Hybrid PV-systems and co-localization of charging and filling stations for electrification of road transport sector

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Abstract

Electrification of the road transport sector will likely include both battery-electric (BEV) and hydrogen fuel cell electric vehicles (FCEV). Integration of energy carriers has been described as a route forward for efficient integration of renewable energy. The objective of this work was to determine cost-efficiency improvements with co-localization of BEV and FCEV stations, and how this would impact optimal sizing of the PV production and battery storage. Grid-connected co-localized charging/filling stations situated north of Oslo, Norway, were modeled in Homer Pro and Homer Grid. PV production was modeled using PVsyst and a snow loss model to analyze the effect of snow shading on PV production. Demand data for BEV and FCEV was synthesized based on historical traffic data (year 2015-2019) to represent three different cases of BEV/FCEV distribution. Results indicate that co-localization, i.e., the integration of energy carriers for BEV and FCEV, leads to a marginal cost-efficiency improvement of 0.1-1.4%, depending on BEV/FCEV distribution and cost assumptions. Co-localization showed greater benefits for the integration of locally produced renewable power. Due to co-localization, the cost-optimal PV capacity was either increased or PV power export

was reduced. Stationary batteries were also observed to cost-efficiently perform peak shaving in a future scenario.

1. Introduction

Electrification of passenger cars is well established as both sales volumes and available models are accelerating. Electrification of heavy-duty trucks is currently also gaining momentum as both battery-electric, and fuel cell models are being realized. The drive towards electrification enables the addition of locally produced renewable electricity, and it has been shown that grid-connected distributed energy systems are the preferred choice for charging stations.[1] Besides providing favorable economic returns, PV-battery systems at charging stations have also been found to benefit the grid side and provide social benefits.[2] However, to our knowledge, this has not been shown for Norwegian conditions. The charging mode will also impact the benefits of PV-systems at charging stations, as fast-charging leads to more reliance on utility-grid and higher electricity costs.[3] To our knowledge, most papers on charging stations with PV-battery systems have analyzed smaller stations with PV-capacities below MW-scale. However, one larger utility-scale system for fast-charging in France was analyzed, where both battery electric cars and trucks were included.[4] They showed that integration of PV successfully could increase demand coverage along major road corridors outside Paris, and the payback time for a 15-year project lifetime was found to be 7.4 years.

Multi-carrier energy networks, i.e., the integration of different energy carriers in a system, has been shown to increase utilization of intermittent renewable energy.[5] Therefore, for efficient electrification of the transport sector, co-localizing hydrogen refueling stations with EV charging stations might be a means to incorporate more intermittent renewable energy to the electrification of the transport sector. Several published papers describe the optimization of both battery electric vehicles (BEV) and hydrogen fuel cell electric vehicles (FCEV), [6,7] but few of them explain the rationale for co-localization. Recently though, it was shown that co-localization of BEV and FCEV as a hybrid charging station reduced the net present cost by 2.1%.[8] The authors considered the demand for FCEV buses and BEVs and optimized local wind electricity generation in both on-grid and off-grid systems. However, their model was designed for depot-filling/charging and did not cover specificities around "on-the-road chargers".

The objective of this work was, therefore, to answer the question if charging stations for BEV and filling stations for FCEV should be co-localized for improved cost-efficiency, and moreover, how this co-localization would impact optimal sizing of on-site PV production and battery storage. This was conducted by comparing two cases: 1) separate FCEV and BEV stations, and 2) co-localization of BEV and FCEV stations.

2. Methods

System description: Two cases were included in the analyses. The first case represents separate BEV charging station for battery-powered vehicles and FCEV filling station for hydrogen fuel cell vehicles. The second case represents a co-localized station where both battery and fuel cell vehicles charge and fill at the same station. Local electricity generation with PV and energy storage in Li-ion batteries were included in all systems for determining how renewable energy and storage contributes to energy costs for electrification of the transport sector. The two cases are presented in Figure 1.

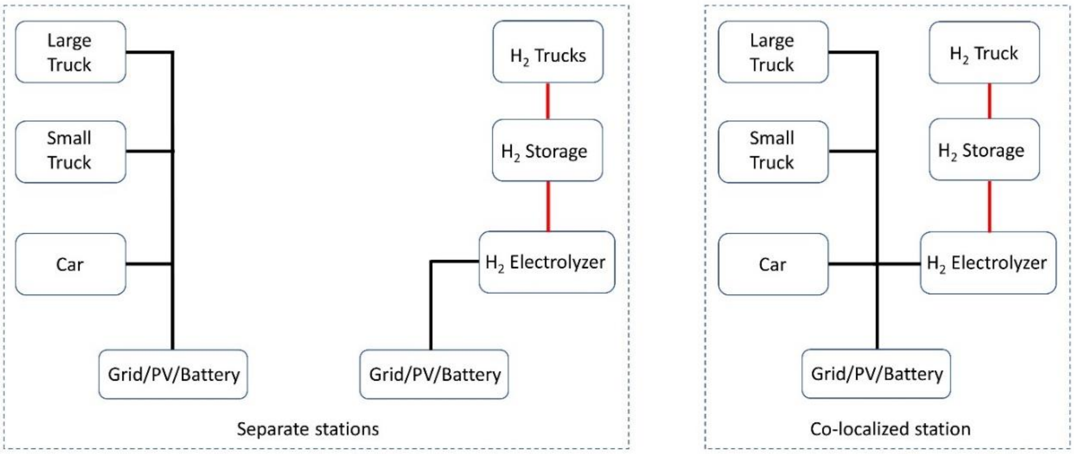


Figure 1. One-line diagram of the two cases where the left picture shows separate BEV and FCEV stations, and the right picture shows co-localized station.

