approximately calculated to be 0.55 kg/day. This number yields the daily hydrogen demand in each zone, considering the number of cars and the hydrogen economy penetration levels to be realized each year. For example, for a 1% hydrogen economy penetration, the total demand of hydrogen in Ontario in 2025 is found to be almost 47 ton/day, of which Toronto, SW and West would be the greatest consumers with almost 46%, 17%, and 9% share of the hydrogen demand, respectively.

The zonal hydrogen demand during the planning period allows for determination of the required capacity of the HPPs. Thus, based on HHV of hydrogen, the power requirement of a hydrogen production unit composed of a rectifier, electrolyzer, and compressor for 24 kg/day hydrogen production is equal to 56.36 kW, assuming a 70% efficiency. Based on 68 hours of operation per week, including 8 and 14 hours of operation during weekdays and weekends, respectively, the actual hydrogen production rate of this unit will be almost 9.7 kg/day. Therefore, the required size of the plant producing 1 ton/day hydrogen is equal to 5.8 MW based on 68 hours of operation per week. Figure 4 illustrates the zonal capacity of HPPs which would need to be developed in the 2008-2025 period to establish a 1% hydrogen economy penetration across Ontario; observe that almost 275 MW of power is needed by 2025, with a minimum share in Bruce zone with less than 600 kW and a maximum share in Toronto with more than 127 MW.

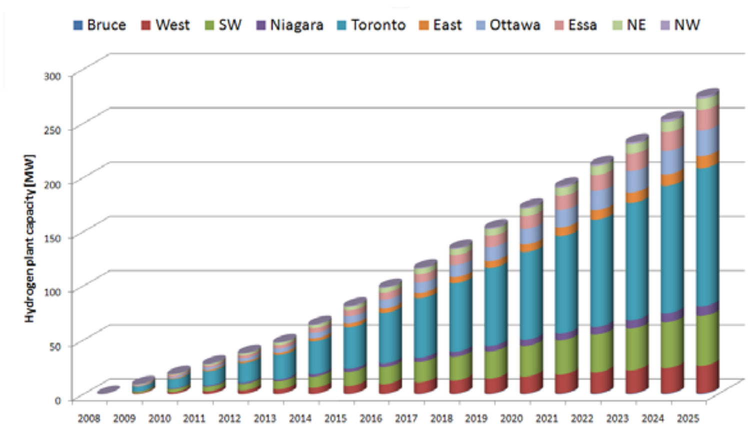


Fig. 4 - Zonal required capacity of electrolytic hydrogen production plants for 1% hydrogen economy realization.

3.5.3. Hydrogen transportation between the zones

In an ideal case, each zone should be able to cover its own hydrogen requirement. However, due to resource limitations in a couple of zones, power loss in transmission networks, assumed level of hydrogen economy penetration, or some operational or placement constraints, there may be a need for hydrogen transfer between particular zones in certain years. Among the possible modes of hydrogen transfer, i.e., compressed gas trucks, cryogenic tanker trucks and pipelines [69], the first mode was considered at this stage mainly because of economic considerations and greater availability of the required infrastructure compared to other options in the near term.

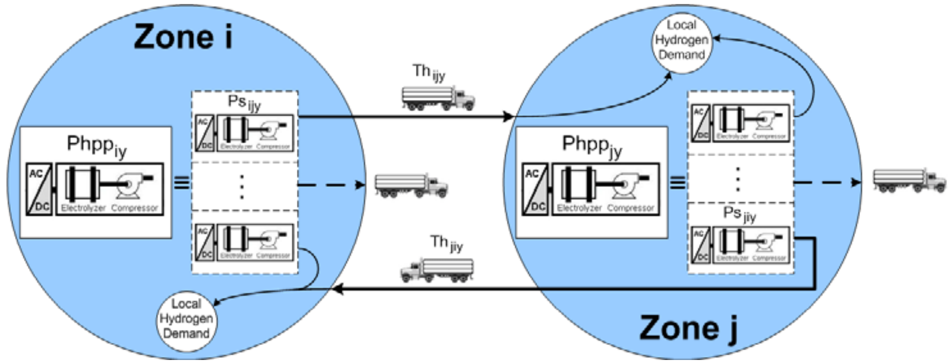


Fig. 5 - Demonstration of hydrogen transfer concept.

A simple demonstration of the hydrogen transfer concept is shown in Fig. 5, where both import and export possibilities exist for each zone. In general, the total installed HPP capacity in Zone i, by Year y ($Phpp_{iy}$) can be partly utilized for covering the local hydrogen demand as well as the hydrogen requirements of other zones. Hence, the total capacity of an HPP can be decomposed into multiple components, each of which covers a portion of the hydrogen requirement of other zones; for example, the power component Ps_{ijy} in Fig. 5 can be interpreted as the contribution of Zone i in total required power of HPPs in Zone j, which should be transferred to Zone j by compressed gas trucks. Similarly, other zones such as Zone j can share the required power of HPPs in Zone i based on a power component Ps_{jiy}. Based on this, the required MW capacity of HPPs for Zone i by Year y (Ph_{iy}), which supplies the local hydrogen demand, can be expressed as follows:

$$\begin{aligned} Ph_{iy} &= Phpp_{iy} - \sum_{j \neq i} Ps_{ijy} + \sum_{j \neq i} Ps_{jiy} \quad \forall i, j \in \mathrm{Z} \wedge y \in \Upsilon_1 \\ Phpp_{iy} &= Phpp_{iy-1} + \Delta Phpp_{iy} \end{aligned} \tag{4}$$

where $\Delta Phpp_{iy}$ is the newly installed HPP in Zone i and Year y; Z = {1,…,10} is the set of indices of zones or buses in the simplified network; and Υ_1 = {2009,…,2025} is the set of indices of planning years starting in 2009. Note that Ph_{iy} for a 1% hydrogen economy penetration is illustrated in MW in Fig. 4.

