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2 **Using Surplus Nuclear Power for Hydrogen Mobility and Power-to-Gas in France**

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7
8 **Abstract**

9 *Opportunities exist to utilise excess electricity from renewable and nuclear power generation for*
10 *producing hydrogen. France in particular has a very high penetration of nuclear power plant, some of*
11 *which is regularly turned down to follow the electricity demand profile. This excess nuclear electricity*
12 *could be utilised via the electrolysis of water to satisfy the emerging French market for low-carbon*
13 *hydrogen (principally for mobility applications and the injection of synthetic gas into the natural gas*
14 *grid). The described analysis examines the use of electrolyzers to progressively ‘valley fill’ nuclear load*
15 *profiles and so limit the need for turning down nuclear plant in France. If an electrolyser capacity of*
16 *approximately 20 GW is installed, there is already sufficient excess nuclear electricity available now to*
17 *meet the predicted hydrogen mobility fuel demand for 2050, plus achieve a 5% concentration (by*
18 *volume) of hydrogen in the gas grid, plus produce approximately 33 TWh p.a. of synthetic methane*
19 *(via the methanation of hydrogen with carbon dioxide). The pattern of electrolyser utilisation requires*
20 *operation mostly at a variable part load condition, necessitating the adoption of flexible, efficient,*
21 *rapid response electrolyzers. The proposed approach more fully utilises the substantial existing nuclear*
22 *power assets of France and provides an additional pathway to renewables for reducing the CO₂*
23 *emissions of hydrogen production.*

24
25 **Highlights**

26

- 27 • Electrolyser operating strategies for increased utilisation of nuclear power generation in France
- 28 • Using excess energy for power-to-gas and hydrogen mobility applications
- 29 • Hydrogen for large scale power management in electricity transmission and distribution networks
- 30 • Demand side management with controllable electrolysis
- 31 • Decarbonisation of power, gas and transport systems through increased interconnection

32
33 **Keywords**

34 Electrolysers, power-to-gas, hydrogen mobility, demand side management, nuclear power utilisation

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36

37 **1. Introduction**

38 Power system decarbonisation strategies usually rely heavily on achieving greater deployments of
39 wind farms, solar photovoltaic arrays and nuclear power plant. As the penetration levels increase,
40 periods of excess energy (or over-generation) occur, because of the temporal mismatch between
41 electricity supply and demand [1] [2]. Maintaining the dynamic stability of the electricity grid is a
42 fundamental requirement and so electricity surpluses need to be exported immediately, absorbed or
43 curtailed as they occur. Curtailment is more widely practised in grids which have limited or no
44 interconnections to other grids, but in general it is caused by congestion constraints or dynamic
45 stability concerns [3]. A recent study commissioned by the Fuel Cell and Hydrogen Joint Undertaking
46 indicated that excess renewable electricity in Germany could amount to nearly 30% of the total
47 electricity demand by 2050 [4]. This characteristic of increasing amounts of excess energy per MW of
48 installed capacity weakens the case for achieving high penetrations of renewables or nuclear power
49 plant, unless electricity can be readily exported to a neighbouring grid or demand can simply be
50 increased when required [1] [2]. Exporting power as a means of increasing renewable or nuclear
51 power penetrations has been achieved in some regions (e.g. by Denmark, Germany and France) but,
52 as the magnitude and frequency of excess energy events increase, simply exporting surpluses to
53 neighbouring countries as they occur becomes less viable and more curtailment or absorption
54 (storage) is required.

55
56 By convention 'energy storage' has been assumed to comprise power-to-power storage (P2P)
57 technologies (such as pumped hydro, batteries and flow batteries), where electricity is absorbed at
58 one time and discharged as electricity at a later time. Energy storage technologies can thereby provide
59 power networks with 'peak shaving', 'valley filling' and renewable power management facilities [5].
60 However, their economic justification depends largely on the prevailing buy and sell prices for
61 electricity in a given region. Unfortunately because P2P storage acts to clip peaks as well as fill valleys
62 in the electrical load profile, its deployment affects adversely the buy/sell price ratio and so, in time,
63 the economic case for its utilisation is compromised - the law of diminishing returns applies [4].

64
65 In this context, it is desirable to widen the scope of the decarbonisation objective to include the
66 absorption of excess energy from the power system for use in the transport and gas systems. The
67 fundamental energy conversion process that is required to achieve this is the electrolysis of water to
68 produce hydrogen. By this means excess generation can be exported by:

69
70 • injecting hydrogen (or synthetic methane derived from hydrogen and carbon dioxide) into the
71 gas grid – usually referred to as 'power-to-gas'
72
73 • storing hydrogen in electrolyser-based Hydrogen Refuelling Stations (for refuelling fuel cell
74 vehicles)
75
76 • storing hydrogen for example in salt caverns for power/heat generation.