Estimation of energy demand: In this paper, the electrification of vehicles was assumed for both light-duty (LD) and heavy-duty (HD) vehicles. The energy demand for the charging of batteries and filling of hydrogen storage tanks was estimated based on openly available traffic counts for 2015-2019 provided by the Norwegian Public Roads Administration. The location of data collection was at a major road north of Oslo, Norway. The location intersects two major transport corridors and was considered to capture most of the traffic flow between the two cities Oslo and Trondheim, hence a logical location for considering a significant "on-the-road" co-localized charging station. Data was collected as passes per hour for two different vehicle types, LD vehicles (< 5.6 m) and long HD trucks (>16 m). To better understand the traffic count data for HD trucks, a rigid truck with a trailer or a tractor unit with semi-trailer will typically be above 16 m length. While trucks without trailer are significantly shorter and mixes with lot of other car types, including private cars with trailers. Another aspect of the traffic counts is that it provides a single shot image of a specific location, while not revealing the driving lengths of the counted vehicles.

The road counts were complemented by national data of how the daily mileages of Norwegian trucks are divided by truck type and trip length and presented in **Error! Reference source not found.**. This information was used to increase the traffic count of trucks by 27.5%, representing the HD vehicles up to 16 m. This additional volume has been added evenly over the day. In this work, it is assumed that HD vehicles will be replaced by both BEV and FCEV, since FCEV are considered more feasible for long-haul operations.[9] To accommodate for this division, the share of FCEV is assumed to be similar to the share of daily truck mileage above 500 km, i.e. 25%. There is however a large uncertainty of the future development of zero-emission road freight, thereby a wider range of shares between BEV/FCEV were analyzed, 87.5%/12.5% and 62.5%/37.5%. The latter one can be interpreted as vehicle with daily milage above 300 km is powered by hydrogen, when considering the national statistics.[10]

This work does not consider potential future changes in traffic flow. However, we believe the utilization of traffic count data is a good approach for determining cost-efficiency of power flows and integration of renewable energy since it gives an indication of both volume and temporal resolution of charging and filling events.

To eventually calculate hydrogen load (kg/h) throughout a typical year, the historical data on passes per hour and share of FCEV was modified with the Homer Grid EV charging module to account for uncertainties in a day-to-day and time-step variability. 50% variability were used in both cases, and it was further assumed that 50% of the FCEV stop for filling at this station. The refueling amount for HD FCEV is hard to set as only one series-produced small/middle size hydrogen truck is available in Europe, with a refueling capacity of 32 kg.[11] Analysis of a tractor unit operating the route between Oslo and Trondheim concluded on an onboard storage of 46 kg,[12] while in previous hydrogen bus demo projects, the storage was 30-50 kg.[13] Based on this data an average refueling amount of 40 kg per HD vehicle was set.

Table 1. Distribution of mileage for HD vehicles in Norway.[10]

Vehicle		Share of total daily mileage among all HD vehicles	Daily mileage	
			<500 km	>500 km
Truck	w/o trailer	27.5%		
	with trailer	30.5%	75%	25%
Tractor unit with semi-trailer		42.1%		
Total		100%		

EV charging demand was calculated with the EV charging module in Homer Grid as hourly charging profiles (kWh/h) based on traffic count data. Charging power for LD vehicles was taken to represent the Norwegian car park of today.[14] Since the traffic count data shows passes per hour, and not actual stops at the station, it was assumed that 5% of cars and 25% of HD BEVs stopped for charging. Trucks were chosen to utilize 500 kW chargers, and the charging time was set to 40 minutes with 50% variability to represent charging of both small and large BEV trucks. Small trucks charging 500 kW in 20 minutes results in charge energy of 166 kWh and large trucks charge 500 kWh during 60 minutes. Day-to-day and time-step variability was the same as for FCEV trucks, i.e. 50%.

The average number of passes per day at the charging/filling station for the case with 75% BEV and 25% FCEV were 556 (cars), 286 (BEV truck), and 194 (FCEV truck). The corresponding yearly energy demand therefore equals 5 GWh (cars), 34 GWh (BEV trucks), and 94 GWh (FCEV trucks), assuming an energy density of 33.3 kWh/kg for hydrogen. To decide on the number of charging points for BEV, the peak number of passes per hour was used, and this resulted in 75 chargers for the cars and 25 for the trucks. The peak number of passes per hour for the FCEV trucks were 16.

