DRAFTING A HYDROGEN VISION FOR TASMANIA

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Abstract: Tasmania is currently deriving more than 90 percent of its electricity from renewable sources. To prevent drought risk effects the hydroelectricity-driven energy industry is expanding its capacity and diversifying its supply options with massive investments in wind projects, the introduction of natural gas, and the connection to the Australian electricity grid.
The paper investigates the potential benefits and barriers associated with a statewide hydrogen infrastructure in the 2005-2025 time frame. Specifically, opportunities for decreasing Tasmania's reliance on imported sources of energy and reducing greenhouse gas emissions. A multi-level analysis, combining tools and methods common to energy planning and modeling of energy systems, is here presented for four hydrogen demand scenarios each driven by different fuel-cell vehicles penetration rates, and five alternative infrastructure pathways.

1. Introduction

Tasmania is the only insular state of Australia. The population, currently estimated at 481200, has been growing steadily in the last decade and it is forecasted to either increase to around 495000 or decrease to 435000[1] by 2025 in three forecast scenarios recently released by the Australian Bureau of Statistics [1]. Tasmania’s economy, once reliant mainly on crops and with the extraction and exports of primary resources (forestry products such as saw-logs, woodchips and other) still playing a major role, is currently experiencing a boom driven by tourism and commercial activities. Other major economic activities are represented by energy-intensive industries such as aluminum and zinc smelting, pulp and paper milling and iron ore mining.
This set of conditions led historically to a unique pathway of energy infrastructure development focused on the supply of cheap and reliable electricity to attract foreign investors to the island: the hydroelectric infrastructure developed for these purposes represents over 90% of the current generation capacity. Other energy sources, with the exception of wood and part of the coal, are entirely imported in Tasmania representing a major negative voice of the State’s national and international trade balance.

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[1] The figures from the original ABS scenarios, released in 2001, have been normalized to the figure for the 2004 estimated residential population publicated on ABS website (the three original forecast figures were, for 2004, set respectively at 471400, 466200 and 462700)

In recent times there has been a growing interest in the development of a hydrogen-energy infrastructure in Tasmania. This vision is strongly supported by the electric generation company, Hydro Tasmania. The company has recently initiated an aggressive plan for wind power developments, with 450 MW additions in wind generation capacity by 2012. The production of hydrogen from wind power is a long-term goal of this strategy.

The establishment of an infrastructure for production, storage, transmission and distribution of renewable hydrogen carries the promise to augment storage capability of the Tasmanian electric system and extend the use of renewable resources to the State transportation fleets.

Tasmania offers unique conditions as a test-bed for hydrogen energy technologies and systems: a real-world transportation and energy infrastructure, akin to the standards of present developed countries, combines with other peculiar advantages: among them the longest driving distance between two major urban centers being only 200 km (from the capital city, Hobart, to the second largest centre, Launceston). In this context the importance of fuel autonomy as a barrier to the large-scale introduction of the current generation of hydrogen vehicles is thus sensibly reduced. On the policy side, Tasmania, being an independent state, enjoys full authority over standards and regulation and the Tasmanian Government has already committed to work closely with the major stakeholders in order to ease and quicken the release of standards for hydrogen energy systems, following a well-oiled co-operative scheme unique to the Tasmanian policy development process. Personal motor vehicle insurance, not being a mandatory requirement in Tasmania, represents an important advantage in dealing with an issue that is a major economic barriers in the introduction of new vehicle technologies [2]. To these conditions is worth adding the role Tasmania plays as the chief sea link for Australian Antarctic operations and as host to various International Antarctic Organizations: the perspective of Tasmania "fueling" cleaner Antarctica expeditions adds iconic value to what can be truly considered as being the *Iceland of the Southern Hemisphere*.

2. Overview of the Tasmanian energy economy

Primary energy

Tasmania primary energy supply has been over the 90 PJ quota since the late 1990s. Total Primary Energy Supply (TPES), reached 95.7 PJ during the fiscal year 2001-02[2]. The industrial sector accounted in the same year for a share close to 50%.

Table 1 - Primary energy supply in Tasmania 2000-01, by sector[2]

	Agriculture	Industry	Transport	Commercial	Residential	Energy Sectors	Total
PJ	2.3	46.0	23.0	6.6	13.7	4.0	**95.6**
Share	2.4%	48.1%	24.1%	6.9%	14.3%	4.2%	**100%**

The primary energy sources fueling Tasmania's economy are:

Hydro, supplying over 90% of the generated electricity.

Oil, supplying the entire demand for transportation energy and covering important shares of the demand for residential and commercial energy (respectively 4.38% and 20.21% in 2000-01) for cooking, space and water heating end-uses. Fuel oil was also used up to 2003 in the Bell Bay back-up thermal power station (240 MW), recently converted to natural gas.

Wood, still covering a significant share of energy use for space and water heating services in the residential sector (56.57% in 2000-01[3]), is used as a secondary fuel in the pulp and paper,

[2] All the Australian Statistics are referred to the fiscal year beginning July 1st. In the remainder of the document each year will be referred to using the solar year that includes the second half of the fiscal year: e.g. 2004 will be used to represent fiscal year 2003-04.

food, beverages and tobacco industries (wood represented 7.81% of energy consumption in the industrial sector in 2000-01).
Coal, employed mainly in the Iron, Cement and Pulp and Paper industries and accounting for 23.71% of total energy consumption in the industrial sector.
Natural Gas, introduced between 2002 and 2004 with the construction of a pipeline across Bass Strait, built by Duke Energy. The project comprises of 753 km of undersea and underground pipeline and is rated at an import capacity of 42-50 PJ/year[4].
The chart shows the evolution of primary energy supply in Tasmania for the period 1973-2001. The latest peak in the chart, driven by the increased consumption of oil in the back-up thermal power station of Bell Bay, corresponds to a severe drought in the 1988-1991 period.

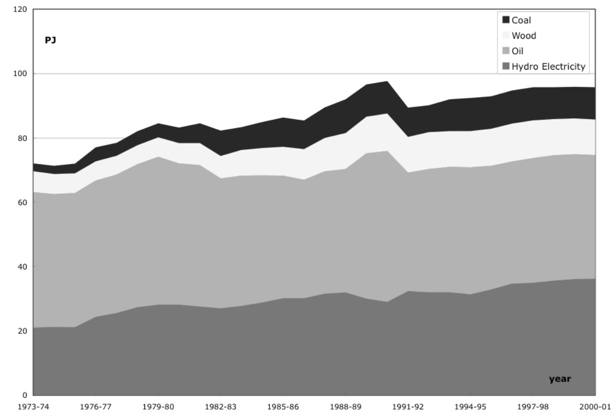

Figure 1 - Primary energy supply in Tasmania 1973-2001, by source[5]

Tasmania electricity system
After the commissioning of the first state-owned hydroelectric power plant, in 1914, the capacity installed grew constantly, with two waves of significant additions in the 50s and 60s. The availability of cheap and abundant electricity attracted several energy intensive industries to the State, an aluminum smelter, a zinc and copper smelter and a pulp and paper mill among others, which in turn raised the demand for electricity to unprecedented levels. In order to meet this industry-driven demand and to avoid supply constraints during drought periods the Hydro Electric Corporation (HEC) was stimulated in the late 1960s to plan new hydroelectric developments and a back-up oil-fired steam power plant (Bell Bay 240 MW). The last major development, the Gordon-Pedder scheme (432 MW), was originated from the flooding of the original Lake Pedder and the creation of a new lake on the bed of the Gordon River. This scheme and its proposed twin, the Franklin below Gordon, were objects of growing concerns raised from the Green Party, in its very first appearance on the world scene at a meeting in Hobart, the capital of Tasmania, in 1972. The protests led the Federal Government of Australia to promulgate the *World Heritage Properties Conservation Act*, in 1983. The Act declared over 40% of land area in Tasmania, comprising mainly of rainforests concentrated in the South West, protected [5]. This posed an end to Tasmania's era of hydro industrialization, with only two minor dam developments built between the 1986 and 1994.