77
78 Thereby installed capacities of renewables and nuclear power can continue to grow without
79 necessarily causing curtailment to increase, because demand is not constrained by the transient
80 demand profile for electricity. By effectively utilising hydrogen to interconnect the power, gas and
81 transport systems, a substantial over-generation of power in the power system can be accommodated
82 and usefully employed [6] [7] [8] [9] [10]. Furthermore, in solar-dominated regions the steep ramp in
83 the power requirement from thermal power plant during late afternoon can to some extent be
84 ameliorated [11].

85
86 This approach may be applied in many countries as a function of the availability, form and capacity of
87 the gas grid, salt caverns and hydrogen mobility (H2M) infrastructure. In islands with relatively weak

88 electricity grids, or regions with limited interconnections to neighbouring grids (e.g. the UK), the need
89 to implement an indigenous solution must be faced at relatively low renewable power penetrations
90 [12]. Conversely strong continental electricity grids can often transmit excess electricity to another
91 region of lower renewable power penetration; for example, this currently occurs in Southern Germany
92 due to the high solar PV penetration (Figure 1) [13]. However, for all regions, as the renewable or
93 nuclear power penetration grows, it becomes increasingly desirable to utilise the excess electricity
94 locally if curtailment is to be minimised.

95
96 France has a remarkably low carbon intensity for electricity generation of 61 gCO₂/kWh_e due to its
97 large nuclear power capacity [14], but it remains heavily dependent on imported fossil fuels for
98 providing heat and mobility. In 2013 transport fuel, natural gas and electricity requirements were
99 similar, amounting to 494, 470 and 498 TWh respectively [15] [16] [17]. However, their demand
100 characteristics vary significantly, with the gas demand profile exhibiting the greatest variation across
101 the year (Figure 2). Outline consideration of Figure 2 suggests that the French transport and gas
102 systems should be able to readily accommodate any surpluses emerging from the valleys of the
103 national electrical load profile.

104
105 In 2013, nuclear power stations in France delivered 402.1 TWh (*i.e.* 80.7% of total electricity
106 generation) [15], with a net total of 51.7 TWh of electricity exported to neighbouring countries, making
107 France the biggest exporter of electricity in Europe [18]. The installed nuclear capacity is presently
108 63.2 GW and the annual load factor is therefore about 73%. In addition, France has about 40 GW of
109 renewables (including 25.4 GW of hydro, 8.3 GW of wind and 4.7 GW of solar in 2013) [19] [20] [21]
110 [22] [23]. In 2015 the French Parliament adopted an energy transition bill (2015-922) which will
111 initiate a number of significant changes to France's energy landscape [24]. The bill's objectives include
112 a 40% reduction in greenhouse gas emissions by 2030 compared with 1990 levels, with a 75%
113 reduction by 2050. Fossil fuel consumption will be reduced by 30% compared with 2012 levels by
114 2030, with the share of renewables in final energy consumption increasing to 32% (40% of electricity
115 production). Nuclear capacity will be capped at the present level of 63.2 GW, with the share of nuclear
116 energy in electricity production falling to 50% by 2025. This transition away from fossil fuels towards
117 a power system based almost entirely around nuclear and renewables by 2050 implies that France will
118 experience very large amounts of excess renewable electricity and/or excess nuclear electricity.

119
120 When compared with other nations employing nuclear power, France is unusual in that it applies a
121 number of methods to control core reactivity in nuclear power plant, so that the total nuclear power
122 generation profile can better follow the daily electricity demand profile as it unfolds [25] [26].
123 However, turning nuclear reactors down on a frequent basis decreases the return on capital
124 investment [27], it reduces the sales income that would otherwise have been achieved had a greater
125 electricity demand existed at these times [26], it incurs plant costs, and it increases waste as boric acid
126 is used to reduce the rate of reaction which increases the volume of effluents generated [28]. Instead
127 if nuclear electricity could be utilised effectively during these periods, the annual load factor could be
128 increased (within the limits driven by plant maintenance) and nuclear power could make a greater
129 contribution to decarbonising the French energy system without needing to increase installed
130 capacity. These periods of turn down, which occur at different times of day/year, represent surpluses
131 of nuclear power. The associated amounts of electrical energy are referred to here for convenience as
132 'excess nuclear'; this is analogous to 'excess renewables' when renewable power sources need to be
133 turned down/off at times of low demand and high availability. Electrolyser operation to utilise excess
134 energy in a generic power system containing various proportions of renewable and base load zero-
135 carbon (nuclear) power plant have been investigated previously [1].