Technoeconomic analyses: The technoeconomic analysis was designed to quantify net present costs (NPC) for single BEV, single FCEV and co-localized hybrid charging stations considering full electrification, meaning all cars and trucks are electrified by either batteries or fuel cells. The NPC for single BEV and single FCEV stations were added and compared with NPC for the hybrid charging station where both BEVs and FCEVs are charged/filled. The commercial modelling software HOMER Pro 3.13.8 and HOMER Grid 1.7.4 were used for quantifications of NPC. The software optimizes the system based on minimizing the objective function NPC, which is the value of all the costs the system incurs over its lifetime, minus the present value of all the revenue it earns over its lifetime.[15] Costs include capital costs, replacement costs, operation and maintenance costs, and the costs of grid electricity. Revenues include salvage value and grid sales revenue. The sequence modelling in Pro and Grid allows for a detailed simulation of electricity prices, where both energy (EUR/kWh) and power charges (EUR/kW) are considered. HOMER Pro was first used to optimize the size of the electrolyser and the hydrogen storage tank based on the estimated hydrogen load profile. The electricity consumption of the electrolyser was exported to HOMER Grid and added to the electricity demand. The total electricity profile was thereafter used to optimize the PV and battery system size. The PV-battery optimization in HOMER Grid deploys a dispatch strategy that uses a 48h perfect foresight. By using a rolling horizon approach the dispatch strategy considers the electricity price, the electricity load, and the PV production to schedule the charging and discharging of the battery. Maximum installed PV-capacity in the optimizations was restricted to peak demand in each of the stations. By using capacity restrictions, emphasis will be placed on covering the electricity demand at the stations rather than the export of electricity from a utility-scale PV-park. Revenues from export of electricity is however included in the NPC calculations. The project lifetime for NPC-calculations was set to 15 years, discount and inflation rate were set to 3.5% and 2% respectively.

Energy technology components at charging/filling station: PV production data has been simulated in PVsyst and exported to Homer Grid for dimensioning and optimization of net present cost in the three stations. Although HOMER have the ability for internal calculations of solar power production, the level of detail for PVsyst is higher and thus creates more realistic results. PVsyst includes three meteorological databases, each with its own benefits and limitations. These databases offer monthly meteorological data where hourly data can be generated through a built-in stochastic model. In this study we have used the PVGIS Typical Meteorological Year (TMY). Comparing simulations to field data, this database has proven to be the best fit for Norwegian locations. The coordinates for the specific location studied in this work was 60.70°N, 11.26°E. A PV system of 81.4 kWp was simulated, consisting of Longi Solar 370 Wp 29V LR-60 HPH 370 M G2 Si-mono PV modules, and Sungrow SG80KTL inverters with 20 modules in series and 11 module strings in parallel. The system was ground-mounted with a row distance of 8.5 meters, giving a total PV system area of approximately 1400 m^2. To find the optimal module tilt for the stations, the system was simulated with varying tilt. Row shading losses and 2 % monthly soiling losses were included in all simulations. The specific production for a system with 10° tilt was 861 kWh/kWp/year and the performance ratio was 88.2% (no specific snow losses). In PVsyst, snow losses are typically accounted for by increasing the monthly soiling loss value in the winter months. For the selected location, which can experience snowfalls in the winter, there is little available data on snow losses for PV systems, and reliable input for the PVsyst simulation is lacking. PV snow losses are expected to vary a lot between locations and system designs, and to get snow loss estimates for new systems, snow loss modeling is necessary. Some PV snow loss models exist, but validation is typically lacking.[16] The snow model suggested by Marion et al., [17] which is implemented in the simulation tools SAM and pvlib, has been shown to perform better than other available models.[18] The model is, however, not very well tested for ground-mounted PV systems, and it is possible that not all influential effects are included in the model, but we believe that the model is the best available tool for giving an indication of the snow losses for our location. To estimate monthly snow losses, the implementation of the Marion et al. model described by Øgaard et al.[19] was used. Using irradiance and temperature from PVGIS[20] and snow data from senorge.no[21], the monthly snow losses for 11 years (2005-2016) was modeled for PV systems with different tilts for south facing modules. The median snow loss value for each month was then selected as monthly soiling loss value input to the PVsyst model.

The battery system was modeled as separate battery and inverter components to allow for cost-efficient design of the energy and the power capacity. The battery component was modelled as a modified advanced storage module (ASM) Li-ion module in Homer Grid to represent the lithium-manganese-cobalt-oxide (NMC) technology. Lifetime was calculated from both cycle and calendar degradation, where 3000 cycles to 90% DOD and calendar lifetime of 15 years were used.[22, 23] Battery replacement was activated when either cycle or calendar degradation reached end-of-life. The power-to-capacity-rate (C-rate) of the battery was restricted to 1, the roundtrip efficiency was 95%, and the minimum state-of-charge (SOC) was 10%. No temperature effects were included since the battery is expected to be installed in temperature-controlled environments. The inverter component was modeled with an efficiency of 97%, a lifetime of 15 years, and a relative capacity of 100%, i.e. equal power for charging and discharging.

The cost of electricity was simulated according to a tariff structure that includes energy cost (EUR/kWh), power cost (EUR/kW), and a fixed monthly cost (EUR/month). Prices from Elvia, which is one of the largest utility companies in Norway, in 2021 was used as input.[24] In addition to prices from Elvia, spot prices for year 2019 were used. Spot prices have varied throughout the eight years with historic data, and year 2019 represents a price that is above the average of the past eight years but not the most expensive. Two price-levels were used in the analyses, one representing the case of today, and one for the year 2030. The future prices of 2030 were estimated to be about 20% higher than today, based on a yearly increase of 2%. All prices of today were scaled equally, i.e. both the energy, the power, and the fixed prices.

The electrolyzer for the FCEV station was modelled as a proton exchange membrane (PEM) module and was powered by electricity from both the grid and the PV-system. The operation range of the PEM module was 0-100% and the lifetime was set to 15 years, which equals 75 000 hours with a utilization factor of 57%. The efficiency was set to 57% (year 2020) and 65% (year 2030) and includes the electricity consumption of the compressor for the storage tank.[25] The 450 bar H2-storage tank was simulated as a steel tank with a lifetime of 10 years.

