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Hydrogen Strategies: an Integrated Resource Planning analysis for the Development of Hydrogen Energy Infrastructures

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ABSTRACT

Major funding programs for RD&D started worldwide and the booming hydrogen-energy research field are clear symptoms of an increased attention focus on hydrogen as the next best energy option.

How does this flourishing of activities translate into effective steps towards a hydrogen economy? What are the best options for the development of hydrogen-energy infrastructures from the embryonic stages to their well-established perspective roles in the wider regional, national and international energy economies? What are the real benefits delivered by hydrogen energy systems in terms of reduced energy dependence and environmental load of energy-related activities? What are the possible synergies and interplays with the other energy pathways?

The key elements and ultimately the shape of future hydrogen energy economies will depend on their geo-economic characteristics and current energy infrastructure. In different geographic contexts, to quote some, different will be the potential primary resources for hydrogen production, different the issues associated to location and characteristics of the potential demand for hydrogen-energy services and different the issues related to the siting of hydrogen-energy infrastructure.

The evolution of the energy system, the characteristics of its infrastructure, the actual and projected mix of primary sources and conversion technologies together with the characteristics demand served are key elements to understand where hydrogen systems could better fit, taking advantage of side effects and synergies with the existing energy chains.

An extensive analysis of the current energy economy under the principles of Integrated Resource Planning (IRP) helps the assessment of hydrogen production potentials and to identify barriers and drivers for hydrogen-energy developments. The results of this analysis and the scoping of alternative hydrogen scenarios under the IRP approach are presented here for the case study of Tasmania (Australia). The rationale for the application of the methodology to the case studies of California (USA) and Sardinia (Italy) is also presented.

The outline of a methodology for the analysis of hydrogen infrastructure development strategies integrating IRP, energy systems and GIS-based modeling is also presented.

Keywords: Hydrogen Infrastructure, Renewable Hydrogen, Energy Planning, Energy Systems Modeling, and Scenario Analysis.

1. INTRODUCTION

Hydrogen futures are largely unknown. The choice of energy sources for hydrogen production and the processes to be employed represent a clear example of some of such critical uncertainties.

Other critical uncertainties are likely to influence the shape of a future hydrogen energy system and determine if the transition to this is to happen at all:

- the timing and extent of the transition;
- the cost and performance achievements in technologies to be employed on the supply and demand side;
- whether hydrogen end-use technologies will gain or not consumers' acceptance.

Where, on one side, these large areas of uncertainties do exist, on the other side it is clear how such a transition will require economic and technological efforts comparable to the development of the electricity and oil derivatives production and supply infrastructures our economies now rely heavily upon. Such high level objectives require the active participation and careful coordination, side by side to energy companies, of institutional subjects, technology providers and other stakeholders such as consumers' associations and environmental NGOs.

It appears necessary to develop occasions and methods to enhance an enlarged discussion of these broad objectives we, as a society, are willing to pursue in designing a role for the hydrogen carrier in our energy economies. These should be then adopted as the basic input for a participatory approach the development of the strategies that will help us to get there.

In this paper are presented the rationale and practice of the application of scenario analysis and tools and methods developed for Integrated Resource Planning for scoping the alternative pathways for the development of future hydrogen-energy systems.

2. HYDROGEN STRATEGIES

The question *why hydrogen?* remains central to the planning phase of such a transition allowing us to develop strategies clearly directed to the achievement of the envisaged benefits of the adoption of hydrogen energy systems to serve as backbones of our future energy economies. Such benefits, it is always worth mentioning, are:

- **Environmental benefits on a global scale:** reduction of greenhouse gases emissions in the atmosphere and mitigation options;
- **Environmental benefits on a local/regional scale:** reduction of urban air pollution, reduction of local and regional environmental impacts associated with the operation of energy systems;
- **Energy related benefits:** enhanced diversity, self-sufficiency and security of energy supply;
- **Economic benefits:** new economic activities associated with the development of a green-field market, repositioning of regional and national players in the international context.

The perceived relative importance of the above-mentioned benefits is likely to be affected by regional consideration on resource availability, environmental pressure and socio-economic conditions. It is undoubted how a strategy for the adoption of hydrogen energy systems, from their embryonic stages to their well established roles in the wider energy economies should address the achievement of some of these goals.