136
137 To help frame the opportunity for excess energy to be employed to enable hydrogen mobility and
138 power-to-gas (P2G) in France, this investigation considered recent nuclear generation profiles. It made

139 no attempt to predict future nuclear load profiles or to estimate future levels of excess nuclear
140 electricity, which will be influenced both by the installed capacities of renewables and future
141 electricity demand profiles.

142
143 By definition if something is otherwise unsaleable it is of low or zero value. Therefore the absorption
144 of otherwise unsaleable excess nuclear electricity by electrolysis means this electricity should be
145 available to electrolyser operators at a low unit price [29] [30]. Rapid response electrolyzers may also
146 sell balancing services to the electricity grid operator to enable the electrolysis load to be switched on
147 or increased when required [31], rather than requiring the nuclear plant to be turned down. In the
148 envisaged approach, electrolyser operation would be controlled to utilise only excess nuclear
149 electricity so that the average load factor of nuclear plant would increase. The electrolysis load would
150 thereby augment consumer demand for electricity and play an increasingly central role in electricity
151 supply-and-demand management [32].

152
153 The main objectives of this study were to identify the required electrolyser operating profiles if excess
154 nuclear is utilised and to estimate the magnitudes of the contributions that this energy could make
155 towards meeting hydrogen mobility and power-to-gas requirements in France. With respect to P2G,
156 both hydrogen injection (H2I) and methanation (SNG production using hydrogen and waste carbon
157 dioxide) were considered.

158
159
160 **2. Nuclear Generation Profiles**
161 The annual variation in nuclear power generation in France for 2011-13 is shown in Figure 3. A
162 relatively high reliance on electric heating results in a peak in nuclear power output during the colder
163 winter months of around 60 GW (close to the total nuclear capacity), while output drops to around 40
164 GW during the summer. Nuclear generation averaged 408.4 TWh p.a. over the period 2011-13, which
165 is 73.8% of the 553.5 TWh p.a. that could have been generated in an idealised scenario where the
166 entire nuclear fleet operates continuously. This hypothetical scenario means that up to about 145
167 TWh p.a. of nuclear generation is being curtailed. Of course the availability of a nuclear power plant
168 is significantly less than 100%, because it must undergo regular maintenance, so this hypothetical
169 potential cannot be realised. In practice the unit capability factors (UCF) for nuclear power plant in
170 France in 2014 ranged from 50.3% to 99.7% [33]. Of the 57 operating plant, 47 were characterised by
171 an average UCF of 85% while 31 stations achieved an average UCF of 91% - the latter indicates that
172 load factors well in excess of the national average are achievable.

173
174 In this investigation it was assumed that the additional opportunity to produce hydrogen with excess
175 nuclear would motivate the power industry to ultimately achieve an average UCF of 91%. Achieving
176 this very ambitious target would correspond to providing 100 TWh p.a. of excess nuclear for hydrogen
177 production. Previous investigations have identified much smaller surpluses of 19.2 and 22 TWh
178 occurring in 2004 and 2007 respectively, but these represent the difference between actual
179 production and consumption, not potential production at maximum capability and consumption [29]
180 [30]. It may take some years to achieve the 100TWh target, but we cite this to provide an indication
181 of the amount of electricity that is potentially available for electrolysis without requiring the existing
182 nuclear capacity to be expanded.

183
184 Weekly average nuclear power generation profiles for winter (Nov-Mar) and summer (Apr-Oct) for
185 2011-13 show regular patterns in the requirement placed on nuclear power plant across the day/week
186 (Figure 4). Typically there are two daily valleys; a dip of about 0.5 GW in early afternoon, and a deeper
187 valley of 1-2 GW overnight. In addition there is a deep weekend valley (including three nights, Friday
188 to Sunday) of as much as 7 GW below the weekday peak. Weekend and night-time valleys are deeper
189 in summer than in winter (7 GW versus 3 GW and 2 GW versus 1 GW respectively). These variations

190 in the average load profiles are driven mainly by varying consumer/industrial behaviour patterns
191 across the week and by weather variations across the year (e.g. different demand levels for electric
192 heating, air conditioning and lighting).

195 **3. Hydrogen Demand Predictions.**

197 Recent studies have estimated the potential for utilising hydrogen in the following three markets in
198 France: mobility, power-to-gas and power generation: [4] [34] [35] [36] [37].