Two cost-scenarios were used in this paper, one for today (2020) and for year 2030. Cost assumptions of technology components are summarized in Table 2 and 3. Costs of dispensers (BET chargers and H_2-dispenser) at charging and filling stations have not been included in the analysis since these costs do not affect cost-efficiency of energy supply. A sufficient number of dispensers were needed to cover the energy demand for transportation, and these were assumed to be installed at the stations.

Table 2. Cost assumptions for 2020.

		Installation	Replacement	O&M	Ref
PV	EUR/kWp	800	400	1 %	27
Battery	EUR/kWh	340	255	1 %	28
Battery converter	EUR/kW	440	330	0[a)]	28
Electrolyzer	EUR/kW	1150	598	4 %	25, 26
H2 storage	EUR/kg	810	810	0[b)]	29

[a)] O&M for battery inverter is included in O&M for battery; [b)] O&M for H2-tank is included in O&M for electrolyzer and compressor.

Table 3. Cost assumptions for 2030.

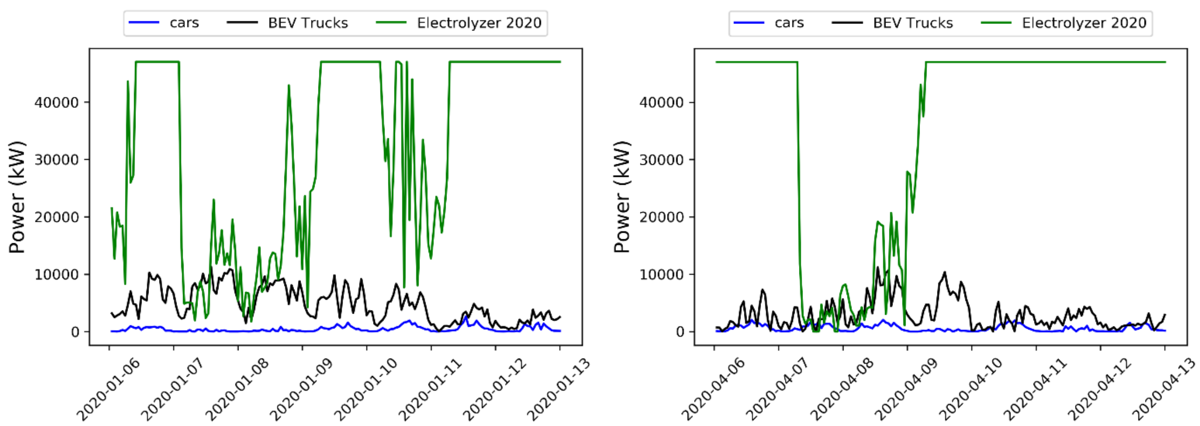
		Installation	Replacement	O&M	Ref
PV	EUR/kWp	500	250	1 %	27
Battery	EUR/kWh	170	128	1 %	28
Battery converter	EUR/kW	220	165	0[a)]	28
Electrolyzer	EUR/kW	820	430	4 %	25, 26
H2 storage	EUR/kg	810	810	0[b)]	29

[a)] O&M for battery inverter is included in O&M for battery; [b)] O&M for H2-tank is included in O&M for electrolyzer and compressor.

3. Results & Discussion

3.1 Load demand

Figure 2 presents the hourly electricity demand profiles for the 75% BEV and 25% FCEV case in year 2020 during four different weeks (Monday-Sunday) to represent winter, spring, summer, and autumn conditions. The hourly peak/average demand was 5 322/587 kW (cars), 11 958/3 840 kW (BEV trucks), and 34 000/22 365 kW (FCEV trucks). The electricity demand for filling of FCEV trucks is clearly higher than charging of battery electric vehicles. This is due to both the electric efficiency of electrolyzer and compressor (57%) and the larger share of passing vehicles that stop for hydrogen refilling. It was assumed that 50% of FCEV trucks stop for filling, whilst only 25% of BEV trucks stop for charging. The BEV charging infrastructure can relatively easily be installed wherever there is access to the power grid and most probably the cheapest recharging will be during nights at logistic depots in line with light-duty EV home charging. In combination with serving mainly short routes, fast charging is therefore assumed to be utilized by smaller share of vehicles compared to FCEV that likely will rely more on commercial large-scale filling stations.