In order to link the power component Ps_{ijy} (MW) to transferred hydrogen Th_{ijy} (ton/day), one should note the operation hours or the capacity factor of HPPs. Thus, based on previously presented arguments in Section 3.5.1 with regard to the HHV of hydrogen, 68 hours of operation per week, and 70% efficiency for the total plant, on average, the Ps_{ijy} (MW) component in Zone i is capable of producing 0.1724 Ps_{ijy} (ton/day) hydrogen to be transferred to Zone j by compressed gas tube trailers. Therefore, the following relation can link the power components of HPPs in terms of MW to transferred hydrogen in terms of ton/day:

$$Th_{ijy} = 0.1724 Ps_{ijy} \quad \forall (i, j) \in \mathrm{Z}^* \wedge y \in \Upsilon \tag{5}$$

where Z^*= {(i,j): i,j ∈ Z, $i \neq j$} is the set of indices of hydrogen transfer corridors; and Υ = {2008,…,2025} is the set of indices of planning years starting from 2008.

The cost of hydrogen transportation based on compressed gas trucks is composed of operation and investment cost components. The investment costs correspond to truck cabs and compressed gas tube trailers, and the operation costs include diesel costs and driver wages, as well as insurance, licensing, maintenance, and repair costs [62,69,70]. The corresponding parameters for 2008 which are assumed in this study are illustrated in Table 6.

Table 6 - Hydrogen transportation cost parameters.

Maximum capacity of compressed gas trucks [ton]	0.4
Cab capital cost [CAD]	100,000
Tube trailers capital cost [CAD]	240,000
Diesel cost [CAD/km]	0.4212
Insurance, licensing, maintenance and repair costs [CAD/km]	0.4
Driver wage [CAD/km]	0.3
Cab lifetime [year]	5
Tube trailers lifetime [year]	20

Total operation costs of hydrogen transfer between Zones *i* and *j* are assumed to be a step function that depends on the amount of transferred hydrogen, and can be expressed as follows:

$$TOC_{ijy} = m \cdot OC_y \cdot d_{ij} \tag{6}$$

where m stands for the number of trucks, OC_y represents the operation costs of one compressed gas truck in Year y in \$CAD/km, and d_{ij} is the approximate distance between Zones i and j in km. Based on the data provided in Table 5, the operation costs of a compressed gas truck amount to \$1.1212 CAD/km for 2008. Based on typical inflation rates in Ontario, it is assumed that this operation costs will increase at 2.5% per year for the following years up to 2025. Finally, assuming that truck cab prices will probably rise due to inflation, but tube trailer prices will likely decrease since nowadays these prices could be considered high, it was assumed that the total investment costs for both combined could be considered to remain approximately constant during the planning years.

4. Optimization model

As previously argued, it is assumed here that the hydrogen demand for transportation purposes in each zone of Ontario would be fulfilled by the operation of electrolytic HPPs during the base load time intervals. Therefore, the purpose of the proposed optimization model is to determine the optimal size of the HPPs to be installed in different zones of Ontario between 2009 and 2025, as well as achieving a feasible target value of hydrogen economy penetration. This model also allows for determination whether each zone is capable of covering its own hydrogen demand by locally installed HPPs or if there is a need for hydrogen transportation between some particular zones. This section details the optimization model formulation by first describing the objective function and then discussing the required problem constraints, which result in a MILP optimization problem.

4.1. Objective function

The model's objective is to minimize the total electricity and hydrogen transportation costs. Thus, the objective cost function consists of both electricity generation and imported/exported power cost/revenue components during 8 weekday hours (12 am-7 am) and 14 weekend hours (12 am-1 pm), as well as hydrogen transportation costs, all during the years of 2008-2025:

$$\begin{aligned}\sum_{y\in\Upsilon_1}\sum_{i\in Z}\Big\{&\left(Pg_{iy}^{\omega_1}+Pim_{iy}^{\omega_1}-Pex_{iy}^{\omega_1}\right).HOEP_y^{\omega_1}\times 8\times 261\\&+\left(Pg_{iy}^{\omega_2}+Pim_{iy}^{\omega_2}-Pex_{iy}^{\omega_2}\right).HOEP_y^{\omega_2}\times 14\times 104\Big\}\\+\sum_{y\in\Upsilon_1}\sum_{(i,j)\in Z^*}&\left(\sum_{m=1}^{ntr_y} m\cdot K_{mijy}\right)\left\{2OC_y\cdot d_{ij}\times 365+\frac{DR\cdot CC_{cab}}{\left[1-\left(1+DR\right)^{-LT_{cab}}\right]}+\frac{DR\cdot CC_{tube}}{\left[1-\left(1+DR\right)^{-LT_{tube}}\right]}\right\}\end{aligned} \tag{7}$$

where:

- ω_1 is an index for the time period corresponding to 8 weekday hours (12 am-7 am).
- ω_2 is an index for the time period corresponding to 14 weekend hours (12 am-1 pm).
- Pg_{iy}^{ω} , Pim_{iy}^{ω} and Pex_{iy}^{ω} are zonal generation power, imported power, and exported power, respectively, in Zone i, Year y, and during the time period ω_1 or ω_2.

- K_{mijy} is a binary variable which takes the value of 1 if *m* trucks are needed for daily hydrogen transfer between Zones *i* and *j* in Year *y*.
- CC_{cab} and CC_{tube} are the capital cost of cab and tube trailers, respectively.
- LT_{cab} and LT_{tube} are the life time of cab and tube trailers, respectively.
- DR is the discount rate, and
- ntr_y is the maximum number of compressed gas trucks for daily hydrogen transfer in route between Zones *i* and *j* in Year *y*.

4.2. Constraints

4.2.1. Transmission system model

Power flows through the electricity network are generally used to represent the grid; this results in a set of nonlinear algebraic equations. However, using these equations to model the grid in optimization problems leads to a non-convex, NLP problem which presents several computational issues, such as convergence problems and multiple optima [71]. Hence, given the nature of the presented studies which only required an approximate representation of the grid, a dc power flow model that accounts for the transmission system losses is adopted here [71]. This model is explained in detail next.