201 **3.1 Mobility**

203 Fuel Cell Electric Vehicles (FCEV) are one of the main options for zero-carbon transport as they provide
204 longer ranges and much shorter refuelling times than battery electric vehicles (BEV). Germany, the
205 UK, California, Korea and Japan are building initial hydrogen refuelling station (HRS) networks to
206 support the early adoption of FCEVs in the 2015-2020 timeframe, rising to much larger numbers by
207 2030. Toyota, Hyundai, Honda, Nissan and Daimler have each announced plans to start selling FCEVs
208 in significant quantities, with Hyundai commencing sales in 2014.

210 A recent analysis for France called for 73% of the hydrogen consumed by FCEV in 2030 to be produced
211 via on-site electrolysis in order to achieve a CO₂ saving of 77% relative to new diesel cars in 2030 [34].
212 It recommended that France itself construct an initial network of 55 hydrogen refuelling stations by
213 2020, rising to 600 by 2030. This could support 773,000 FCEVs by 2030, requiring 61.4 kt p.a. of
214 hydrogen from electrolysis (~3.25 TWh_e p.a.) and a further 28.6 kt p.a. from reformed natural gas and
215 chlor-alkali plant. By 2050, electrolytic hydrogen production for FCEV refuelling could rise considerably
216 to 598 kt (requiring ~33 TWh_e per annum) for refuelling 7.3 million FCEVs.

217 Hence it is clear from this preliminary analysis that the current magnitude of excess nuclear available
218 in France far exceeds the predicted electricity requirement for meeting the 2050 hydrogen mobility
219 demand. Importantly in the period to 2030 the availability of only modest amounts of excess nuclear
220 (a few TWh p.a.) would be sufficient to provide a considerable boost to establishing the necessary
221 hydrogen refuelling infrastructure in France, and thereby assist fuel switching from diesel/gasoline
222 vehicles to FCEV.

224
225 **3.2 Power-to-Gas**

228 France currently consumes about 470 TWh p.a. of natural gas, primarily for heating. Decarbonising
229 the heat network remains a considerable challenge, and power-to-gas (P2G) offers a means for
230 switching from imported natural gas to indigenously generated synthetic gas. Electrolytic hydrogen
231 can be mixed with natural gas and injected into existing natural gas networks at low concentrations
232 and then combusted safely with existing burners and appliances [38]. A clear advantage of this
233 approach is that the infrastructure is already in place to convey and store large quantities of hydrogen
234 without the need for additional plant [39]. As most gas networks have not been designed to contain
235 significant quantities of hydrogen there is normally an upper limit to which hydrogen can be injected;
236 for France the current limit is 6% by volume, while in Germany and Holland it is 10% and 12%
237 respectively [40] [41].

238
239 A large EU-funded project has indicated that properly-adjusted gas-fired appliances can
240 accommodate volume concentrations of up to 20% hydrogen (given favourable natural gas quality),

241 and pipelines could transport gas mixtures containing up to 50% hydrogen (depending on the pipeline
242 steel used) [38]. Because gas consumption can vary by approximately one order of magnitude with
243 time of day, some hydrogen buffer storage may be needed within the P2G plant depending on when
244 the hydrogen is generated to ensure the concentration never exceeds 6%. However, it will not be
245 feasible to achieve an average concentration of 6% at all times, because this would require an
246 excessive amount of hydrogen storage. Therefore it was considered that average concentrations of
247 <6% should be studied.

248

249 Electrolytic hydrogen and carbon dioxide may also be used to generate synthetic methane (SNG), and
250 its injection to the natural gas grid is not restricted by permissible concentration limits. One recent
251 analysis [35] reported that hydrogen injection in the French gas grid could capture 25 TWh of excess
252 electricity per year. It predicted this growing to 75 TWh p.a. by 2050, which would require a
253 combination of SNG-injection and hydrogen-injection. For SNG, it advocated the upgrading of biogas
254 as the most cost effective route for sourcing the required CO₂. A further study [36] identified up to 13
255 TWh p.a. of excess electricity being available in France by 2030, and up to 67 TWh p.a. by 2050, which
256 must be transferred out of the power system or lost (as opposed to absorbed by P2P storage
257 technologies). The estimated requirement for P2G plant in France by 2030 was 1.2-1.4 GW, and up to
258 24 GW by 2050 [36]. The study called for 5-10% of the installed P2G capacity to be for H2I and the rest
259 for SNG injection, with the CO₂ requirement supplied entirely from bio-renewable sources.
260 Furthermore a multiple node model for power flows in NW European countries, has predicted 2030
261 curtailment levels of 5-10 TWh p.a. in each of France, Germany, Holland, Ireland and Denmark [37]. In
262 general, the studies undertaken to date provide first order estimates of excess energy levels and they
263 exclude excess nuclear - more detailed and independent predictions for future magnitudes and
264 durations of excess renewables and excess nuclear are desirable.