Strictly speaking a strategy for the development of hydrogen energy infrastructures is a consistent set of actions that defines the path starting from RD&D hydrogen activities to starter and established markets for the hydrogen carrier and related technologies. The outline of a strategy is bound with addressing the question *hydrogen how?* How, in particular, to develop hydrogen energy infrastructures able to deliver the benefits we associate with hydrogen? What are the pathways able to improve our energy economies reducing environmental impacts and increasing self-sufficiency? The answer is neither trivial nor straightforward. Different geographical and socio-economical contexts will lead to different hydrogen pathway solutions.

3. THE NEED FOR PLANNING

The hydrogen transition is likely to require substantial investments in the development of the backbone infrastructure to allow adequate access to the end-users since the early stages of the hydrogen markets. The adequate availability issue represents a crucial element to gain consumers' acceptance, which in turn will be the key element of the viability of the transition. To these massive investments are to be added financial and fiscal actions to foster the diffusion of the technologies among the early adopters.

It is apparent how governmental intervention will play a pivotal role in supporting the efforts of energy companies involved in hydrogen production and distribution on one side and technology providers, such as automakers, on the other side.

Public spending in this area should address the concurring needs dictated by the minimization of environmental and energy constraints and the maximization of economic benefits. It is necessary then to provide the decision-maker with an adequate knowledge on the outcomes of policy decisions under several alternative socio-economic scenarios.

- The IRP approach, providing a common ground for the evaluation of energy alternatives, seems the best suited to analyze the role of hydrogen in the wider context of the whole energy economy assessing barriers and potentials and highlighting win-win interplays between hydrogen and other energy alternatives.

4. OVERVIEW OF THE PLANNING FRAMEWORK

4.1 Role and importance of scenario analysis

The research activities here presented aim at the integration of aspects of strategic planning and energy analysis to develop alternative hydrogen-energy scenarios. The scenarios developed are both are exploratory and analytical (Ghanadan and Koomey 2005) and their employment as a strategic learning tool (Bood and Postma 1997) is meant to foster a cooperative approach among better informed stakeholders and public decision-makers for the outline of appropriate strategies. The business community first adopted scenario methods for organizational learning in the 1960s with the activities of a group of ex Royal Dutch/Shell scenario planners among the most notable of such applications.

The scenario method is applied to the scoping of alternative hydrogen energy pathways to characterize an envelope of future expected macroeconomic conditions (Ghanadan and Koomey 2005) and to identify the potentials for production of hydrogen and diffusion of hydrogen end-use technologies.

The uncertainties surrounding the future of hydrogen energy requires a careful analysis of several alternative plausible storylines in order to develop strategies, which are sound and flexible under different scenario assumptions. These ''hydrogen-energy scenarios'' are a set of illustrative energy pathways that are created using a distinct scenario development methodology and quantitatively analyzed using energy modeling techniques (Ghanadan and Koomey 2005).

4.2 Integrated Resource Planning

A detailed and extensive analysis under the principles of Integrated Resource Planning (IRP), preliminary to the further exploration of hydrogen futures will give the necessary insights of the energy economy considered for the planning process of any energy alternative.

The IRP process promotes, among energy alternative scenarios, the ones able to provide the same projected level of energy services demanded by end-users, at the least total cost. Total costs include any monetary and non-monetary costs (environmental and social externalities) associated to energy related activities, from primary source extraction to end-use.

Accounting internal and external costs together the IRP process provides then a common criterion of evaluation for the wider range of energy options. Energy efficiency, Renewable Energy Systems and fuel switching options enjoy, under this approach, economic attractiveness and overall competitiveness with respect to traditional fossil-based energy systems.

This broader scope of IRP appears then well suited to analyze, at a system level, opportunities for the introduction of a new energy carrier such as hydrogen.

The development of a preliminary IRP analysis provides with a detailed knowledge of the system, its peculiarities and its sensitivity to economic and demographic factors, of the potentials for renewable energy sources, together with the impacts of planned and proposed energy projects.