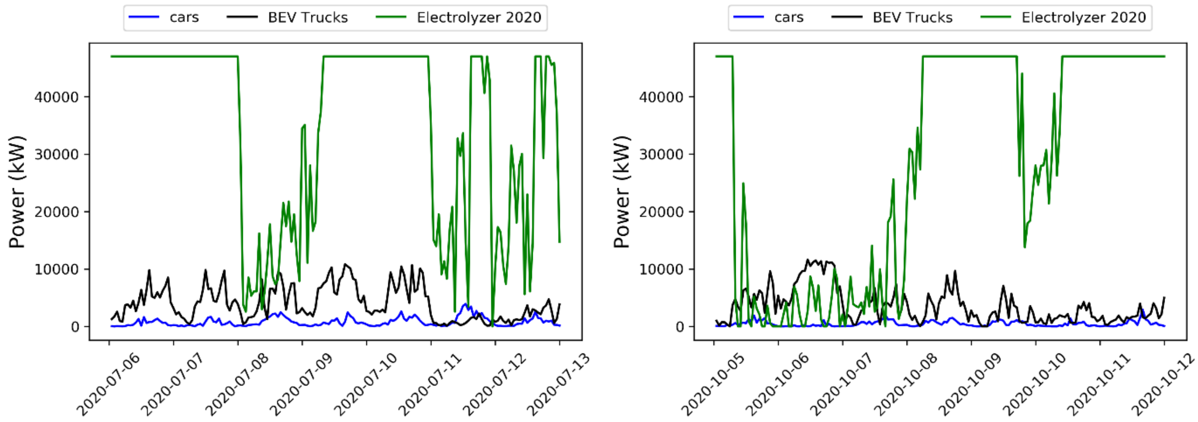


Figure 2. Electricity demand for the 75% BEV and 25% FCEV case during four weeks (Monday to Sunday) representing winter, spring, summer, and autumn.

3.2 PV production

Both the BEV and FCEV stations were initially optimized for the orientation (azimuth) and the tilt of the PV-system to determine which configuration that was most cost-efficient for the specific load patterns. Seven orientations (90, 120, 150, 180, 210, 240, 270), and six tilt angles (10, 20, 30, 40, 50, 60) were included. The results showed that south orientations with tilt angles of 30-50 were most cost-efficient. These results did not take snow shading into account, and for a proper analysis, snow coverage was modeled, and results comparing PV production with and without snow losses are presented in Figure 3. The total kWh/yr including snow losses (Figure 4) shows that there is an optimum in module tilt for this location in the range of 30 – 40°. The difference in kWh/year, comparing no snow losses with snow losses shows that the loss due to snow on the modules reduces as the tilt of the modules increases. This can be explained with that the snow slides off the panels easier when the tilt is higher. This is taken into account in the employed model.[17] Based on these results it was concluded to perform the main system simulations with south oriented modules with a tilt of 40°.

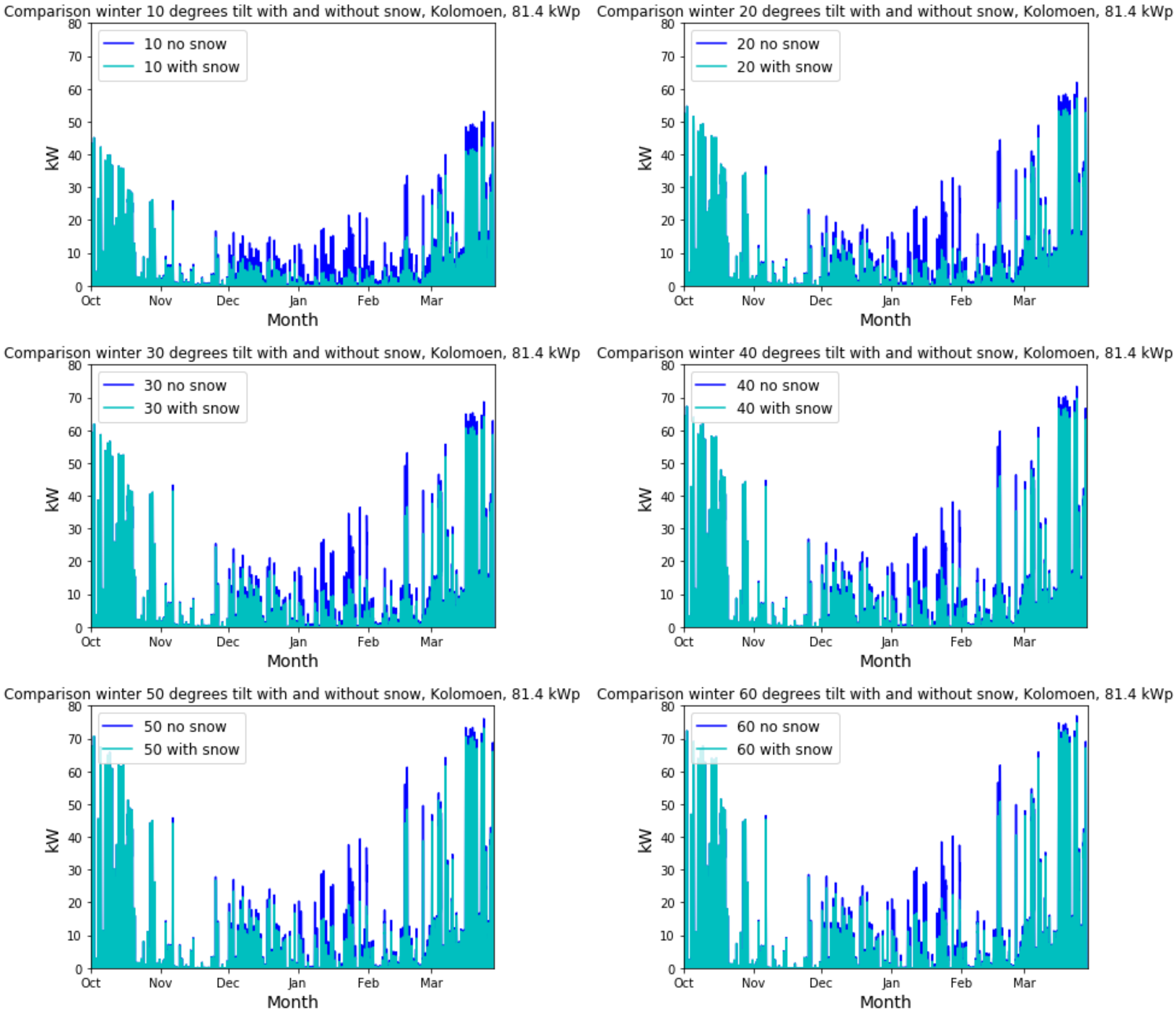


Figure 3. Plots showing modeled PV power output for different tilt angles (10°-60°) with and without snow loss modelling during winter months at the site north of Oslo, Norway.