265 The amounts of excess energy occurring in France depend on the assumed penetration levels of
266 renewable and nuclear plant, but each of the above estimates is less than the current magnitude of
267 excess nuclear. From the gas grid perspective, the existing 6% by volume limit for hydrogen means
268 that up to about 9 TWh p.a. of hydrogen could be accommodated if appropriately administered, which
269 would require ~13 TWh p.a. of excess electricity (assuming an average electrolyser efficiency of 70%).
270 However, if excess energy is converted to SNG via the methanation of CO₂ and hydrogen, then the gas
271 grid could absorb very large amounts (e.g. potentially up to the current natural gas consumption level
272 of ~470TWh p.a.). These outline considerations frame the P2G opportunity and indicate that this
273 already available sink for excess electricity could enable France to adopt a high nuclear and high
274 renewables decarbonisation strategy, where the respective installed capacities far exceed the national
275 peak power demand.

276

277 **3.3 Storage with Reconversion to Electricity**

278 France has been identified as a European nation where the storage of large amounts of hydrogen in
279 underground caverns is geologically feasible [42]. One option is to store the hydrogen generated from
280 excess nuclear in large, geologic hydrogen stores such as salt caverns, aquifers and depleted gas fields.
281 France has a number of salt deposits it can use, mainly near its southern and eastern borders [43].
282 Aquifers are an additional option for more central regions, with existing aquifers in use for natural gas
283 storage [44]. This hydrogen could provide a seasonal buffer and be utilised by hydrogen gas turbines
284 for generating power at key times (e.g. during periods of low renewables availability when some fossil
285 fuelled power plant may otherwise be needed) [4]. This option could therefore facilitate achieving an
286 extremely low carbon footprint for French grid electricity by 2050.

287

288

289 **4. Analysis and Results**

290

291 The utilisation of excess nuclear was investigated with respect to prospective P2G and H2M objectives
292 across the period to 2050. A time series model, based on a recent hourly dataset for nuclear power
293 generation [15], was developed to analyse the effect of using electrolyzers to 'valley fill' the nuclear
294 load profiles. The analysis was undertaken with respect to average weekly and average yearly nuclear
295 load profiles (based on datasets for 2011, 2012 and 2013). A load-dependent assumption was made
296 for electrolyser system efficiency of 60 kWh/kg (66% HHV) at full-load, rising linearly to 55kWh/kg
297 (72% HHV) at 20% load. This was applied irrespective of the different pressure and purity requirements
298 of the hydrogen applications.

299

300 It is tentatively estimated that an average 5% hydrogen concentration could be reached by 2030,
301 which would require 223 kt H₂ p.a. (or an electricity input of about 12.3 TWh_e). Similarly if as predicted
302 the mobility demand reaches 598 kt H₂ p.a. by 2050 [34], the combined H2I and H2M electricity
303 requirements for electrolysis would then be ~45 TWh_e p.a. This suggests that a 2050 strategy to meet
304 all of the H2M demand plus a 5% hydrogen concentration in the gas grid would account for less than
305 half of the currently available excess nuclear electricity. Therefore SNG production could be employed
306 from the outset, in addition to H2I and H2M.

307

308 Clearly how these three respective markets develop is a function of the economic framework in which
309 the electrolyser plant operates. Economic analyses were beyond the scope of the current
310 investigation, but energy conversion processes that use electricity as the input energy are heavily
311 influenced by electricity costs; operational costs rather than capital costs can have a major influence
312 on the unit cost of electrolytic hydrogen. Of particular importance are the financial values ascribed to
313 the excess electricity that cannot be sold at the time of generation and to the balancing services
314 payments made to electrolyser operators for absorbing this electricity upon instruction. (For example
315 one recent study indicated that the use of excess renewables to power 8GW of power-to-gas
316 methanation systems injecting SNG into the UK gas grid with reconversion to power via combined
317 cycle gas turbines would be more cost effectively than building Hinkley C nuclear power station [45]).

318

319 The primary influencing variables to be considered in a further study include: the tariff paid for
320 absorbing excess nuclear electricity; the balancing services income earned from the grid operator to
321 increase or reduce load when required; the average conversion efficiency; the average utilisation
322 factor across life; plant lifetime for the required utilisation profile; maintenance costs; and any
323 incentives applied by supportive policies (such as hydrogen/SNG feed-in tariffs, or low rates of tax on
324 hydrogen fuel).