This analysis is carried by means of models of current energy infrastructures developed with the LEAP™ software. The main outcomes of this analysis are:

- Baseline energy projections;
- Review of undergoing, planned and proposed energy projects and their likely impact in term of reduction of energy imports and pollutant (greenhouse-gases and macro pollutants) emissions;

And, with particular regard to hydrogen:

- Identification of potentials for hydrogen production from endogenous energy sources;
- Assessment of technical and socio economical barriers to hydrogen introduction present at the different levels of the economy.
- Evaluation of hydrogen end-uses, given the structure of the energy end-use sectors, likely to be stimulated;
- Preliminary assessment of levels of hydrogen demand associated with different degrees (and time patterns) of penetration of hydrogen end-use technologies within the planning horizon.

4.3 LEAP-based modeling

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 Swisher et al. (1997) and Sathaye et al. (1998). 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:

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

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

$$Energy\_use = \sum_i N_i \cdot P_i \cdot M_i \cdot I_i; \qquad (2)$$

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. 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™ 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.

For example, in the model *Tasmania H2Pathways*, developed for the analyses presented in the following paragraph are scoped 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, have been presented in (Pigneri and Spazzafumo 2005).

5. THE CASE FOR TASMANIA

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 by 2025 in three forecast scenarios recently released by the Australian Bureau of Statistics (ABS 2001)[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.

The power generation system on mainland Tasmania comprises currently 30 power stations of which 28 hydroelectric, the other two being Woolnorth wind farm (currently 64.75 MW) and Bell Bay thermal power station (NG-fired steam cycle, 240 MW). 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. The table below provides an overview of the installed hydroelectric capacity.

Table 1: Tasmanian hydroelectric system

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**

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.

[1] The figures from the original ABS scenarios, released in 2001, have been normalized to the figure for the 2004 estimated residential population published on the 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.

In a previous study (Pigneri and Spazzafumo 2005) a preliminary analysis of the robustness of such a vision has been presented: a multi-level modeling framework has been employed to assess strengths and weaknesses of three alternative pathways for hydrogen production, transmission and distribution in Tasmania. The modeling framework, employed tools and methods derived from energy planning, energy systems modeling and GIS-based analyses a detailed description of the modeling effort and of some key results is presented in the remainder of this paragraph.

5.1 Hydrogen demand scenarios

The study presented in (Pigneri and Spazzafumo 2005) analyzed 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) 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 2: 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 with values adopted in (Ogden et al. 2004) 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 (ABS 2004), allowing for a reasonable evaluation of the inertia the characteristics of existing fleets represent as opposed to a vehicle technology switch.

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 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.

5.2 Pathways analysis

The three hydrogen infrastructure pathways explored in (Pigneri and Spazzafumo 2005) are the ones depicted in the figure below:

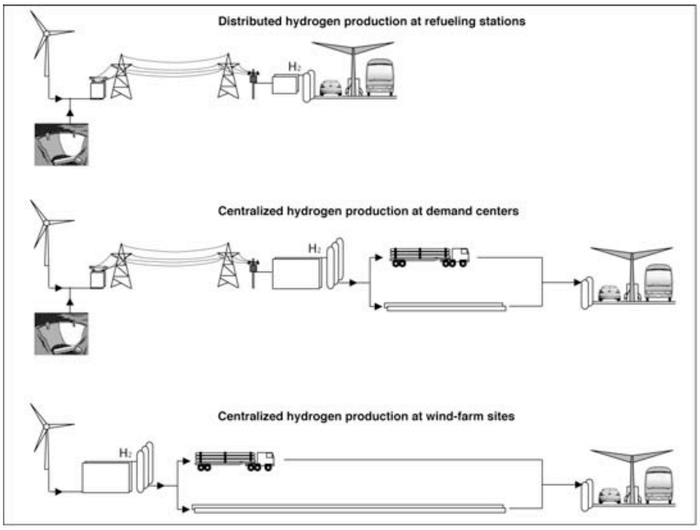

Figure 1: Scoped Hydrogen Pathways for Tasmania

5.2.1 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. The distributed electrolyzer refueling station modules in the model are based on performance and cost figures of the Stuart Energy Stations featuring IMET1000 serie electrolyzers. The capacity of distributed hydrogen production is fixed in 0.48 t_{H2}/day for ease of comparison with other studies. 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). The table below reports the operational and cost data used in the model for the distributed production pathway.