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[3] These high figures are to be imputed to the poor conversion efficiencies, and energy contents, associated with wood. The share figures in terms of energy services are about 50% lower. Nevertheless energy consumption figures give the idea of the still high extent of wood use.

[4] The value is reported differently in diverse sources, all remaining in the 42-50 PJ range, with [3] reporting the highest value.

[5] Constructed from ABARE original data [4].

The Tasmanian Electricity Sector is presently undergoing a restructuring process started with the vertical disaggregation of the Hydro Electric Corporation (HEC) into a generation, a transmission and a distribution/retailing company on July 1st, 1998. It will be completed with the commissioning of the undersea DC connection to the Australian mainland, named *Basslink* (rated at respectively 300 MW of import and 660 MW of export capacity), scheduled for November 2005, and the entry of Tasmania into the Australian Electricity Market.
The Tasmanian power generation system comprises currently 31 power stations of which 29 hydro electric, the other two being Woolnorth wind farm and Bell Bay thermal power station. The combined hydro capacity on mainland Tasmania is currently 2263.7 MW subdivided into six catchments. Hydro Tasmania estimates the system storage capacity at 14389 GWh.

Table 2 - Generation capacity and water storage in Tasmanian hydro catchments[6]

Catchment		Great Lake South Esk	Gordon Pedder	Derwent	Mersey Forth	King Yolande	Pieman Anthony	TOTAL
no. of power plants		3	1	10	8	2	4	**28**
installed capacity	**MW**	381.6	432	494.6	309.1	92.4	475	**2263.7**
energy in storage	**GWh**	7361	4699	1800	160	176	186	**14389**

Total electricity supplied by the Tasmanian power system is currently around 10100 GWh per year, with about half of this being consumed by the four biggest industrial customers. System load is highly seasonal, with daily peaks varying from around 1300 MW in mid-summer to nearly 1700 MW in mid-winter, due to the high penetration of electric heating systems [6].

Wind developments

Tasmania enjoys a world-class wind resource resulting from its geographical location. The island is placed between the *roaring forties*, the areas between latitudes 40° and 50° south, where strong prevailing winds blow from the west throughout the year [7]. The chart below shows the monthly long-term mean wind speed for Tasmania being in the 8.5-10 m/s range.

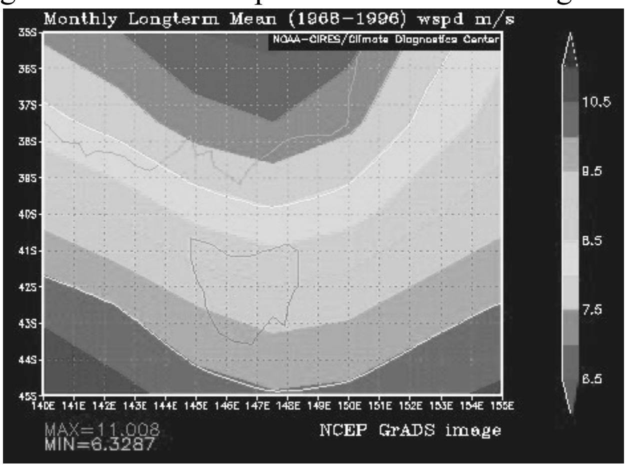

Figure 2 - Monthly long-term mean wind speed chart, Tasmania region 1968-1996[7]

Hydro Tasmania started measuring wind velocity in various sites as early as 1980 and initiated recently an aggressive plan for the development of wind power projects. The plan started with the commissioning in 2002 of the Woolnorth Wind Farm in north-westernmost Tasmania. Stage 1 (10.5 MW comprising 6 Vestas V66 turbines) 31 more turbines (stage 2 for total 54.25 MW) have been added in May 2004. The project will be completed with

[6] Elaborated from Hydro Tasmania original data [6]

[7] Source CDC-NOAA [8]

additional 37 turbines (stage 3, planned for 2008). Two other wind farms are planned to be commissioned by 2012: Heemskirk (on the west coast, 160 MW) and Musselroe (on the north-easternmost area of the island, 140 MW) both in advanced stages of approval [6].

Natural Gas industry
The Natural Gas infrastructure is currently rolled-out to Tasmanian customers. After the completion of the transmission pipeline, built by Duke Energy, in early 2003 and the connection of Bell-Bay power station and of the major industrial users located along the Tasmanian pipeline, the New Zealand-based utility company PowerCo started to build the backbone distribution network. In late 2003 the two licensed gas retailers, OptionOne (owned by PowerCo) and AuroraEnergy (the only electricity retailer in Tasmania), started to connect commercial and residential customers. The rollout process should be completed by late 2007. A fast penetration of natural gas over the uses previously fueled by means of oil products, is expected, while the much more interesting *fuel switching* from electricity to natural gas for cooking, space and water heating end-use services, envisaged as the major benefit of the introduction of natural gas, has to face the inertia represented by the large number of electric appliances covering these end-uses in the Tasmanian market.

3. Drivers for a Tasmanian-based hydrogen economy

Reduction of oil dependence
Oil products supply the entire final energy demand of the Tasmanian transportation sector. No refining infrastructure is present in Tasmania and the island is a net importer of oil derivatives from refineries located in south-eastern Australian States (New South Wales, Victoria and South Australia). Figures for 2001 on consumption of petroleum products for energy uses in Tasmania are given in the table below.

Table 3 - Consumption of petroleum products for energy use Tasmania, 2001

LPG	Automotive Gasoline	Automotive Diesel	Automotive Diesel	Jet kerosene	Aviation Gasoline	Industrial Diesel	Fuel Oil
10^6 litres							
59	130	319	292	31	2	1	74

Road transportation alone accounted for 20.72 of the total 35.12 PJ of petroleum products consumed (for both energy and non-energy uses) in Tasmania in 2001 [4].
Tasmania could benefit from the introduction of hydrogen vehicles both in terms of enhanced self-sufficiency of energy supply and significantly reduced transportation related emissions of greenhouse gases and criteria pollutants.