The power losses in Line *(i,j)* of the electricity network can be approximately calculated as:

$$Ploss_{ij} \cong g_{ij}\left(\delta_i - \delta_j\right)^2 \tag{8}$$

where g_{ij} is the conductance of the line between buses *i* and *j*, and δ denotes the corresponding bus voltage angles. Following the method proposed in [72], a linear approximation of power losses in Year *y* and during the time period $\gamma \epsilon \{\omega_1, \omega_2\}$ can be obtained using *L* piecewise linear blocks as follows:

$$\delta_{ijy}^{\gamma} = \left|\delta_{iy}^{\gamma} - \delta_{jy}^{\gamma}\right| \tag{9}$$

$$\delta_{ijy}^{\gamma} = \sum_{l=1}^{L} \delta_{ijy}^{\gamma}\left(l\right) \tag{10}$$

$$Ploss_{ijy}^{\gamma} = g_{ijy} \sum_{l=1}^{L} \alpha_{ijy}\left(l\right) \delta_{ijy}^{\gamma}\left(l\right) \tag{11}$$

where $\alpha_{ijy}(l)$ and $\delta_{ijy}^{\gamma}(l)$ denote the slope and value of the l^{th} block of voltage angle, respectively. Assuming that each angle block has a constant length $\Delta\delta_y$, the slope of the blocks of angles for all lines *(i,j)* can be calculated as:

$$\begin{aligned} &\alpha_{ijy}\left(l\right) = \left(2l-1\right)\Delta\delta_y \\ &\forall\left(i,j\right) \in \Omega \wedge y \in \Upsilon \end{aligned} \tag{12}$$

A linear expression of the absolute value in Eq. 9 is also required, which is obtained by means of the following constraints:

$$\begin{aligned} &\delta_{ijy}^{\gamma} = \delta_{ijy}^{\gamma+} + \delta_{ijy}^{\gamma-} \\ &\delta_{iy}^{\gamma} - \delta_{jy}^{\gamma} = \delta_{ijy}^{\gamma+} - \delta_{ijy}^{\gamma-} \\ &\delta_{ijy}^{\gamma+} \geq 0, \delta_{ijy}^{\gamma-} \geq 0 \\ &\forall\left(i,j\right) \in \Omega \wedge y \in \Upsilon \wedge \gamma \in \Psi \end{aligned} \tag{13}$$

where Ω is the set of indices of transmission lines and $\Psi=\{\omega_1,\omega_2\}$. The following constraints are also needed to enforce the adjacency of the angle blocks:

$$\begin{aligned} &\delta_{ijy}^{\gamma}\left(l\right) \geq 0 \\ &\forall\left(i,j\right) \in \Omega \wedge y \in \Upsilon \wedge \gamma \in \Psi \wedge l \in L_1 \end{aligned} \tag{14}$$

$$\mu_{ijy}^{\gamma}(l)\cdot\Delta\delta_y \le \delta_{ijy}^{\gamma}(l)$$
$$\forall(i,j)\in\Omega\wedge y\in\Upsilon\wedge\gamma\in\Psi\wedge l\in L_2 \tag{15}$$

$$\delta_{ijy}^{\gamma}(l)\le \mu_{ijy}^{\gamma}(l-1)\cdot\Delta\delta_y$$
$$\forall(i,j)\in\Omega\wedge y\in\Upsilon\wedge\gamma\in\Psi\wedge l\in L_3 \tag{16}$$

$$\mu_{ijy}^{\gamma}(l)\le \mu_{ijy}^{\gamma}(l-1)$$
$$\forall(i,j)\in\Omega\wedge y\in\Upsilon\wedge\gamma\in\Psi\wedge l\in L_4 \tag{17}$$

where $\mu_{ijy}^{\gamma}(l)$ is a binary variable which takes the value of 1 if the value of the l^{th} angle block for the line *(i,j)* is equal to its maximum value $\Delta\delta_y$; $L_1=\{1,\ldots,L\}$; $L_2=\{1,\ldots,L-1\}$; $L_3=\{2,\ldots,L\}$; and $L_4=\{2,\ldots,L-1\}$.

Considering the line losses model just described, the net power injected at Zone *i* can be represented as:

$$P_{iy} = \sum_{(i,j)\in\Omega}\left[\frac{1}{2}g_{ijy}\sum_{l=1}^{L}\alpha_{ijy}(l)\delta_{ijy}^{\gamma}(l)-b_{ijy}\left(\delta_{iy}^{\gamma}-\delta_{jy}^{\gamma}\right)\right] \tag{18}$$

where b_{ijy} is the susceptance of the line *(i,j)* in Year *y*. Consequently, in general terms, the zonal power balance constraints can be formulated as follows:

$$Pg_{iy}^{\gamma}-Pl_{iy}^{\gamma}+Pim_{iy}^{\gamma}-Pex_{iy}^{\gamma}$$
$$-\sum_{(i,j)\in\Omega}\left[\frac{1}{2}g_{ijy}\sum_{l=1}^{L}\alpha_{ijy}(l)\delta_{ijy}^{\gamma}(l)-b_{ijy}\left(\delta_{iy}^{\gamma}-\delta_{jy}^{\gamma}\right)\right]=0 \tag{19}$$
$$\forall i\in Z\wedge y\in\Upsilon\wedge\gamma\in\Psi$$

where *Pl* is the total load in each zone and is comprised of zonal electricity demand (*Pe*) and total installed HPPs as follows:

$$Pl_{iy}^{\gamma}-Phpp_{iy}-Pe_{iy}^{\gamma}=0$$
$$\forall i\in Z\wedge y\in\Upsilon\wedge\gamma\in\Psi \tag{20}$$

4.2.2. Zonal power generation limits

Zonal power generation in each year is bounded by minimum and maximum limits $\underline{Pg}_{iy}$ and $\overline{Pg}_{iy}$, respectively. These limits are the minimum and maximum effective generation capacities which are available in each zone during the planning years as discussed in Section 3.2, resulting in the following inequality constraint:

$$\underline{Pg}_{iy}\le Pg_{iy}^{\gamma}\le\overline{Pg}_{iy}$$
$$\forall i\in Z\wedge y\in\Upsilon\wedge\gamma\in\Psi \tag{21}$$

4.2.3. Zonal import/export power limits

These limits are stated as:

$$\underline{Pim}_{iy}\le Pim_{iy}^{\gamma}\le\overline{Pim}_{iy}$$
$$\underline{Pex}_{iy}\le Pex_{iy}^{\gamma}\le\overline{Pex}_{iy} \tag{22}$$
$$\forall i\in Z\wedge y\in\Upsilon\wedge\gamma\in\Psi$$

where $\underline{Pim}_{iy}$ and $\overline{Pim}_{iy}$ are lower and upper bounds of imported power, respectively; and $\underline{Pex}_{iy}$ and $\overline{Pex}_{iy}$ are exported power minimum and maximum limits, respectively. These limits are set based on the arguments discussed in Section 3.4.