325

326

327 **4.1 Valley-Filling of Average Weekly Profiles**

328

329 The valleys in the average weekly load profile for 2013 (Figure 5) were progressively filled to achieve
330 smoother load profiles of greater load factor and annual hydrogen yields were simply extrapolated
331 from the results. Initially electrolysis was applied to fill the afternoon valleys, then increasing
332 capacities were assumed for filling deeper valleys in this load profile (Figures 6-9).

333

334 Unlike analyses based on utilising excess renewable energy, there is clearly a regular availability of
335 valleys to fill in the nuclear load profile which justifies undertaking an analysis based on the average
336 week. In practice, the actual electrolyser utilisation levels per week for a given installed capacity will
337 vary across the year, depending on how the weekly load profile varies from the average. For example
338 greater electrolyser utilisation factors would be achievable in summer.

339

340 As expected, the proposed approach results in a low electrolyser utilisation (Table 1). This is
341 influenced by periods of dormancy and significant amounts of part-load as opposed to full-load
342 operation. The part-load operation serves to improve the average conversion efficiency and extend
343 electrolyser lifetime, which tends to be determined by run-hours (or more precisely, throughput)
344 rather than a fixed number of years.

345

Installed Electrolysis Capacity (GW)	Electrolyser Energy Utilisation (%)	Electrolyser Run Time (h p.a.)	Degree of 'Valley Filling'	Hydrogen Production (kilo-tonnes H ₂ p.a.)
0.5	20	3,180	Afternoon and some overnight smoothing of nuclear load profile	16
2.0	21	5,944	Overnight smoothing of nuclear load profile	67
3.5	31	8,551	Steady nuclear load profile on weekdays	170
6.0	26	8,701	Steady nuclear load profile all week	247

346 **Table 1: Performance Summary for Various Installed Electrolyser Capacities for the Average
347 Weekly Nuclear Load Profile**

348 As expected an installed capacity of 0.5 GW of electrolysis is sufficient to fill the afternoon valley and
349 make a small contribution to filling the overnight valley (Figure 6). Electrolyser operation is
350 characterised by a demanding utilisation profile across the week, with a high number of start-ups and
351 large swings from 0 to 100% and back again. The electrolyzers will start up twice daily, operate mainly
352 at part load at a low average utilisation of 20%, and make only a modest contribution towards meeting
353 future hydrogen demands (16 kt p.a.). Note these values may be slight overestimates as they are
354 based on averaged data (e.g. 0.5 GW will not be sufficient to fill the afternoon valleys on some days
355 when the valley depth reaches 1 GW). Counteracting this, however, is the ability of an electrolyser to
356 accept loads significantly greater than its nominal capacity for brief periods; when applied to real-time
357 data this overloading capability can allow utilisation and production levels to exceed (if desired) those
358 reported in Table 1.

359

360 Increasing the installed capacity of electrolysis to 2.0 GW would be sufficient to smooth substantially
361 the nuclear load profile on weekdays (Figure 7) and will enable a step in hydrogen production from 16
362 to 67 kt p.a., which is roughly equivalent to the 2030 H2M demand. As the installed capacity is
363 increased further to 3.5GW, the hydrogen yield becomes more significant and the annual run time
364 increases substantially (Table 1). The required electrolyser technology will therefore need to be 'on'
365 for much of the year (reducing the number of start-ups) but operate mainly at part-load (Figures 8 and
366 9). However, it will be challenging economically to progress from an installed capacity of 3.5GW
367 operating at a utilisation factor of 31% to one of 6.0 GW operating at 26% utilisation. This suggests
368 that supportive government policies will be required if the considered approach is to progressively
369 step up its annual hydrogen yield.

370

371 To achieve a flat load profile across an average week, about 6 GW of electrolysis would be required
372 (Figure 9). This would yield almost sufficient hydrogen annually to meet both the 2030 H2M demand
373 and a 5% hydrogen concentration in the gas grid (Table 1). It would appear therefore that the
374 operation of up to 6 GW of electrolysis in France by 2030 in the described manner would be a good
375 strategy for meeting the predicted 2030 H2M and H2I requirements *and* valley fill the average weekly
376 nuclear generation profile. This could be achieved by deploying several hundred electrolyser-HRS and
377 P2G systems.

378

379 However, 6 GW of electrolysis with an average utilisation of 26% will only capture about 13.5 TWh of
380 the available excess nuclear. A more ambitious strategy based on valley-filling the annual profile is
381 needed if greater use of excess nuclear is to be achieved.