Drought risk
Tasmania's large reliance on hydroelectricity translates into a weakness of the system under severe drought conditions. The system energy equivalent at full storage, totaling 14389 GWh is roughly equivalent to 16-17 months at the current level of electricity consumption in Tasmania [6]. Storage figures alone, however, are not sufficient to assess the energy yield of a hydroelectric scheme, due to the combined presence of both reservoir and run-of-river power plants. Hydro Tasmania assesses the long-term capability of the hydro system being at 1164 MW average or 10200 GWh/y.
It is evident, however, how persistent drought periods and the subsequent increased reliance on storage schemes, in order to generate the required electric power, could lead to a continuous decrease of water levels in the storages. Tasmania experienced various drought

periods, the last of which between 1988 and 1991 led to the decision to run the back-up thermal generator, Bell Bay, as a base load power plant. Another drought period is likely to have peaked in Tasmania during the summer month of December 2002. This caused the storage level of the whole system to fall below 30%, and again Bell-Bay has been run as a base-load plant in order to allow the major lakes and basins to regenerate their storage capacity. The extensive use of Bell-Bay power station results directly into an increase in generation costs and in greenhouse and criteria pollutant emissions from the Tasmanian electric sector. The chart below shows the trend of storage energy equivalent in Tasmania hydroelectric catchments for the period 1997-2004.

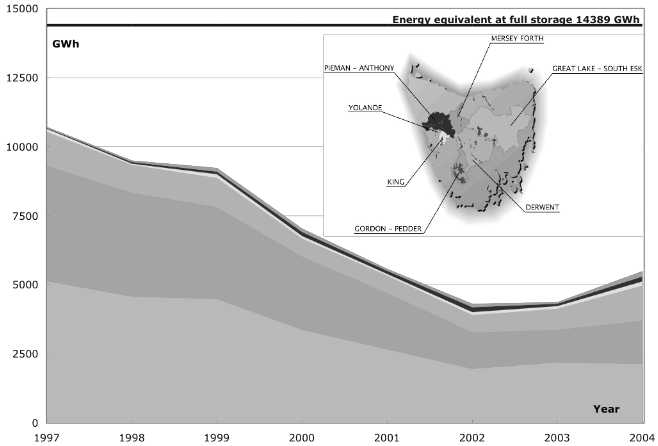

Figure 3 - Energy equivalent of storage in Tasmanian hydroelectric reservoirs, 1997-2004[8]

The large scale production of hydrogen – from wind energy during off-peak electric demand periods and from hydroelectricity when dam spills are necessary to avoid storage overflowing – could contribute to diversify and augment storage options for the whole electric system. An investigation of this option, requiring a detailed analysis of time series of electricity demand, wind energy generated and water levels in the storage, is left to further research activities: in particular will be analyzed the opportunities for the reduction of the impact of drought periods that could arise by generating part of the electricity required from the stored hydrogen.

Grid management issues

In its full development, wind power will account for more than 20% of the available generation capacity on the Tasmanian mainland. Intermittency of wind generation is likely to impact the management of the grid, especially during peak demand times, with the system close to its dispatchment limits, and off-peak times when wind power could be supplying the majority of the energy flowing into the grid. Hydrogen production during off-peak times allows for a better management of the wind power flowing into the system, and the same hydrogen could be employed to generate back electricity during peak demand times.

Enhancing electricity and fuel supply for minor island communities

Energy needs of minor island communities in the Bass Strait are currently met by hybrid diesel-wind systems operated by Hydro Tasmania, and rely also on the shipment of oil products for transportation and thermal comfort purposes. Hydro Tasmania is currently exploring opportunities for the development of hybrid wind-diesel-hydrogen systems and recently received a grant for a pilot plant of this kind to be installed in Cape Barren Island, the third by extension of the Bass Strait Islands.

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[8]Elaborated from Hydro Tasmania original data [6], water level recorded at July 1st each year

Fueling Antarctica
Tasmania, Hobart in particular, serves as Australia's chief sea link to the Antarctic and South Pacific, with the Australian Antarctic Division located in Kingston. Hobart is the homeport of the Australian Antarctic flagship *Aurora Australis* and the French ship *l'Astrolabe, which* makes regular supply-runs to the French Southern Territories near and in Antarctica.
The Australian Antarctic Division maintains four permanent research stations: Mawson, Davis and Casey on the Antarctic mainland, and Macquarie Island in the sub Antarctic territories. Scientists and support staff occupy all four stations year-round.
All Antarctic operations (electric generation and vehicles) employ a diesel blend called SAB (Special Antarctic Blend: LHV 43.82 MJ/kg; Density 805 kg/m^3; Sulfur content 0.05 wt.%) specifically designed to avoid freezing. The cumulative capacity of the diesel generation systems in the Australian Antarctic bases including main and emergency power generators is 3.06 MW (respectively 2.1 and 0.96 MW) [9].
While hydrogen could be seen as an alternative solution for the storage of wind energy, another equally attractive application could be its ability to provide fuel for the ground and air transportation services, and perhaps to the regular service Antarctic ships, with a sensible reduction in the emission of greenhouse gases and criteria pollutant emissions. This will surely benefit the precious and fragile Antarctic ecosystem[9].

5. Modeling methodology

The modeling of hydrogen scenarios in this study is performed combining tools and methods derived from Energy Planning, Energy Systems and GIS-based modeling of the Tasmanian Energy and Transportation infrastructure. The intent is to analyze the impacts associated with the development of a hydrogen energy infrastructure in the context of the wider Tasmanian energy system. A LEAP™-based [10] model of the Tasmanian energy infrastructure is adopted as the top-level modeling tool. The model, *TasmaniaH2Pathways* is the evolution of a set of models originally developed for the Tasmanian Office of Energy Planning and Conservation as an integrated modeling tool for integrated resource planning and energy policy advising by one of the authors [11,12]. Capital and operating costs and the average yearly capacity factors of the Tasmanian operating and proposed wind farms have been evaluated by means of detailed models of each wind project based on the RETscreen® software package [13]. A GIS-based model of the Tasmanian energy and transportation infrastructure has been used for the evaluation of traveling distances and the extension of pipeline branches.
LEAP™ is an energy-environment accounting software tool in which energy, environmental and monetary costs of several demand-side and supply-side options, can be evaluated based on bottom-up energy demand forecasts. The advantages of bottom-up approaches in forecasts of energy demand have been mentioned in a large number of scientific papers and texts, in particular [14,15]. They can be summarized into a better understanding of the physical structure of the energy demand and supply sectors and the transparency of modeling assumptions. These characteristics are key advantages in scenario and sensitivity analysis applications. The general formulation of the bottom-up energy modeling approach is:

$$Energy\_use = \sum_i Q_i \cdot I_i; \qquad [J] \tag{1}$$

[9] These issues will be addressed in detail in further research activities

That, given $Q_i = N_i \cdot P_i \cdot M_i$. can be described as:

$$Energy\_use = \sum_i N_i \cdot P_i \cdot M_i \cdot I_i; \tag{2}$$

With:

N_i	Number of customers eligible for the end-use *i*
P_i	Penetration of end-use service *i* (or of the end-use technology providing it)
M_i	Magnitude or extent of use of end-use service *i*
Q_i	Quantity of energy service *i*
I_i	Intensity of energy use for energy service *i*

In order to analyze economic costs and environmental impacts associated with a particular energy end-use *i*, the following parameters have to be multiplied to the ones above described:

C_i	Cost factors associated with the provision of the energy service *i*
EF_i	Emission factors associated with the provision of the energy service *i*

Different model designs can be associated with these basic formulae by varying the definition of the listed parameters and by adopting, for each of them, different levels of aggregation (by fuel, end-use technology, class of customers, etc.).