4.2.4. Transmission capacity constraints

These constraints are defined as:

$$\begin{aligned}
&b_{ijy}\left(\delta_{iy}^{\gamma}-\delta_{jy}^{\gamma}\right)+\frac{1}{2}g_{ijy}\sum_{l=1}^{L}\alpha_{ijy}\left(l\right)\delta_{ijy}^{\gamma}\left(l\right)\leq\overline{Pd}_{ijy}\\
&-b_{ijy}\left(\delta_{iy}^{\gamma}-\delta_{jy}^{\gamma}\right)+\frac{1}{2}g_{ijy}\sum_{l=1}^{L}\alpha_{ijy}\left(l\right)\delta_{ijy}^{\gamma}\left(l\right)\leq\overline{Pr}_{ijy}\\
&\forall\left(i,j\right)\in\Omega\wedge y\in\Upsilon\wedge\gamma\in\Psi
\end{aligned}\tag{23}$$

where $\overline{Pd}_{ijy}$ and $\overline{Pr}_{ijy}$ are maximum capacity of the transmission corridor *(i,j)* in Year *y* and in direct and reverse power flow, respectively.

4.2.5. Hydrogen demand and transportation constraints

These constraints are represented by Eqs. 4 and 5. Also, in order to model the hydrogen transportation costs in Eq. 7, the following constraints are needed:

$$\begin{aligned}
&\left[C\left(m-1\right)+\varepsilon\right]K_{mijy}\leq th_{mijy}\leq C\cdot m\cdot K_{mijy}\\
&\sum_{m=1}^{ntr_y}K_{mijy}\leq 1\\
&Th_{ijy}=\sum_{m=1}^{ntr_y}th_{mijy}\\
&\forall m\in\mathrm{M}\wedge\left(i,j\right)\in\mathrm{Z}^{*}\wedge y\in\Upsilon_1
\end{aligned}\tag{24}$$

where C is the truck capacity; ε is a very small positive number; th_{mijy} is an auxiliary variable representing the transferred hydrogen, since $Th_{ijy}=th_{mijy}$ if $K_{mijy}=1$; and $\mathrm{M}=\{1,\ldots,ntr_y\}$.

4.2.6. HPP size limits

These limits are represented by:

$$\begin{aligned}
&0\leq Phpp_{iy}\leq\overline{Phpp}_{iy}\\
&\forall i\in\mathrm{Z}\wedge y\in\Upsilon
\end{aligned}\tag{25}$$

where $\overline{Phpp}_{iy}$ is the maximum size of HPP which is allowed to be installed in Zone *i* by Year *y*. Since there is no installed HPP by the end of 2008, $\overline{Phpp}_{iy}$ is equal to zero for y = 2008.

5. Results and discussion

The optimization model proposed in Section 4 was coded in the AMPL mathematical modeling language [73] and then solved using the CPLEX solver [74]. The results of these simulations for the two generation-capacity scenarios introduced in Section 3.2.1 are presented and discussed in detail next.

5.1. Scenario 1 (assumes new nuclear reactors in 'Toronto zone')

The maximum level of hydrogen economy penetration that can be realized based on Scenario 1 was found to be equal to 2.79%. That is, without changes to the current planned development of the electricity generation and transmission network in Ontario, 2.79% of the light duty vehicles in Ontario can be converted to FCVs fuelled with hydrogen generated by electrolysis. In this case, all the zones are able to cover their own hydrogen requirements between 2008 and 2018 and in 2025; hence, hydrogen is only transported between 2019 and 2024. The main hydrogen importing zones are Ottawa and Essa, whereas Toronto and East are the main hydrogen exporters; Bruce and NW have no import or export activity during the planning study period.

Table 7 - Required HPPs ($\Delta Phpp_{iy}$) in MW for Scenario 1.

	Bruce	West	SW	Niagara	Toronto	East	Ottawa	Essa	NE	NW
2009	0.06	2.25	3.95	0.92	12.15	1.09	1.97	1.66	1.21	0.26
2010	0.06	2.32	4.08	0.93	12.39	1.11	2.04	1.71	1.20	0.26
2011	0.06	2.39	4.22	0.94	12.64	1.13	2.12	1.77	1.19	0.26
2012	0.06	2.46	4.36	0.95	12.89	1.15	2.20	1.82	1.17	0.26
2013	0.06	2.53	4.50	0.96	13.14	1.17	2.28	1.87	1.16	0.26
2014	0.10	4.22	7.51	1.59	21.91	1.95	3.80	3.12	1.94	0.44
2015	0.10	4.35	7.75	1.61	22.34	1.99	3.93	3.22	1.92	0.44
2016	0.11	4.47	8.00	1.63	22.78	2.02	4.08	3.31	1.90	0.44
2017	0.11	4.60	8.26	1.64	23.22	2.06	4.22	3.41	1.89	0.44
2018	0.11	4.73	8.52	1.66	23.67	2.10	4.37	3.51	1.87	0.44
2019	0.11	4.87	8.79	1.68	24.13	4.46	2.20	3.61	1.85	0.44
2020	0.11	5.01	9.07	1.69	24.60	6.81	0.04	3.72	1.83	0.44
2021	0.12	5.15	9.35	1.71	35.05	2.51	0.20	0.00	0.00	0.44
2022	0.12	1.78	0.36	5.24	47.82	0.00	0.00	0.00	0.00	0.45
2023	0.12	8.95	17.45	0.00	0.74	1.92	17.15	4.84	5.40	0.45
2024	0.12	5.59	12.01	0.00	19.56	0.01	7.68	11.12	1.77	0.45
2025	0.13	5.74	10.55	1.78	27.02	0.05	7.86	4.28	1.75	0.45
Total	1.65	71.40	128.72	24.93	356.04	31.54	66.13	52.98	28.05	6.62