382

383

384 **4.2 Valley-Filling of Annual Profiles**

385 The 'valley' in the annual load profile is much deeper and wider than those occurring in the average
386 weekly profiles. Figure 3 suggests that an installed capacity of approximately 20 GW would be required
387 to valley-fill the annual profile. Therefore the model was adjusted to consider greater installed
388 capacities of electrolyzers. It was found that a 20 GW implementation operating at an average
389 utilisation of 66% could capture about 115 TWh of excess nuclear and generate 2,050 kt p.a. of
390 hydrogen. This would easily satisfy the 2050 H2M requirement and so may be considered as a major
391 pathway for satisfying the hydrogen mobility demand. Furthermore, in addition, a 5% hydrogen
392 concentration in the gas grid could be achieved, while still leaving the majority of the hydrogen
393 production for generating SNG (Figure 10).

394

395 Approximately 33 TWh p.a. of SNG could be produced in this manner, which is sufficient to reduce
396 France's current annual natural gas consumption by 6.9%. There is a seasonal trend in SNG production
397 (Figures 10 and 11), which suggests it could displace up to 40% of the current natural gas use in the
398 summer months, while making only a very modest contribution in winter. Despite having a large
399 electrolyser capacity in the power system, the effect of hydrogen and SNG upon the gas system will
400 be small (Figure 11). Hence P2G approaches utilising excess nuclear may best be considered as
401 contributors to assisting gas-grid decarbonisation (analogous to bio-methane injection) rather than as
402 a major solution.

403

404 Figure 12 provides an illustratory roll out scenario for the power-to-gas and hydrogen mobility
405 applications across the period to 2050. Some combination of hydrogen use for mobility (high value)
406 and in the gas grid (lower value) is projected, but the relative amounts will of course depend on
407 economic criteria that define the market framework. Stakeholders and policymakers still need to
408 agree the remuneration framework for synthetic gas injection and targets for capturing rather than
409 wasting excess energy. However, it is clear that excess nuclear could serve to meet the entire
410 hydrogen requirement of the predicted 2050 FCEV market, whilst contributing both a useful hydrogen
411 concentration plus a substantial input of SNG to the gas grid (Fig. 12).

412

413

414 **5. Conclusions**

415

416 Increased utilisation of existing nuclear power plant, rather than turning plant down during low
417 demand periods, presents a substantial untapped source of low-carbon energy in France. It may be
418 applied to meeting the future demand for hydrogen mobility and for reducing dependency on
419 importing fossil fuels via power-to-gas by controlling electrolyser operation to 'valley fill' the nuclear
420 load profile. The proposed approach warrants a very low unit price for electricity, because it provides
421 a service that absorbs otherwise unsaleable electricity.

422

423 A progressive deployment of electrolyzers that reaches 20 GW by 2050 is identified as being a most
424 expedient implementation for utilising excess nuclear electricity. A deployment of about 6 GW by 2030
425 would substantially flatten the average weekly load profile placed on existing nuclear plant, and so
426 simplify operation and maximise the return on investment. It would provide sufficient fuel to easily
427 meet the predicted hydrogen mobility requirement and make a significant contribution to the gas

428 sector. Annual hydrogen yields may be augmented further by absorbing excess renewable power
429 when it occurs out of time phase with excess nuclear.

430
431 The identified electrolyser operating profiles for absorbing excess nuclear electricity exhibit
432 characteristically low utilisation factors with substantial periods spent at part load. This requires fast-
433 responding electrolyser technology and should yield greater average conversion efficiencies and
434 electrolyser life expectancies. Further research should address the techno-economic case for
435 implementation, with consideration given to input electricity costs, balancing services income, the
436 effects of low utilisation on system life, load-dependent conversion efficiency, overloading at high
437 current density for restricted periods to reduce capital costs, the influence of hydrogen feed-in tariffs,
438 hydrogen taxation levels, the temporal coincidence of excess nuclear and excess renewables and the
439 opportunity to increase utilisation by absorbing both for the period to 2050.