Depending on the measurement unit considered for a particular energy service the parameters in (1) and (2) will be defined accordingly. As an example the bottom-up analysis for a particular class of vehicles could be performed defining:

For N_i the number of vehicles in the class *i* (e.g. number of Light Duty Vehicles, LDVs);

For P_i the penetration of a particular engine technology in the class *i* (e.g. diesel engines);

For M_i the number of km traveled per year by vehicles in the class *i*

For I_i the average energy consumed per km traveled (i.e. 1/fuel economy) by these vehicles.

Considering yearly intervals the (2) becomes then:

$$Energy\_use_{LDV,Diesel} = vehicles_{LDV} \cdot \frac{vehicles_{LDV,Diesel}}{vehicles_{LDV}} \cdot \left(\frac{km}{vehicle \cdot year}\right)_{LDV} \cdot \left(\frac{MJ}{km}\right)_{LDV,Diesel}; \quad \left[\frac{MJ}{year}\right] \tag{3}$$

The emissions can be then calculated multiplying the terms in (3) to an *energy-based* emission factor (g/MJ), a method commonly used for greenhouse gases. In evaluating emissions of criteria pollutants, *distance based* emission factors (g/km) are usually defined. Total emissions can be obtained on multiplying these emission factors to the first three terms on the RHS of (3). Analogous considerations apply in the evaluation of the monetary costs, where factors for capital, fuel and other fixed and variable costs are introduced.

It is thus evident the major advantage of this modeling approach: the ability of evaluating energy consumption and environmental impacts across sectors while maintaining a clear focus on their social, economical and technological structures.

The adoption of projected values obtained from other studies or interpolated from historical data series or simply modeling assumptions for each of the parameters in (2) makes this methodology well suited for both forecasting and exploratory scenario analysis.

This modeling approach is further enhanced by some of LEAP^{TM} key characteristics: the modeler is provided with an integrated tool inclusive of an extensive database of technologies and environmental impacts and allows the analysis of several supply-side and primary resource alternatives through algorithms for dispatchment and capacity building options.

The version of *TasmaniaH2Pathways* model employed here for analysis presents three alternative pathways to hydrogen production: distributed generation at refueling station sites and centralized generation at demand centers (city gates) or wind farm sites. For the latter two, two alternative infrastructure options have been explored for the transmission of the produced hydrogen to refueling stations: gaseous hydrogen delivery through pipeline or tube trailer trucks, bringing the total of alternative infrastructures scoped to five. The evolution of the demand for hydrogen is performed through four exploratory scenarios for the penetration of hydrogen vehicles in the Tasmanian market. For each of the hydrogen demand scenarios the evaluation of the five alternative routes to the development of a Tasmanian hydrogen infrastructure is performed separately on the basis of projected costs, primary energy consumption and avoided greenhouse gas emissions. Scoping of pathways as competitor solutions and the design of hydrogen infrastructure development strategies, based on *least-cost* mix of technological options, are explored in other research activities [16,17].

6. Hydrogen demand scenarios

This study analyzes the impacts of four different profiles of market penetration of hydrogen light duty vehicles. Each of the four scenarios assumes hydrogen-fueled Light Duty Vehicles (LDV[10]) to gain a 10, 25, 50 and 100% share of the total LDV sales by 2025.

The profile of penetration of hydrogen vehicle sales over projected LDV sales in Tasmania is simulated to follow a logistic trend interpolated from the values reported in the table:

Table 4 - Analyzed scenarios for sales of hydrogen vehicles penetration in the LDV market

Hydrogen vehicle sales penetration scenarios *(H2LDVsales/TotalLDVsales)*					
year	**2005**	**2010**	**2015**	**2020**	**2025**
H2LDV-10	0%	0.7%	3.5%	7%	10%
H2LDV-25	0%	1.8%	9%	18%	25%
H2LDV-50	0%	3.5%	18%	35%	50%
H2LDV-100	0%	7%	25%	50%	100%

The penetration profiles for hydrogen vehicles presented here are in certain accordance[11] with values adopted in [18] for hydrogen LDV market penetration shares. The analysis is further enhanced in this study using a detailed stock turnover-modeling feature. This includes detail of stock vintage, projected sales and vehicle survival profiles peculiar to the Tasmanian vehicle fleets derived from [19,20], allowing for a reasonable evaluation of the inertia the characteristics of existing fleets represent as opposed to a *vehicle technology switch*. A detailed explanation of the methodology is presented in [11,12]. The four demand scenarios analyzed translate respectively into a stock of 20896, 53416, 105189 and 158603 hydrogen vehicles on Tasmanian roads by 2025. The hydrogen vehicle technology here considered is fuel cell hybrid-electric vehicles (FCHV). In the model the average fuel economy of new hydrogen vehicles is assumed to evolve from 55 in 2005 to 60 by 2015 and 65 mpgge[12] by 2025. The choice of Light Duty Vehicles as the only end-use hydrogen technology analyzed is arbitrary, however their dominance in the Tasmanian road vehicle fleet allows for a rough estimation of the size of a future hydrogen market for transportation in Tasmania. Passenger Cars and Light Commercial vehicles represented, at the end of October 2003, respectively 73.12% and 19.39% of the total 338484 vehicles on the road in Tasmania [19].

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[10] Light Duty Vehicle include the Passenger Cars and Light Commercial Vehicles categories of the Tasmanian Motor Register

[11] The study mentioned assumes a 15 years time horizon and assumes for the first year the values here adopted for the fifth year (2010)

[12] miles per gallon gasoline equivalent, the average fuel economy of new models of the other traditional vehicle technologies is assumed to grow 5% every 5 years

7. Scoped hydrogen pathways

The rich endowment of hydroelectric resources and world-class wind potentials helps Tasmania move towards a hydrogen-energy infrastructure reliant on renewable energy sources. Natural gas, introduced in 2003, is imported in Tasmania and its employment as a hydrogen source is likely to offset the benefits in terms of enhanced self-reliance of supply in the transportation sector (presently met by imports of oil derivatives) and to diminish the extent of reduction in transport-related greenhouse gases and criteria pollutants emissions. An indirect natural gas contribution to hydrogen production could be represented by the quota of electricity that will be displaced by natural gas end-use technologies penetration, in particular the quotas currently employed for the provision of cooking, water and space heating services in the residential and commercial&services sectors. The amount of electricity the *fuel-switching* process could make available represents an additional resource for electrolytic hydrogen production that does not require additions to electricity generation capacity. The three hydrogen infrastructure pathways explored in this study are the ones depicted in the figure below:

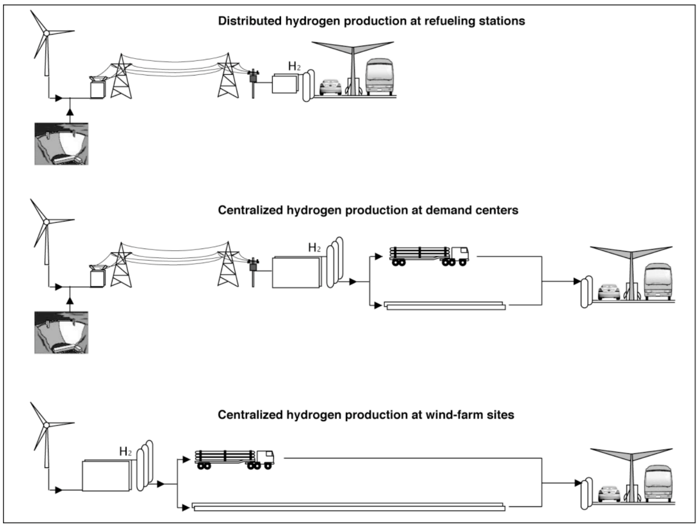

Figure 4 - Proposed hydrogen infrastructure pathways for Tasmania

Distributed hydrogen production at refueling stations

The simplest pathway is here scoped the first, with hydrogen produced directly at the refueling station sites. This solution combines the advantage of flexibility in both location and feedstock electricity, which, depending on grid management and dispatch strategies, will be derived either from hydro or wind power plants[13]. The distributed electrolyzer refueling station modules in the model are based on performance and cost figures of the Stuart Energy Stations featuring IMET-1000 serie electrolyzers [21], whose characteristics are listed below:

Table 5 - Cost and operational data for IMET-1000 series Stuart Energy Stations[14]

Model	H2 production capacity	Power consumption (incl. aux)	Max outlet pressure	Storage Capacity (at 42 MPa)	Capital costs (incl. aux. and balance of plant)
	Nm^3/h	kWh/Nm^3	bar	kg	$AUSD_{2004}/kW_{H2}$
SESf15	15	4.8	25	60	13,500
SESf30	30	4.8	25	120	9,400
SESf60	60	4.8	25	240	7350

[13] The contribution of the natural gas-fired bell Bay power station is here considered negligible due to its back-up operational characteristics.

Cost data, based on a recent offer made by Stuart Energy to Hydro Tasmania [22], refer to bulk purchases of more than 10 units. The capacity of distributed hydrogen production is fixed in 0.48 t_{H2}/day (roughly 4 times the SESf60 capacity) for ease of comparison with other studies [23]. For this pathway this is the size of new additions, i.e. the discrete hydrogen production capacity that the model is allowed to factor in, based on the projected growth of hydrogen demand. The storage at the refueling station site is assumed to be worth two days of hydrogen production (960 kg). Cost data used in the model is interpolated from the original disaggregated data and is estimated, for production units with capacities between 0.4 and 0.6 t_{H2}/day, being at 5000 AUSD[15] per kW of hydrogen production capacity. The table below reports the operational and cost data used in the model for the distributed production pathway.

Table 6 - Summary of modeling assumptions for distributed electrolysis at refueling stations

Production capacity t_{H2}/day	**Electrolyser consumption kWh/kg_{H2}**	**Auxiliaries consumption kWh/kg_{H2}**	**Storage (at 48.26 MPa) kg**	**Dispensing pressure MPa**	**Capacity Factor**
0.48	50.12	7.16	960	34.5	70%
Capital cost data			**Interest rate**	**Annual O&M costs**	**Lifetime years**
Electrolyzer AUSD$_{2004}$/kW$_{H2}$	**Total Aux. AUSD$_{2004}$/kW$_{H2}$**	**TOTAL AUSD$_{2004}$/kW$_{H2}$**			
3200	1800	**5000**	10.83%	5% of annual capital charge	20

Centralized production at demand centers

This pathway involves the production of hydrogen at major demand centers. The production facilities are considered to be located at the ports of the major urban centers: Hobart, Launceston, Burnie and Devonport. These locations result practical being virtually enclosed in the cities and offering clear economic advantages in terms of lower land lease prices and/or purchase costs. Moreover, their selection could turn useful for the provision of hydrogen to alternative end-uses (water transport vessels and special purpose vehicles such as fork-lifts). These diverse options could help justify the capital investments required by increasing the volume of hydrogen demand in the early stages of hydrogen vehicles penetration[16]. The size of each production unit is fixed at 24 t_{H2}/day. Each plant includes a centralized compressor and storage facility, with two days worth of production storage at the central plant (48 t of storage per each production unit). The choice of this capacity size is significantly lower than the values in the 150-600 t_{H2}/day range commonly adopted [18,23] for centralized hydrogen production units. This appears however the most appropriate capacity addition size for a market relatively small as Tasmania. Operational data for centralized production are based on the bipolar electrolyzers of the Atmospheric Series 5040 (1 t_{H2}/day) produced by Norsk Hydro. Cost data are scaled from the ones reported in [24] assuming a 0.9 scale factor.

Centralized production at wind-farm sites

In this pathway the hydrogen is produced in centralized electrolysis units installed in proximity of wind-farm sites. In modeling this option it is assumed that the plants are operated exclusively on power generated by the wind turbines. This modeling choice is made to stress the suitability of current and proposed wind generation capacity in Tasmania to support a future demand for hydrogen without affecting the electricity supply infrastructure. Particular attention is paid to the eventual increase of greenhouse gas emissions from the Tasmanian electricity sector associated with an eventually increased use of Bell Bay Power

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[14] Cost data are here reported as lumped figures (including electrolyser unit, auxiliaries and balance of plant costs) specific to kW of hydrogen production capacity due to confidentiality reasons.

[15] Australian Dollars

[16] The analysis of these options is beyond the scope of this work and will be carried in further research activities.

Station. Given the remote location of Heemskirk wind farm it is assumed that it will be simply connected to the electric grid and that the centralized production facilities will be sited in the proximity of Woolnorth and Musselroe wind-farms. The size of each production unit is fixed in 48 t_{H2}/day. Each plant includes a centralized compression and storage facility, with 96 t of storage per each production unit. These production units are based on the same Norsk Hydro bipolar technology described for the previous pathway.
For both centralized production pathway it is assumed that the central compressor station, feeding alternatively the central storage and the pipeline or the central storage and the trucks, maintains the same operational and cost figures. The table below reports a summary of assumptions for the two centralized production pathways.

Table 7 - Summary of modeling assumptions for centralized hydrogen production pathways

Pathway	Production capacity t_{H2}/day	Electrolyser consumption kWh/kg_{H2}	Auxiliaries consumption kWh/kg_{H2}	Storage (at 20 MPa) t	Lifetime years	Capacity Factor
Centralized at Demand Centres	24	49.56	4.16	48	30	90%
Centralized at Wind Farm sites	48		3.76	96		
	Capital cost data					
Pathway	Electrolyzer $AUSD_{2004}/kW_{H2}$	Aux. Total	TOTAL $AUSD_{2004}/kW_{H2}$	Electricity cost AUSD/MWh	Interest rate	Annual O&M costs
Centralized at Demand Centres	1200	1300	**2500**	6.0	10.83%	4% of annual capital charge
Centralized at Wind Farm sites	1000	1000	**2000**	4.5		

Transportation options for centralized production pathways

Two options are here scoped for the transportation of the hydrogen produced at centralized electrolysis units: delivery of compressed hydrogen gas through pipeline or tube trailer trucks. The figure shows the extension of the Tasmanian road network and of the recently completed Tasmanian natural gas pipeline along with the location of the operating and proposed wind farms.