Table 3: 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	**Total Aux.**	**TOTAL**			
$AUSD_{2004}/kW_{H2}$		**$AUSD_{2004}/kW_{H2}$**	10.83%	5% of annual capital charge	20
3200	1800	**5000**			

5.2.2 Centralized hydrogen 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. The size of each production unit is fixed at 24 tH2/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 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.

5.2.3 Centralized hydrogen 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 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 4: 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 $AUSD_{2004}/kW_{H2}$	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		

5.2.4 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 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. For the scope of this study an eventual compressed hydrogen pipeline development is simply assumed to develop along the existing gas pipeline route.

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.

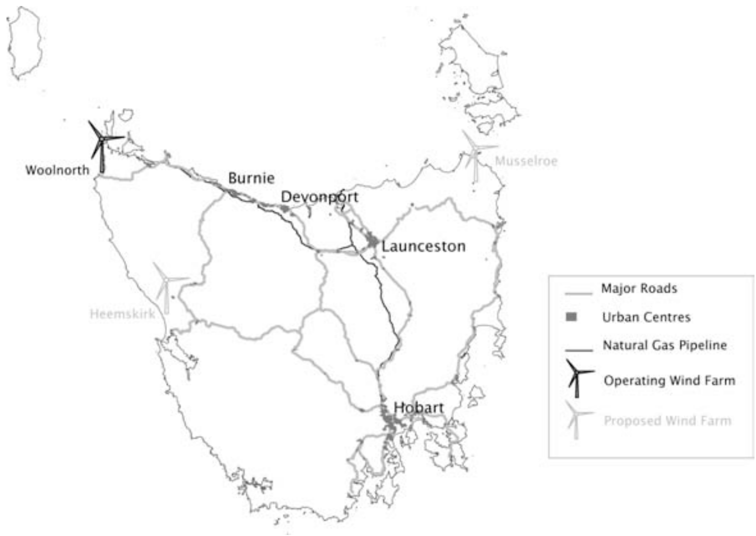

Figure 2: Major urban centers, roads, gas pipeline route and wind farm sites, Tasmania

The table below reports the modeling assumptions for operational and cost parameters of the pipeline modules.

Table 5: Summary of modeling assumptions 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. It is assumed that the trucks are equipped with diesel engines. The fuel economy figure used in this study is the one reported in (ABS 2004) 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 6: 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

5.2.4 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. The table below reports the main characteristics of the refueling station module.

Table 7: 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			

5.3 Modeling results

5.3.1 Reference scenario

The scenario adopted as the baseline for this model is the same originally developed for the TasmaniaOEPC LEAP model described in (Pigneri 2004). A key assumption is the population of Tasmania to grow as in the first of the three forecasts presented in (ABS 2001).

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 (Adams 2002) and the energy demand to follow these trends respecting elasticities interpolated from a recent study of Australian trends in energy intensity published by ABARE[2]. The modeling of the Tasmanian road transportation sector is performed instead featuring a detailed stock turnover modeling based on the original data in (ABS 2004). 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™ software.

5.3.2 Hydrogen Demand

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 8: 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.

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[2] Australian Bureau of Agricultural and Resource Economics

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 9: 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

5.3.3 Hydrogen Supply

In the two charts 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.