The HPPs to be developed in different zones of Ontario during the planning years are shown in Table 7. Observe that the required HPPs in almost all the zones between 2009 and 2018 monotonically increase to supply the local hydrogen demand of each zone. The increase of HPP development in East, Toronto, and Niagara which take place in 2019, 2021 and 2022, respectively, shows that these zones become hydrogen exporters in these years. It is also worth noting that there is a significant increase in the required HPPs in the Niagara and Toronto export zones in 2022, while for the importing zones, i.e., West, SW, Ottawa, Essa, and NE, there is a significant change in 2023 and 2024.

Hydrogen export/import details for the study period are shown in Table 8. It is to be noted that East in 2021 acts as hydrogen importer from Toronto and hydrogen exporter to Ottawa with a net export of 1.25 ton/day. Observe that 2022 was found to be the most congested year from the viewpoint of hydrogen transportation among zones. For this year, the hydrogen transfer routes as well as the utilized % capacity of electricity zonal generation and transmission corridors are depicted in Fig. 6.

Table 8 - Hydrogen exports in ton/day for Scenario 1.

	Bruce	West	SW	Niagara	Toronto	East	Ottawa	Essa	NE	NW
2009	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0.4	-0.4	0	0	0
2020	0	0	0	0	0	1.2	-1.2	0	0	0
2021	0	0	0	0	1.72	1.6 (-0.35)	-2.00	-0.66	-0.31	0
2022	0	-0.61	-1.6	0.61	5.56	0.86	-2.86	-1.34	-0.62	0
2023	0	0	-0.3	0.3	1.2	0.8	-0.8	-1.2	0	0
2024	0	0	0	0	0	0.4	-0.4	0	0	0
2025	0	0	0	0	0	0	0	0	0	0

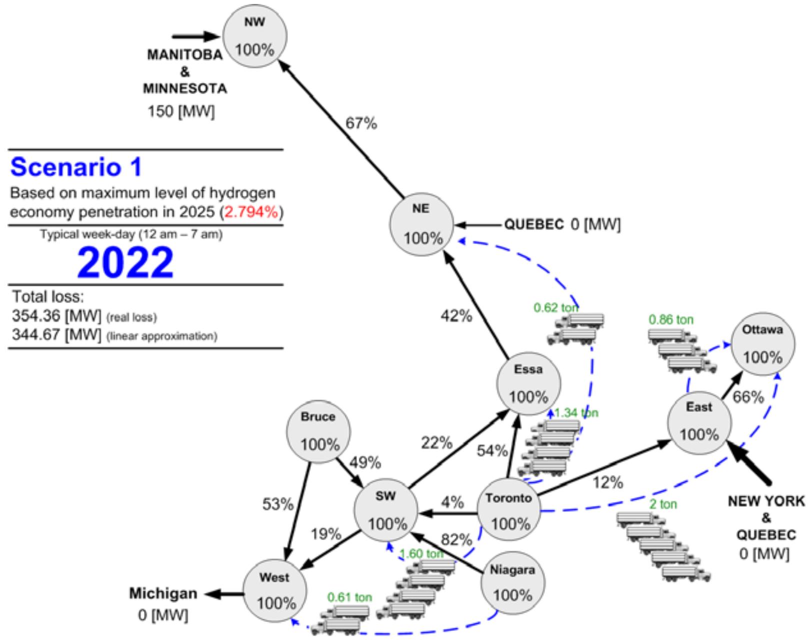


Fig. 6 – Hydrogen transportation, generation and transmission capacity utilization, and power flows in 2022 for Scenario 1.

5.2. Scenario 2 (assumes new nuclear reactors in 'Bruce zone')

The maximum level of hydrogen economy penetration that can be achieved in this case was found to be equal to 1.23% of the light duty vehicle fleet, which is lower than that obtained for Scenario 1. This can be explained in terms of the proximity of generation resources to load centres (i.e., where most of the vehicles are located). Thus, since the major demand for both electricity and hydrogen in Ontario are located in the Toronto zone, additional new generation capacity in this zone coming into service after 2018 in Scenario 1 permits a relatively higher level of hydrogen economy penetration. It should be highlighted that this extra capacity also reduces electricity losses and the need for hydrogen transportation. It should be mentioned that the study accounts somewhat for land availability and/or public acceptance of new power production and hydrogen production plants, which may vary from zone to zone, in the form of placement constraints.

Table 9 - Required HPPs ($\Delta Phpp_{iy}$) in MW for Scenario 2.