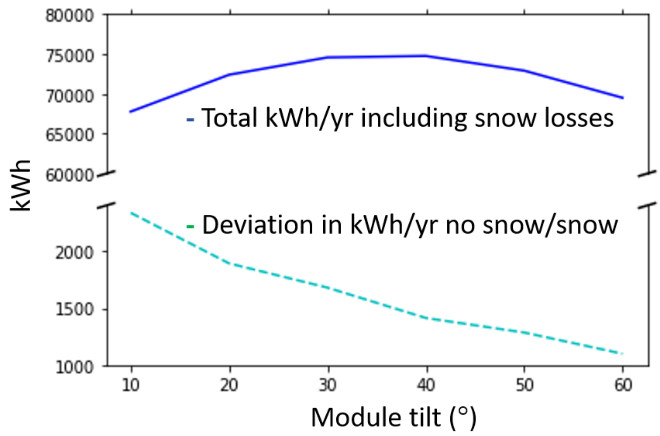


Figure 4. Plot showing the total generated energy per year, including snow losses, as a function of module tilt (full line), and, the difference in the total generated energy per year with no snow losses and with snow losses (dashed line).

3.3 Dimensioning and cost-efficiency of co-localization

Table 4-9 presents the results on the costs and the dimensioning of the PV-system for single (BEV and FCEV) and co-localized (BEV and FCEV) charging/filling stations. The main objective of this work was to determine if a co-localized station is more cost-effective than two single stations. Figure 5 summarizes the results of NPC calculations and show that the co-localized stations have 0.1-1.4% lower NPC depending on BEV/FCEV distribution and cost assumptions. For the 2020 cases, cost reductions with co-localization are clearly lower (0.1-0.2%), while the 2030 cases are more in line with previously reported results, despite representing a different system.[8] Cost-reductions increase with decreasing FCEV share, and the marginal reductions in NPC are related to more efficient utilization of produced PV-power. This is shown in Figure 7 where it is seen that PV export in a co-localized setting is reduced more for the cases with low FCEV share. Optimal PV-capacity for the 2030 cases did not increase with co-localization since installed capacity in single stations exceeded peak demand. For the 2020 cases (Figure 6), optimal PV-capacity for the co-localized station is 2-3 times the size of the two single stations. This is probably because of the more stable electricity demand in the co-localized station, that reduces export and allows for larger PV-system installations. PV export varied among the different cases, but for the 62.5% BEV and 37.5% FCEV case, co-localized led to a lower PV export despite a 120% larger PV-capacity. A calculation of PV-share utilization, i.e. the ratio of PV-production to total consumption, showed that co-localization (75% BEV and 25% FCEV) increased the share of PV from 2.2% to 6.2% for 2020 and from 16.9% to 18.4% for 2030. Integration of energy carriers in this manner has been proclaimed as an effective measure for increasing renewable energy in local grids, and these results support that claim. The 62.5% BEV and 37.5% FCEV case had the largest PV-installation at 67.5 MWp. For reference, a PV-park this size would require about 0.8 km^2 land area.[30] This system is expected to produce about 62 GWh yearly, which is about 2.5 times more than the work by Mourad et al. for a BEV station without hydrogen production.[4]

Table 4. Dimensioning and cost-efficiency of 62.5% BEV and 37.5% FCEV case with technology costs of year 2020.

	Unit	BEV	FCEV	Co-localized
NPC	EUR	36 520 888	274 209 742	310 446 776
PV size	kWp	2 840	3 917	14 876
Battery	kWh	0	0	0
Battery	kW	0	0	0
PV export	kWh	107 505	102 668	204 616

Table 5. Dimensioning and cost-efficiency of 75% BEV and 25% FCEV case with technology costs of year 2020.

	Unit	BEV	FCEV	Co-localized
NPC	EUR	42 716 896	185 147 427	227 543 856
PV size	kWp	3 020	2 833	16 165
Battery	kWh	0	0	0
Battery	kW	0	0	0
PV export	kWh	106 486	79 790	341 184

Table 6. Dimensioning and cost-efficiency of 87.5% BEV and 12.5% FCEV case with technology costs of year 2020.

	Unit	BEV	FCEV	Co-localized
NPC	EUR	48 917 769	91 707 753	140 333 798
PV size	kWp	3 167	1 333	13 536
Battery	kWh	0	0	0
Battery	kW	0	0	0
PV export	kWh	103 435	35 594	260 365

Table 7. Dimensioning and cost-efficiency of 62.5% BEV and 37.5% FCEV case with technology costs of year 2030.

	Unit	BEV	FCEV	Co-localized
NPC	EUR	38 922 275	284 029 683	321 221 316
PV size	kWp	12 503	55 000	67 503
Battery	kWh	5 571	0	8 560
Battery	kW	2 310	0	3 441
PV export	kWh	2 845 958	12 014 461	11 912 838

Table 8. Dimensioning and cost-efficiency of 75% BEV and 25% FCEV case with technology costs of year 2030.