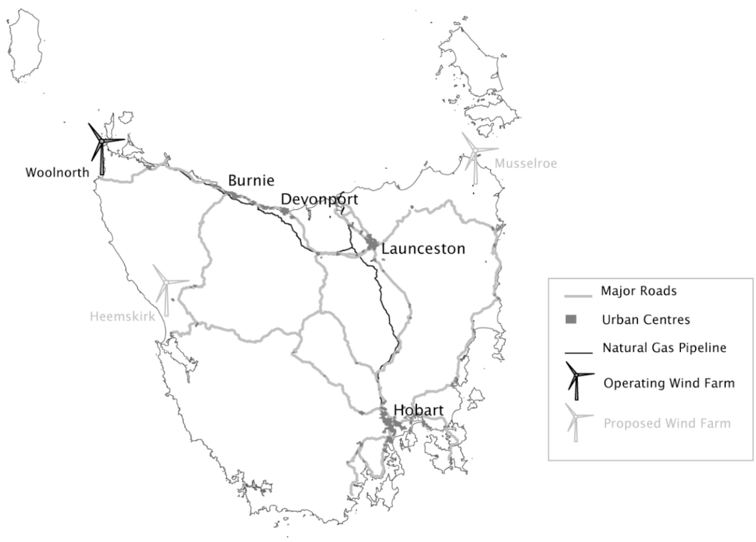

Figure 5 - Major urban centers, roads, gas pipeline route and wind farm sites, Tasmania

The onshore Tasmanian natural gas pipeline network is comprised of three main branches for a total of 473 km: the "intake" branch (21 km) between Five Mile Bluff, on the northern Tasmanian shore in proximity of the Bell Bay thermal power station, and Rosevale, at the outskirts of Launceston; the northern pipeline extension, from Rosevale to Port Latta (241 km), serving the centers of Burnie and Devonport; and the southern pipeline extension, from Rosevale to Bridgewater, at the outskirts of the capital city Hobart (168 km).

To these 430 km of Tasmanian onshore pipeline are to be added 305 km of undersea pipeline across Bass Strait and 27 km of onshore pipeline in Victoria, from Longford to the coast. Total cost of the project, offshore and onshore sections plus the conversion to natural gas of the Bell Bay power station was of 440 million AUSD. The Tasmanian onshore section represents around 35% of the overall pipeline capital costs [24]. For the scope of this study an eventual compressed hydrogen pipeline development is simply assumed to develop along the existing gas pipeline route.

Following a similar approach to the one described in [26], the cost of natural gas pipeline development is assumed to be highly representative of the cost of hydrogen pipelines. In this study we assume a lumped capital cost value of 330,000 AUSD/km for a pipeline at rated capacity of 350 t_{H2}/day. It is assumed this value includes also the capital costs associated with the development of distribution branches connecting the refueling station sites. The table below reports the modeling assumptions for operational and cost parameters of the pipeline modules.

Table 8 - Summary of modeling assumption for pipeline modules

Pathway	Pipeline flow t_{H2}/day	Max pressure MPa	Min Pressure MPa	Extension km	Capacity Factor
Centralized at Demand Centres	350	6.81	1.41	409	98%
Centralized at Wind Farm sites				542	
Capital cost 10^3 AUSD$_{2004}$/km	**Lifetime**	**Interest rate**	**Annual O&M costs**	**Consumption for compression along the pipeline**	
330,000	50	10.83%	2% of annual capital charge	2% of delivered hydrogen energy	

The delivery of compressed hydrogen gas via tube trailer trucks is the second transmission alternative here analyzed. The different layout of the system in the two centralized production pathways is here represented by using different values for the estimated average delivery distance and number of deliveries per day. The adopted cost data are converted in Australian Dollars from the original data presented in [18,23]. It is assumed that the trucks are equipped with diesel engines. The fuel economy figure used in this study is the one reported in [20] for current technology articulated trucks traveling on Australian roads. It is assumed that two trucks at a time represent the addition in transportation capacity. The values adopted for the analysis presented in this study are reported in the table below.

Table 9 - Summary of modeling assumptions for truck hydrogen transport

Pathway	Truck Capacity kg_{H2}/delivery	Tube pressure MPa	Average delivery distance in km	Availability	Deliveries/day	Fuel economy l/100 km
Centralized at Demand Centres	480	16.55	100	85%	3	40
Centralized at Wind Farm sites			200		2	
Capital cost data AUSD$_{2004}$ Cab	**Trailer**	**TOTAL**	**Interest rate**	**O&M costs AUSD$_{2004}$/yr**	**Fuel cost AUSD$_{2004}$/l**	**Lifetime**
170,000	430,000	600,000	10.83%	70,000	0.75	15 years

Refueling stations for centralized hydrogen pathways

For the scope of the analysis presented here the main characteristics of the refueling stations are assumed to remain the same for each production pathway. This means adopting, for the two centralized production pathways, the same figures presented for the components downstream of the electrolyzer in the distributed production modules. The dispensing capacity is fixed at 0.48 t_{H2}/day and the hydrogen storage capacity at 720 kg. This simplification means in particular that the costs and consumption figures for the compressors adopted at the refueling stations to raise the pressure from the 16.55 MPa (tube trailer trucks) or (pipeline) to the storage pressure of 48.26 MPa are assumed to be the same. Moreover, it is assumed that the storage at refueling station sites is large enough to ensure a correct operation unaffected by the daily load profile characteristics of the demand for hydrogen[17]. The table below reports the main characteristics of the refueling station module.

Table 10 - Summary of modeling assumptions for refueling stations

Dispensing capacity	**Consumption**	**Storage (at 48.26 MPa)**	**Dispensing pressure**	**Capacity Factor**
t_{H2}/day	kWh/kg_{H2}	kg	MPa	85%
0.48	7.16	720	34.5	
Total Capital Cost	**Electricity cost**	**Interest rate**	**Annual O&M costs**	**Lifetime years**
$AUSD_{2004}/kW_{H2}$	$AUSD_{2004}$/MWh	10.83%	5% of annual capital charge	20
1200	7.6			

8. Modeling results

Reference scenario

The scenario adopted as the baseline for this model is the same originally developed for the *TasmaniaOEPC* LEAP model described in [11,12]. A key assumption is the population of Tasmania to grow as in the first of the three forecasts presented in [1]. Among other drivers of energy demand the value added of the Industrial, Agricultural and Commercial&Services sectors in Tasmania is assumed to grow at the rates forecasted in [28] and the energy demand to follow these trends respecting elasticities interpolated from a recent study of Australian trends in energy intensity published by ABARE [29]. The modeling of the Tasmanian road transportation sector is performed instead featuring a detailed stock turnover modeling based on the original data in [19,20]. The emission factors adopted, where available, are derived from the latest update of the *Factors and Methods Workbook* issued by the Australian Greenhouse Office and integrated with those available through the Technology and Environment database built in the LEAP^{TM} software.

Hydrogen demand

The chart shows the total projected demand for hydrogen from the Tasmanian road transportation sector resulting in each of the four scenarios of hydrogen vehicle sales penetration in the Tasmanian Light Duty vehicle market.