	Bruce	West	SW	Niagara	Toronto	East	Ottawa	Essa	NE	NW
2009	0.02	0.99	1.74	0.40	5.34	0.48	0.87	0.73	0.53	0.11
2010	0.03	1.02	1.80	0.41	5.45	0.49	0.90	0.75	0.53	0.11
2011	0.03	1.05	1.86	0.41	5.56	0.50	0.93	0.78	0.52	0.11
2012	0.03	1.08	1.92	0.42	5.67	0.51	0.97	0.80	0.52	0.12
2013	0.03	1.11	1.98	0.42	5.78	0.52	1.00	0.82	0.51	0.12
2014	0.04	1.86	3.30	0.70	9.64	0.86	1.67	1.37	0.85	0.19
2015	0.05	1.91	3.41	0.71	9.83	0.88	1.73	1.42	0.85	0.19
2016	0.05	1.97	3.52	0.72	10.02	0.89	1.79	1.46	0.84	0.19
2017	0.05	2.02	3.63	0.72	10.21	0.91	1.86	1.50	0.83	0.19
2018	0.05	2.08	3.75	0.73	10.41	0.92	1.92	1.54	0.82	0.19
2019	0.05	2.14	3.87	0.74	10.61	0.94	1.99	1.59	0.81	0.19
2020	0.05	2.20	3.99	0.75	10.82	0.96	2.06	1.64	0.81	0.20
2021	0.05	2.26	4.11	0.75	11.03	2.75	0.35	1.68	0.80	0.20
2022	15.05	2.33	4.24	2.31	0.41	0.00	0.00	0.00	0.00	0.20
2023	0.95	2.39	0.00	0.00	9.98	0.22	6.26	3.51	1.58	0.20
2024	0.00	2.46	0.00	0.00	17.00	1.02	2.36	1.83	0.78	0.20
2025	2.78	2.53	1.92	0.78	11.89	1.04	2.44	1.88	0.77	0.20
Total	19.29	31.41	45.02	10.97	149.65	13.87	29.09	23.30	12.34	2.91

The required HPPs in different zones of Ontario are presented in Table 9. Notice that the second largest yearly HPP development based on this scenario takes place in the Bruce zone in 2022. It is interesting to note that 78% of the total HPP development of Bruce during the study period occurs in 2022, which coincides with a small development in Toronto and no new installations in East, Ottawa, Essa, and NE. Also, the largest HPP developments in Ottawa, Essa, and NE happen in 2023.

Hydrogen export/import details for the study period are depicted in Table 10. Observe that hydrogen transportation between zones occurs between 2021 and 2025, with Toronto and SW being the main importing zone, while Bruce and East are the main exporting zones. Similar to Scenario 1, 2022 was also found to be the most congested year from the viewpoint of hydrogen transportation between zones; the corresponding hydrogen transfer routes as well as the utilized % capacity of electricity zonal generation and transmission corridors are shown in Fig. 7.

Table 10 - Hydrogen exports in ton/day for Scenario 2.

	Bruce	West	SW	Niagara	Toronto	East	Ottawa	Essa	NE	NW
2009	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0.31	-0.31	0	0	0
2022	2.59	0	0	0.27	-1.87	0.40	-1.09	0.69 (-0.99)	-0.14	0
2023	2.74	0	-0.75	0.13	-2.12	0	0	0	0	0
2024	2.73	0	-1.53	0	-1.2	0.4	-0.4	0	0	0
2025	3.20	0	-2.00	0	-1.2	0	0	0	0	0

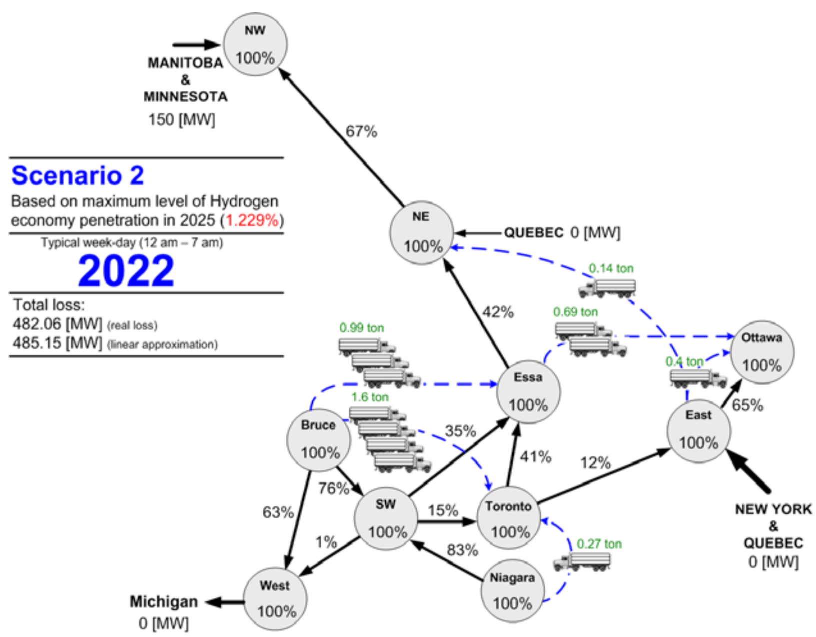


Fig. 7 - Hydrogen transportation, generation and transmission capacity utilization, and power flows in 2022 for Scenario 2.

5.3. Scenario 3 (Scenario 1 with HPP placement constraint)

Limiting the maximum size of developed HPPs in certain zones can influence the maximum level of achievable hydrogen economy penetration across the whole of Ontario; this is referred here as an HPP placement constraint to account for issues such as land availability and costs, public acceptance and zonal constraints, and its modeling was explained in Section 4.2.6. Thus, given the population density and land development issues in the Toronto zone, an HPP placement constraint was considered for this zone. As can be observed in Table 7, without a placement constraint, 768 MW of total HPPs in the different zones of Ontario during the study period are required for a maximum 2.79% hydrogen economy penetration; the HPP share of the Toronto zone is 356 MW in this case. If the total amount of HPPs in Toronto is kept between 250 and 50 MW, the remaining required HPP capacity should be covered by other zones, resulting in lower hydrogen economy penetration levels across Ontario as demonstrated in Table 11. Observe that this also results in an increase in hydrogen transportation costs, as expected.

Table 11 – Hydrogen economy penetration levels and transportation costs for Scenario 3.

Placement constraints [MW]	Hydrogen economy penetrations [%]	Hydrogen transportation costs [CAD]
0	2.794	24,340,879
250	2.781	102,838,812
200	2.388	113,402,339
150	1.996	125,839,348
100	1.604	147,233,513
75	1.407	161,341,053
50	1.211	177,747,148

5.4. Scenario 4 (Scenario 2 with HPP placement constraint)

A similar HPP placement constraint study for Scenario 2 was then carried out. In this case, with no placement constraint in the Toronto zone, the maximum 1.23% hydrogen economy penetration results in almost 338 MW of HPPs across Ontario, with 150 MW placed in Toronto. The results of applying the placement constraint are illustrated in Table 12, which shows that this constraint does not substantially influence the hydrogen economy penetration; however, the hydrogen transportation costs being significantly larger. This is to be expected, since in this scenario, the new electricity generation capacity is developed in Bruce as opposed to Toronto, as in the case of Scenario 1.