	Unit	BEV	FCEV	Co-localized
NPC	EUR	45 657 637	189 627 036	233 249 279
PV size	kWp	14 461	37 000	51 494
Battery	kWh	5 015	0	7 277
Battery	kW	2 215	0	3 276
PV export	kWh	3 459 467	8 152 478	8 484 536

Table 9. Dimensioning and cost-efficiency of 87.5% BEV and 12.5% FCEV case with technology costs of year 2030.

	Unit	BEV	FCEV	Co-localized
NPC	EUR	52 399 907	95 247 428	145 650 516
PV size	kWp	16 482	19 000	35 486
Battery	kWh	6 548	0	7 902
Battery	kW	2 500	0	3 587
PV export	kWh	3 911 672	4 305 007	5 475 550

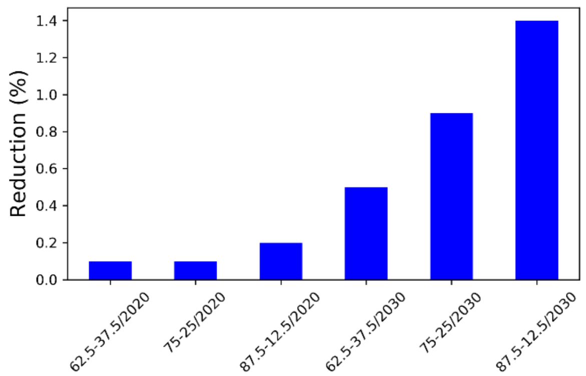


Figure 5. Reduction of NPC in co-localized station compared to single BEV and FCEV stations. X-axis represents the different cases (BEV/FCEV distribution and year for cost assumption).

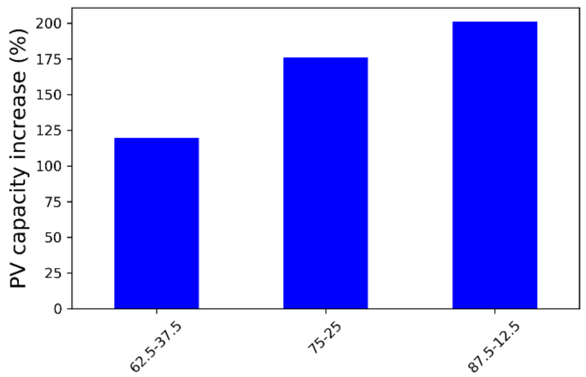


Figure 6. Increase in cost-optimal PV-capacity with co-localization of BEV and FCEV stations for the 2020-scenario. X-axis represents the different BEV/FCEV distribution cases.

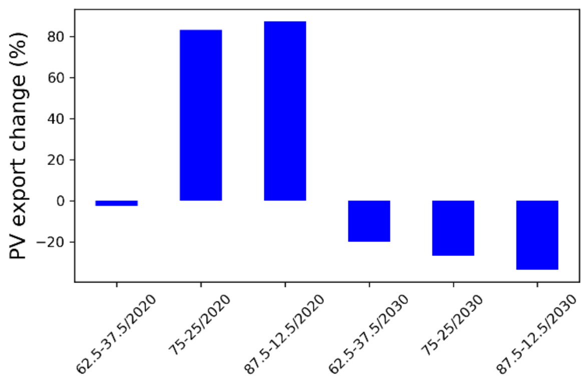


Figure 7. Change in PV export with co-localization of BEV and FCEV stations. X-axis represents the different cases (BEV/FCEV distribution and year for cost assumption).

All results presented above are based on PV-production profiles with snow losses included, and to determine the impact of system dimensioning and LCOE, one additional optimization was performed with PV-production data without snow losses for the same orientation and tilt. The results on optimal PV-capacity and LCOE for both cases are presented in Table 10. Neglecting snow losses results in 0.3-0.5% lower LCOE and over-dimensioning of PV-capacity with about 25% for the 75% BEV and 25% FCEV case in year 2020. Although the model used to determine snow losses was formulated based on roof-mounted systems, and more data from ground-mounted systems are needed to validate the model, these results indicate that accurate dimensioning of PV-systems in Nordic conditions should consider snow losses. Another important aspect of the results in Table 4-9 is that these are performed without considering degradation of the PV-modules. Degradation rates for crystalline silicon modules in Norway have been estimated to 0.1-0.19% per year.[31] Additional simulations were therefore performed to determine how a degradation rate of 0.2%/year would affect LCOE. Results from the co-localized station for the 75% BEV and 25% FCEV case showed that a degradation rate of 0.2% increased LCOE with around 0.1% (year 2020) and 0.5% (year 2030). Although only one case was analyzed, it is believed that similar results are to be expected for the other cases.

Table 10. Optimal PV-capacity and LCOE for the co-localized station (75% BEV and 25% FCEV) with and without snow losses in the PV-production data.