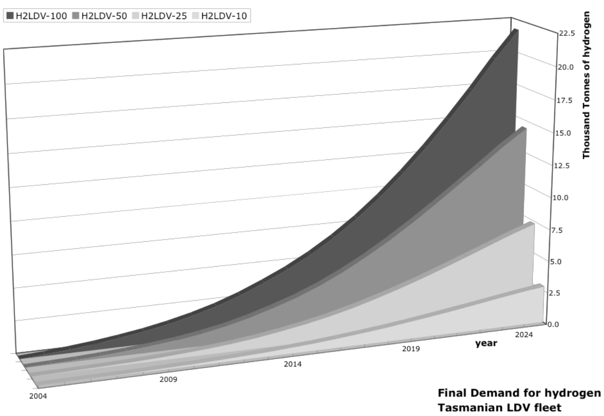

Figure 6 - Final projected demand for hydrogen

17 The evaluation of the impact of these simplifications and the evaluation of storage strategies will be performed in future research activities

The following table reports the total final energy consumption in the whole Tasmanian road transportation sector in the reference scenario and in the four hydrogen demand scenarios.

Table 11 - Final energy demand Tasmanian road transportation sector

	PJ/year				
year	**2005**	**2010**	**2015**	**2020**	**2025**
Reference	20.86	24.51	26.77	27.83	27.89
H2LDV-10	20.86	24.48	26.67	27.55	**27.38**
H2LDV-25	20.86	24.45	26.51	27.12	**26.59**
H2LDV-50	20.85	24.38	26.25	26.42	**25.33**
H2LDV-100	20.84	24.26	25.95	**25.80**	**24.05**

It is noted that the value of total final energy consumption decreases for each of the hydrogen scenarios with respect to the reference with the maximum reduction set at 13.77% over the 2025 value. The values reported in bold font highlight the inversion of the trend in final energy consumption, which starts to decrease between 2020 and 2025 for the 10, 25 and 50% sales penetration scenarios and between 2015 and 2020 for the 100% scenario.

The next table shows the global warming potential (CO_{2eq}) associated with the total final energy use in the Tasmanian road transportation sector. The lower section of the table illustrates the emissions reduction, with respect to the reference scenario, obtained as a result of the four hydrogen demand scenarios.

Table 12 - Projected Global Warming Potential (CO_{2eq}) Tasmanian Road Transport

	10^3 tCO2eq/year				
year	**2005**	**2010**	**2015**	**2020**	**2025**
Reference	2760	3300	3620	3760	3790
	Avoided emissions				
H2LDV-10	-0.43	-6.00	-24.19	-65.43	-120.17
H2LDV-25	-1.05	-13.92	-59.72	-165.77	-304.32
H2LDV-50	-2.25	-29.69	-121.58	-327.45	-598.16
H2LDV-100	-5.27	-56.72	-189.46	-470.21	-898.56

Hydrogen supply

In the chart below is reported the value of daily hydrogen demand for the 50 and 100% sales penetration scenario along with the resulting needed hydrogen capacity for three of the production pathways: distributed at refueling stations, centralized at demand centers and centralized at wind farm sites, both with pipeline transmission of the produced hydrogen.

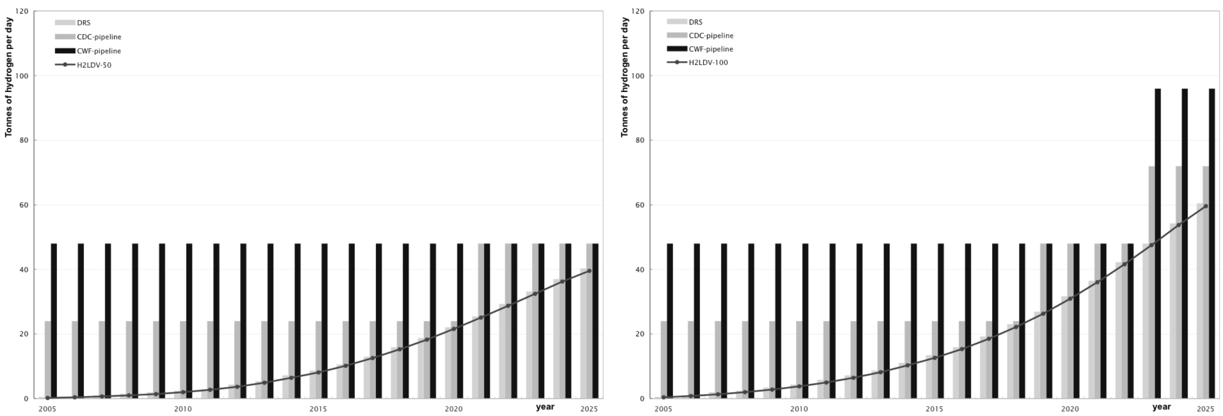

Figure 7 - Capacity needed in the 50% and 100% sales scenarios for different pathways

It is evident the different capacity of the three solutions in meeting the demand for hydrogen, with both centralized production options resulting largely oversized in the early market development.

The four charts below show the total annualized expenditure necessary to the provision of hydrogen to the Tasmanian light duty vehicle fleet in each of the sales penetration scenarios.