Table 12 - Hydrogen economy penetration levels and transportation costs for Scenario 4.

Placement constraints [MW]	Hydrogen economy penetrations [%]	Hydrogen transportation costs [CAD]
0	1.229	21,830,138
100	1.228	45,844,201
75	1.228	98,141,911
50	1.211	178,802,957

5.5. Discussion and comparison

Based on the performed studies, it is apparent that Scenario 1 can yield higher hydrogen economy penetration levels with electrolytic hydrogen in Ontario; however, with a placement constraint in Toronto zone this advantage disappears. In particular, from Tables 11 and 12, for a 50 MW placement constraint both scenarios yield the same level of maximum hydrogen economy penetration, i.e., 1.21%. This allows comparing various technical and economic issues to better understand the differences between Scenarios 1 and 2.

The required HPPs for each year in the planning period at a 1.21% maximum hydrogen economy penetration are shown in Tables 13 and 14 for each respective scenario. Observe that the maximum HPP level in Toronto (50 MW) is achieved by 2017 under both scenarios, and the HPP development pattern in Niagara, Toronto, Ottawa, NE, and NW are exactly the same, with other zones showing some differences after 2019 (highlighted in bold in Table 14). It is interesting to note that the major HPP developments under both scenarios in all zones, except West and East, occur in similar years; furthermore, the HPP development in East is the most influenced by the given scenario. In spite of the various differences in the required yearly HPPs for both scenarios, the total installed HPPs in each zone by the end of the planning years are the same, as showed in Table 15. This table also shows how different zones contribute to cover the required hydrogen demand in Toronto; in particular, Bruce represents the largest ratio of total installed HPP capacity to hydrogen demand.

Table 13 - Required HPPs ($\Delta Phpp_{iy}$) in MW for Scenario 1 with 1.21% maximum hydrogen economy penetration and 50 MW HPP placement constraint in Toronto.

	Bruce	West	SW	Niagara	Toronto	East	Ottawa	Essa	NE	NW
2009	0.02	0.98	1.71	0.40	5.27	0.47	0.85	0.72	0.52	0.11
2010	0.02	1.01	1.77	0.40	5.37	0.48	0.89	0.74	0.52	0.11
2011	0.03	1.04	1.83	0.41	5.48	0.49	0.92	0.77	0.51	0.11
2012	0.03	1.07	1.89	0.41	5.59	0.50	0.95	0.79	0.51	0.11
2013	0.03	1.10	1.95	0.41	5.70	0.51	0.99	0.81	0.50	0.11
2014	0.04	1.83	3.25	0.69	9.50	0.85	1.65	1.35	0.84	0.19
2015	0.04	1.88	3.36	0.70	9.68	0.86	1.71	1.39	0.83	0.19
2016	0.05	1.94	3.47	7.67	2.91	0.88	1.77	1.44	0.83	0.19
2017	0.05	1.99	8.22	5.35	0.52	0.89	1.83	1.75	0.82	0.19
2018	0.05	2.05	10.56	0.72	0.00	0.91	1.89	4.82	0.81	0.19
2019	4.69	2.11	3.81	0.73	0.00	0.93	1.96	7.38	0.80	0.19
2020	7.01	4.49	3.93	0.73	0.00	0.94	2.03	2.99	0.79	0.19
2021	0.05	4.55	4.05	0.74	0.00	10.24	2.10	0.92	0.79	0.19
2022	0.05	9.25	4.18	0.75	0.00	3.30	2.39	3.27	0.78	0.19
2023	0.05	2.36	4.31	0.76	0.00	0.99	13.53	1.75	0.77	0.19
2024	0.05	2.42	4.44	0.76	0.00	1.01	2.22	1.80	12.37	0.19
2025	0.05	2.49	4.57	0.77	0.00	1.03	2.60	1.85	0.76	11.71

Table 14 - Required HPPs ($\Delta Phpp_{iy}$) in MW for Scenario 2 with 1.21% maximum hydrogen economy penetration and 50 MW HPP placement constraint in Toronto. Differences with respect to Table 13 are highlighted in bold.

	Bruce	West	SW	Niagara	Toronto	East	Ottawa	Essa	NE	NW
2009	0.02	0.98	1.71	0.40	5.27	0.47	0.85	0.72	0.52	0.11
2010	0.02	1.01	1.77	0.40	5.37	0.48	0.89	0.74	0.52	0.11
2011	0.03	1.04	1.83	0.41	5.48	0.49	0.92	0.77	0.51	0.11
2012	0.03	1.07	1.89	0.41	5.59	0.50	0.95	0.79	0.51	0.11
2013	0.03	1.10	1.95	0.41	5.70	0.51	0.99	0.81	0.50	0.11
2014	0.04	1.83	3.25	0.69	9.50	0.85	1.65	1.35	0.84	0.19
2015	0.04	1.88	3.36	0.70	9.68	0.86	1.71	1.39	0.83	0.19
2016	0.05	1.94	3.47	7.67	2.91	0.88	1.77	1.44	0.83	0.19
2017	0.05	1.99	8.22	5.35	0.52	0.89	1.83	1.75	0.82	0.19
2018	0.05	2.05	10.56	0.72	0.00	0.91	1.89	4.82	0.81	0.19
2019	**2.37**	2.11	3.81	0.73	0.00	**3.25**	1.96	7.38	0.80	0.19
2020	**9.33**	**2.17**	**3.10**	0.73	0.00	**3.26**	2.03	**1.50**	0.79	0.19
2021	0.05	**11.51**	**4.89**	0.74	0.00	**0.96**	2.10	**2.41**	0.79	0.19
2022	0.05	**4.61**	4.18	0.75	0.00	**7.94**	2.39	3.27	0.78	0.19
2023	0.05	2.36	4.31	0.76	0.00	0.99	13.53	1.75	0.77	0.19
2024	0.05	2.42	4.44	0.76	0.00	1.01	2.22	1.80	12.37	0.19
2025	0.05	2.49	4.57	0.77	0.00	1.03	2.60	1.85	0.76	11.71

Table 15 - Total installed and local HPP capacities for both scenarios with 1.21% maximum hydrogen economy penetration and 50 MW placement constraint in Toronto.