	With snow loss		Without snow loss	
Year	PV (kWp)	LCOE (EUR/kWh)	PV (kWp)	LCOE (EUR/kWh)
2020	16 165	0.0724	20 206	0.0722
2030	51 494	0.0796	51 494	0.0792

3.4 Load flexibility and battery optimization

The role of stationary batteries in the charging and filling stations were also investigated and the results showed that batteries were not cost-efficient in the 2020-scenario. In the 2030-scenario, however, both the BEV and the co-localized stations were found to include batteries. Obviously, the lower battery costs in 2030 contribute to cost-efficiency, but higher demand charges will also have a clear impact. For context, the demand charges (EUR/kW) used in these analyses are to the authors knowledge one of the highest in Norway, with winter months having an hourly rate of about 12 EUR/kW, and with the assumed yearly increase of 2%, demand charges rise to 14 EUR/kW in the 2030-scenario. Table 4-9 further shows that optimal battery size is rather insensitive to distribution of BEV/FCEV. The largest batteries were found in the co-localized stations, where energy capacities ranged between 7 300 and 8 600 kWh and C-rates ranged from 0.40 to 0.45. Previous work on PV-battery systems for buildings in Norway has shown that peak shaving stands for most of the savings from battery operation, not increased self-consumption or energy arbitrage.[32] The monthly peak shaving capacity in kW for the three different BEV/FCEV distributions in the co-localized station during 2030 are presented in Table 11. Power capacity of battery was 3 441 kW (62.5% BEV and 37.5% FCEV), 3 276 kW (75% BEV and 25% FCEV), and 3 587 kW (87.5% BEV and 12.5% FCEV). The cost-optimal battery power capacities vary slightly among the three cases, and this is due to different load demands at the co-localized stations and varying size of PV-system. However, despite these variations, it is interesting to note that the needed power capacity is about 3.5 MW for all cases when considering only behind-the-meter battery services. During March to September, peak shaving capacity is larger than battery converter capacity, meaning that the PV-system also contributes to reduced demand charges. The battery capacities found in this work are low in comparison to load demand and installed PV-capacity. In another study with significantly larger battery-to-PV-ratio (616 kWh battery and 445 kW PV), an energy management system was developed to benefit from energy arbitrage, and the authors concluded that benefits generated for the grid and society were larger than the economic benefits.[2] Since cost-efficiency of batteries is dependent on the peak shaving potential, it is obvious that the FCEV station, with a flat electricity consumption profile (figure 2) did not include batteries.

This analysis has not quantified profit generation from contribution to the electricity reserve markets, nor has a detailed analysis of the electricity price volatility been performed. The national TSO have published estimations indicating more volatility and higher electricity prices during winter months and lower during mid-day in summer months.[33] Such scenarios will impact the value of both PV and battery and require more detailed analyzes. Participation with batteries in the electricity market has shown promising results in the UK.[34] However, due to differences in local market conditions, and evolving market products, a similar study for the Norwegian context is needed. Batteries will probably also contribute to reduced grid-connection costs at large stations and should be analyzed more closely for specific cases since the costs depend on local conditions. It is expected that smart charging and batteries will contribute with significant flexibility in future energy systems and co-localized stations like the one described in this paper are at the core of such flexibility systems. [33] Besides flexibility from stationary batteries, it is believed that scheduling the operation of the electrolyzer by shifting the operation in time is a cost-efficient source of flexibility that could increase profitability further. The electricity demand profile of the FCEV station is flat with peak widths of one to multiple days (figure 2), so by reducing electricity input to the electrolyzer for an hour during high demand at EV-chargers, the total electricity demand could be clearly lowered. This requires forecasting the demand and state-of-charge of the hydrogen tank, and possibly also a larger hydrogen tank. Future work should therefore focus on introducing flexibility to the electrolyzer to perform peak shaving by demand side management and determine profitability in relation to the battery systems.

Table 11. Peak shaving by PV-battery system at the co-localized station for the different cases in 2030.

	62.5% BEV and 37.5% FCEV	75% BEV and 25% FCEV	87.5% BEV and 37.5% FCEV
Month	Reduction (kW)	Reduction (kW)	Reduction (kW)
1	2 969	2 972	3 420
2	3 176	3 066	3 137
3	3 915	3 828	4 017
4	4 282	4 359	4 459
5	4 169	3 854	3 722
6	7 529	7 536	8 446
7	4 848	4 362	4 150
8	4 302	4 139	4 370
9	4 301	3 413	3 331
10	2 114	2 185	2 284
11	3 241	3 238	3 404
12	2 675	2 886	3 213

This analysis focused on the cost-efficiency of power flows and did not include equipment costs for battery charging and hydrogen filling, nor is it an analysis of the total cost of ownership. The results presented in this paper aids as a guide towards dimensioning of PV-battery systems for electrification of the transport sector consisting of both battery-electric and hydrogen fuel cell vehicles.

4. Conclusion

Design and optimization of charging and filling stations for the electrification of light and heavy-duty vehicles in a major Norwegian road corridor were performed. Three different energy demand scenarios were studied to explore how distribution of battery electric and fuel cell electric vehicles impact design and cost-efficiency of charging/filling stations. The results indicate that co-localization of charging stations for battery electric vehicles and filling stations for hydrogen fuel cell vehicles can reduce net present cost by 0.1-1.4%. The clearest benefits were observed for a future case with more favorable cost-assumptions. Based on the marginal cost reduction, it is not obvious that co-localized stations are more cost-efficient than two single stations. However, co-localized stations enabled increased local renewable power utilization by increasing cost-optimal size of PV-system and/or reduced electricity exports. These results shall be seen as preliminary as there is no experience of utility-scale PV-parks in Norway and their connection to charging/filling stations. Results from optimization of PV-system showed that production losses related to snow shading at the site in Norway are important for accurate dimensioning. Stationary batteries were found to improve cost-efficiency further by performing peak shaving, but only for a future scenario with lower battery costs and higher electricity prices.

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