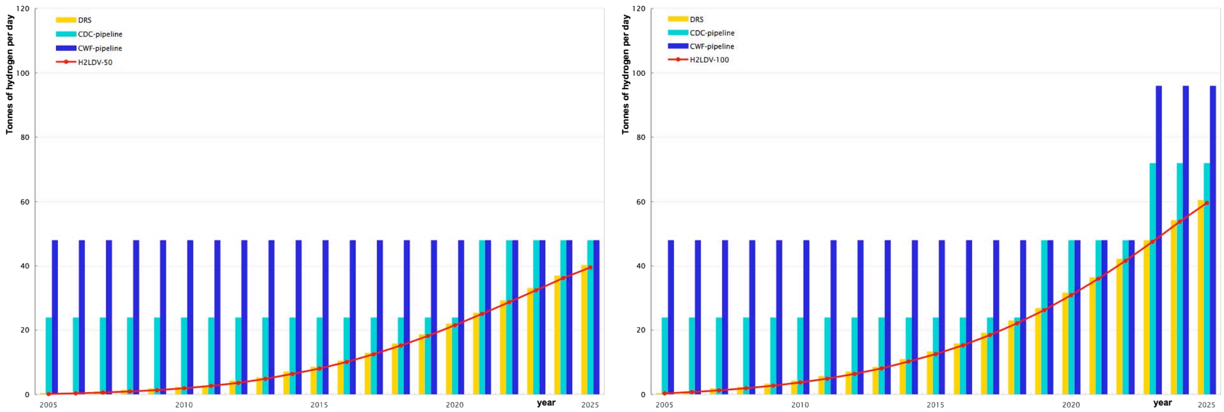

Figure 3: Capacity needed in the 50% and 100% sales scenarios for different pathways

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 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 the figure below 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.

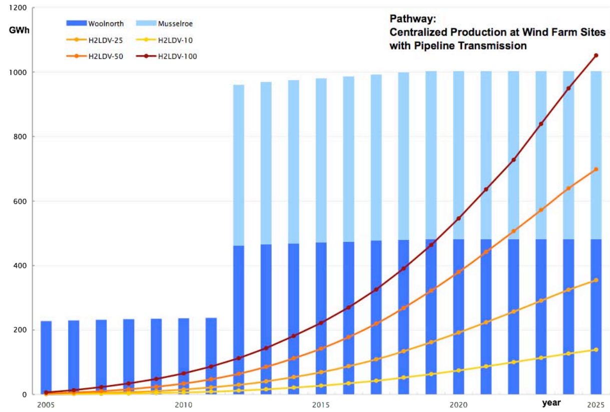

Figure 4: Projected requirements for electrolysis and wind farms electricity generation

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.

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.

5.4 Directions for future work

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[3]. 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

[3] National Oceanic and Atmospheric Administration

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 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.

6. OTHER CASE STUDIES

In parallel with the further development of the analysis for the Tasmanian case study, in collaboration with Hydro Tasmania two other case study have been recently developed, in the remainder of the paragraph will be provided a brief description of the modeling efforts and the major element of interest in the framework of the scenario activities previously described.

6.1 California

A study has been recently initiated at University of California Davis analyzing the futures of the hydrogen and electricity systems in California. The study, under the auspices of the California Energy Commission, is meant to analyze several alternative pathways to the development of hydrogen energy infrastructures in California and to evaluate the relative stresses the two systems operate on one another (where they will draw from the same feed-stocks or are adopted as a feedstock to one another) and the possible win-win interplays.

In particular will be analyzed the opportunities eventually arising from an early and incisive energy efficiency programs in reducing pressure on the current electricity supply structure and allowing to free economic and energy resources for the development of early hydrogen energy infrastructures. Preliminary deliverables from the project will be made available in the early months of 2006.

6.2 Sardinia

A novel study focused on the adoption of scenario analysis in the development of a regional strategy for hydrogen is currently developed for Sardinia, Italy. The case study presents some similarities with Tasmania in being an island and in having consistent amounts of planned wind capacity, the introduction of natural gas and the connection to the Italian mainland electric system. A point of interest is the presence on the island of the world's most advanced refinery-based IGCC project (Sarlux plant at Sarroch) with an estimated hydrogen production of 40000 Nm^3/h. The study investigates the effective availability of some slipstream hydrogen for the needs of some starter demonstration hydrogen vehicle fleets.

A preliminary report for the study will serve as a basic informative material regarding the opportunities and challenges associated with the development of a regional hydrogen energy infrastructure and will be employed in the organization of scenario workshops to be held with various stakeholders around the island. The result of them will be integrated with the first development in a broader hydrogen strategy for the island.

7. CONCLUSIONS

The paper provides information regarding the importance and application of scenario analysis and Integrated Resource Planning tools and methods for the scoping of hydrogen energy futures.

The complexity of the various aspects involved with the development of hydrogen energy infrastructures provides a rationale for this approach. The development of detailed bottom-up model of the energy economies analyzed allows the identification of opportunities arising also from energy efficiency and renewable development helping to stream hydrogen policies into the wider context of energy policies.

The application of such a methodology to various case studies constitutes *per se* a learning opportunity which is likely to benefit largely the evolution of concepts and knowledge in hydrogen energy systems and their possible future role within our energy economies.

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