	Bruce	West	SW	Niagara	Toronto	East	Ottawa	Essa	NE	NW
Total installed HPPs by 2025 [MW]	12.32	42.55	67.39	22.41	50.00	25.27	40.26	34.56	23.76	14.38
Required HPPs for local hydrogen demand [MW]	0.72	30.95	55.79	10.81	154.32	13.67	28.66	22.96	12.16	2.87

The impact of the developed HPPs on the electricity system is demonstrated in Table 16, in which the transmission system losses for both scenarios are shown. Observe that Scenario 2 shows minor advantages between 2013 and 2016. However, between 2018 and 2025, the total electricity losses for Scenario 2 are greater than those for Scenario 1, resulting in the 0.2% total electricity costs increase in the study period shown in Table 17. This table also shows a 0.6% increase in the hydrogen transportation costs of Scenario 2 with respect to Scenario 1.

Table 16 - Total transmission losses during off-peak periods for both scenarios with 1.21% maximum hydrogen economy penetration and 50 MW placement constraint in Toronto.

	Energy loss [MWh]	
	Scenario 1	**Scenario 2**
2009	1,579,302	1,579,302
2010	1,503,410	1,503,410
2011	1,615,846	1,633,805
2012	1,642,524	1,655,009
2013	1,909,592	1,888,493
2014	1,984,694	1,961,951
2015	1,422,886	1,403,590
2016	1,609,975	1,588.128
2017	1,578,050	1,578,050
2018	906,288	1,609,775
2019	690,891	1,073,536
2020	602,480	843,673
2021	582,321	857,415
2022	1,198,793	1,731,770
2023	1,320,522	1,874,457
2024	1,757,255	2,648,831
2025	1,802,732	2,670,790
Total	23,707,561	26,515,445

Table 17 - Hydrogen economy maximum penetration levels and costs comparison for 50 MW placement constraint in Toronto.

	Maximum hydrogen economy penetrations [% of Vehicles in Ontario]	**Total electricity costs [CAD]**	**Total hydrogen transportation costs [CAD]**
Scenario 1	1.211	36,600,866,338	177,747,148
Scenario 2	1.211	36,674,241,845	178,802,957

5.6. Sensitivity analysis

To study the impact of HPP efficiencies, which is probably the most relevant uncertainty in the proposed model, a sensitivity study of the penetration levels with respect to variations on this parameter was performed. Therefore, a range of 1% to 30% efficiency improvements, which correspond approximately to a 70% to 91% HPP efficiency range, during the time period 2008-2025 was considered for Scenario 1. The main results obtained are illustrated in Fig. 8; observe that the maximum hydrogen economy penetration levels in Ontario by 2025 vary almost linearly with respect to HPP efficiencies.

Although a 30% efficiency improvement (91% HPP efficiency) by 2025 may not be achievable or even realistic in practice, it is informative, as it allows determining an upper limit for maximum Ontario's grid potential with respect to HPP efficiencies for supporting hydrogen-powered vehicles. Thus, for the maximum efficiency improvement considered, a maximum hydrogen economy penetration level of 3.52% can be achieved, which translates into almost 302,000 FCVs in Ontario's transport sector by 2025.

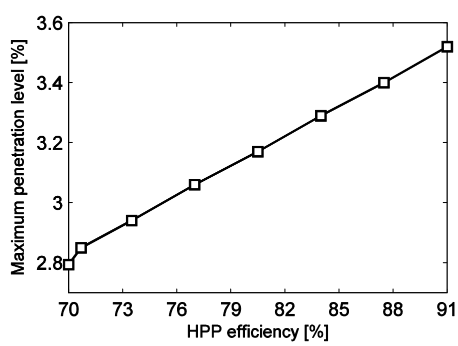


Fig. 8 – Maximum hydrogen economy penetration level in Ontario with respect to HPP efficiency.

6. Conclusions

The feasibility of electrolytic hydrogen production in Ontario during off-peak periods based on the existing and planned electricity system was studied in this paper. Inspired by the notion of efficient utilization of the existing infrastructure and the concept of integrated energy systems, an optimization model was developed for an integrated electricity and hydrogen system in Ontario. This optimization model, which is based on a zonal model of Ontario's transmission network and base-load generation capacity between 2008 and 2025, is used to find a maximum hydrogen economy penetration of light duty hydrogen vehicles that can be achieved by 2025, as well as the optimal size of HPPs to be developed in different zones of Ontario and the optimal hydrogen transportation routes. The presented studies show that at least a 1.2% hydrogen economy penetration (or approximately 103,000 light duty hydrogen vehicles) can be achieved in Ontario by 2025 without changes to the electricity production and transmission system to specifically accommodate the hydrogen economy, i.e., the model specifically considers the existing and planned enhancements for both electricity generation resources and the transmission network, and the use of electrolysis for the generation of hydrogen. Various uncertainties such as the location of new nuclear generation in Ontario or zonal specific constraints influence the maximum level of hydrogen economy penetration that can be realized; however, the proposed models and study procedures are general and hence independent of these assumptions, and could in principle be applied to any other location besides Ontario.

Certainly there are limitations of the presented models and studies. For example, environmental impacts and costs need to be represented, and changes to industrial demand and production of hydrogen are not included. Also, zonal electricity prices were not considered in the model, assuming a uniform price across the system, which is a reasonable assumption in Ontario; however, in other jurisdictions with LMPs, the model should be modified to account for the price differences among zones. Furthermore, given the uncertainty of some of the assumptions, such as the efficiency for the hydrogen production plants during the planning horizon, stochastic models and studies are currently being developed and performed and will be presented and discussed in future works.

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