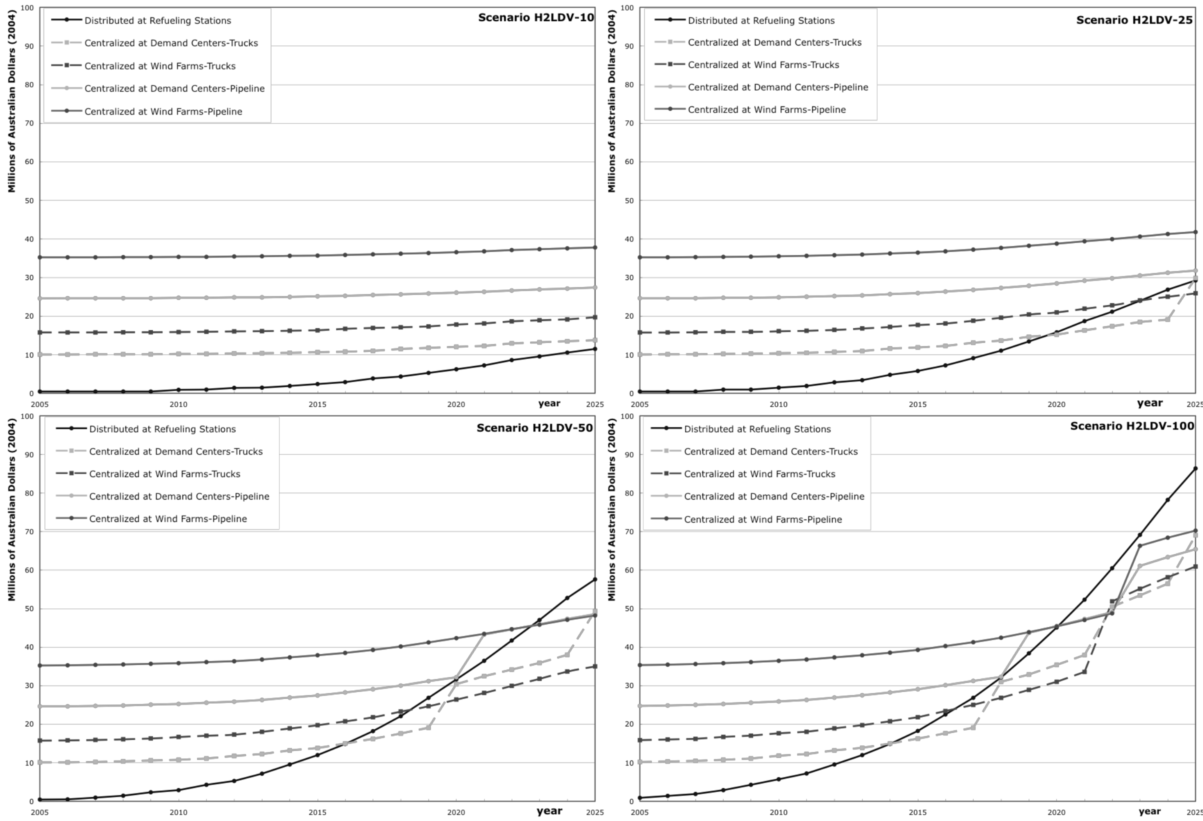

Figure 8 – Projected annualised expenditures for hydrogen energy infrastructure

The two centralized pathways with pipeline transmission present the highest capital costs, resulting thus particularly penalized in the two lower penetration scenarios. With the increase in energy demand the distributed electrolysis at refueling stations pathway starts to lose competitiveness as early as in the 25% penetration scenario: the annual expenditure for this pathway becomes higher than in the two pathways with tube trailer truck transmission. Every steplike increase in total annual expenditures reflects a capacity addition. It is noted how, for the same production pathways, the option with tube trailer trucks causes production capacity additions to be, in the higher penetration scenarios, almost regularly anticipated of one year with respect to the same production pathway featuring pipeline transmission. This behavior is driven by the larger losses associated with the first transmission mode and the resulting increased production requirements to meet the same final demand for hydrogen. Moreover tube trailer truck transmission presents the higher fuel and variable costs.

In Figure 9 is plotted the evolution of the electricity generated at the Woolnorth and Musselroe wind farms along with the electricity required for electrolysis in the pathway involving centralized hydrogen production at wind farm sites with pipeline transmission.

The chart shows a good match between the electricity requirements for electrolytic hydrogen production and the electricity generated at the two wind farm sites, with the needs projected to exceed the power generation at wind farm sites in 2025, only for the 100% vehicle sales penetration scenario. A more detailed analysis however reveals how the electricity need at the electrolyzers will exceed the maximum output (at an average 40% capacity factor over the planning horizon) of the current generation capacity at Woolnorth (stage 1 and 2, 64.75 MW) in the 100%, 50% and 25% vehicle sales penetration scenarios respectively by 2016, 2018 and 2022.

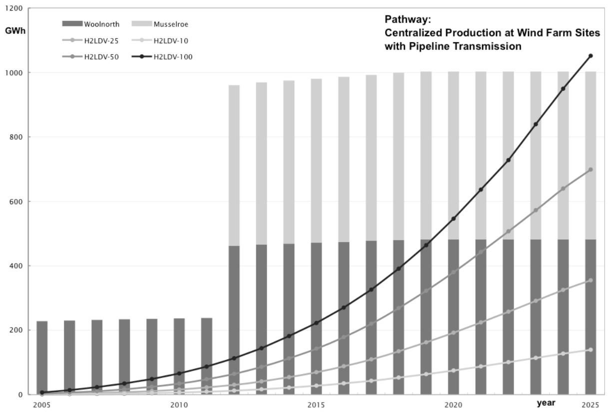

Figure 9 - Projected requirements for electrolysis and wind farms electricity generation

Moreover, in the two scenarios with 50% and 100% penetration, the electricity needed for hydrogen production, will exceed the maximum output of Woolnorth wind farm at its final planned capacity (130 MW by 2012). It is clear how delays in commissioning the planned additions in wind generation capacity could affect the availability of electricity for hydrogen production. A more in-depth analysis exploring the sensitivity of the system to these delays, the sensitivity to different levels of availability of the wind resource, and of the impacts over the whole Tasmanian energy system, will be presented in future research activities [16,17]

9. Conclusions

Under the modeling assumptions the penetration of hydrogen technologies in the road transportation sector results beneficial in terms of reduced overall emissions. It also benefits Tasmania in terms of reduced energy demand, contributing to reduce its actual total dependence from the imports of oil derivatives for transportation end-uses. Moreover, the results here presented show, under each of the four hydrogen vehicle penetration scenarios, an adequate match between the available, online and planned, wind generation capacity and the projected demand for hydrogen in the 2005-2025 planning horizon,. It should be noted, however, that some of the assumptions adopted for the scope of this study might result in an underestimation of the impacts that the development of a hydrogen energy infrastructure could have on the wider Tasmanian energy system.

In particular, on the electricity supply side, it has been assumed that each of the hydroelectric catchments maintains, during the entire planning horizon, a capacity factor equal to 80%. This value does not reflect the availability of water in the storages and would result more than optimistic under drought conditions. Same considerations could be made for wind generation, where the capacity factors (of about 40%) here adopted are derived from models of the planned and proposed wind farms developed with RETscreen®, based on the values of long-term mean wind speed reported by NOAA [8]. A sensitivity on the availability of wind resource, and more important, scenarios that explore the outcomes of delays or cancellation of the proposed wind farms projects could reveal an excessive pressure over the current generation capacity, even with the option of importing power from the mainland through Basslink. To this should be added that the demand for hydrogen here projected represents only a fraction, of the potential demand associated with a mature market in which the use of hydrogen is extended to the whole range of road vehicle types and classes. These potential *stress* factors could eventually be more than counterbalanced by options on the demand side. First of all, the potentials for *fuel switching* from electricity to natural gas in residential and commercial buildings, for the end-uses where this solution is energetically sound (cooking, space and water heating). The other solution, maybe the most important, is represented by the opportunities for energy efficiency across all of the Tasmanian energy consuming sectors. The analysis of these options and their possible interplays, under the principles of Integrated Resource Planning, will be presented in successive publications [16,17]. The study here presented is aimed to identify major advantages and drawbacks associated with each of the proposed hydrogen infrastructure pathways, and the results here presented are used as the basis for further research activities. For what concerns the choice of the perspective hydrogen infrastructure, the major insights derived from the top-level analysis presented in this paper are: 1) the scarce ability of the pathway involving the production at wind farm sites in guaranteeing an adequate support to Hobart, the major urban centre, accounting for more than half of the population and its scarce ability to "fuel" the hydrogen demand, under eventual delays in commissioning the planned wind generation capacity; 2) the clear disadvantage of the tube truck trailer transmission alternative induced by the scarce transportation capacity compared to other modes; 3) the high capital costs associated with the development of a statewide hydrogen pipeline under the demand growth scenario here presented, makes the centralized pathways not competitive with the distributed option for most of the planning horizon. Further research activities will be focused on addressing the question of whether a purely centralized or distributed infrastructure will be able to satisfy the growing demand for hydrogen, including uses others than the only Light Duty vehicles market and investigate the advantages of building up a hybrid infrastructure design in which the first solution is integrated, to achieve an adequate spatial coverage in rural areas, with small-scale distributed production plants. In this latter case further analysis will then focus on trade-offs between distributed generation and transmission of gaseous hydrogen via pipeline or liquid via cryogenic truck, not presently scoped.

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