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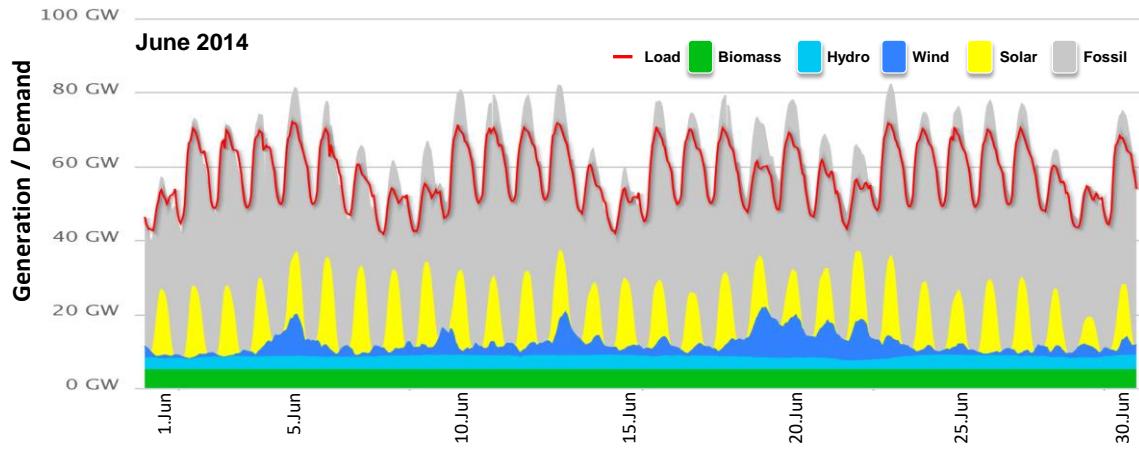
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445 **Figures**



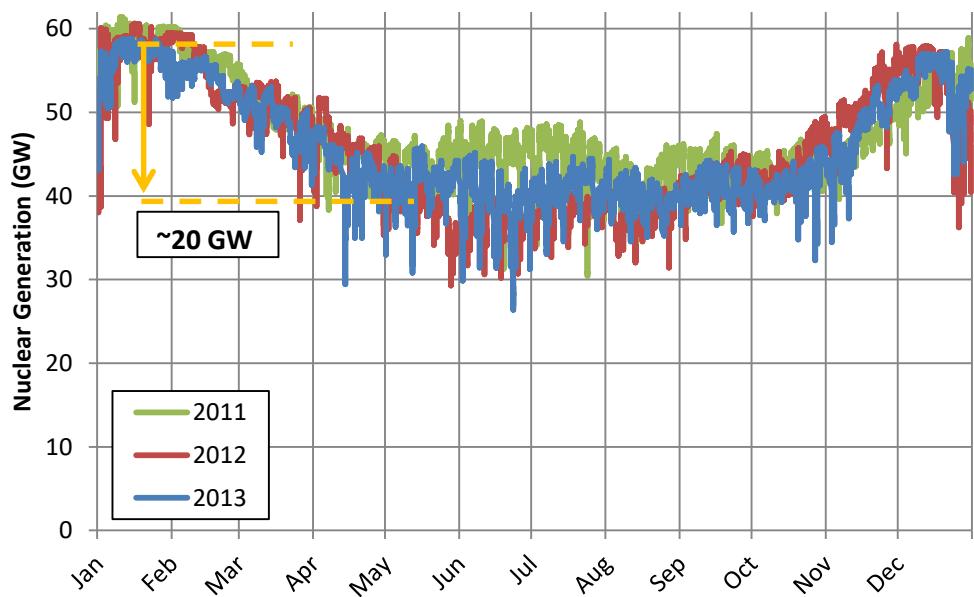
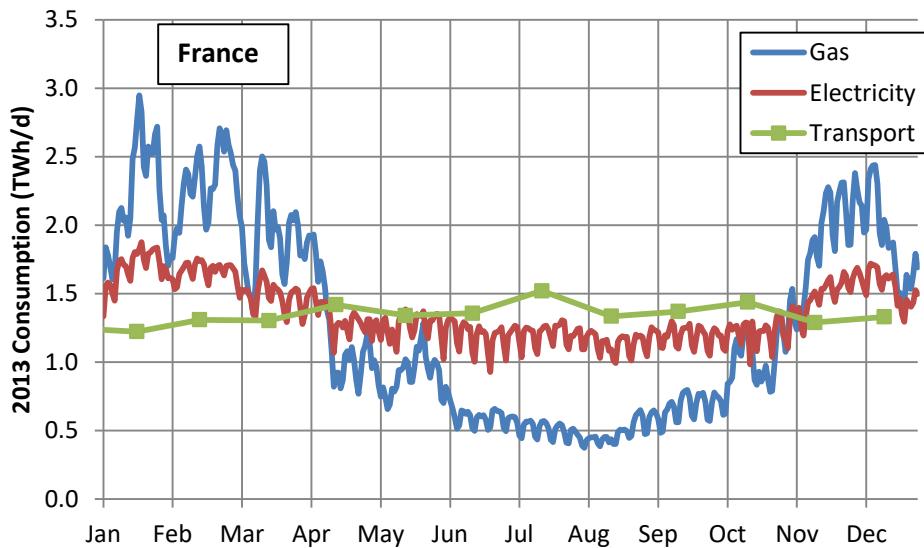
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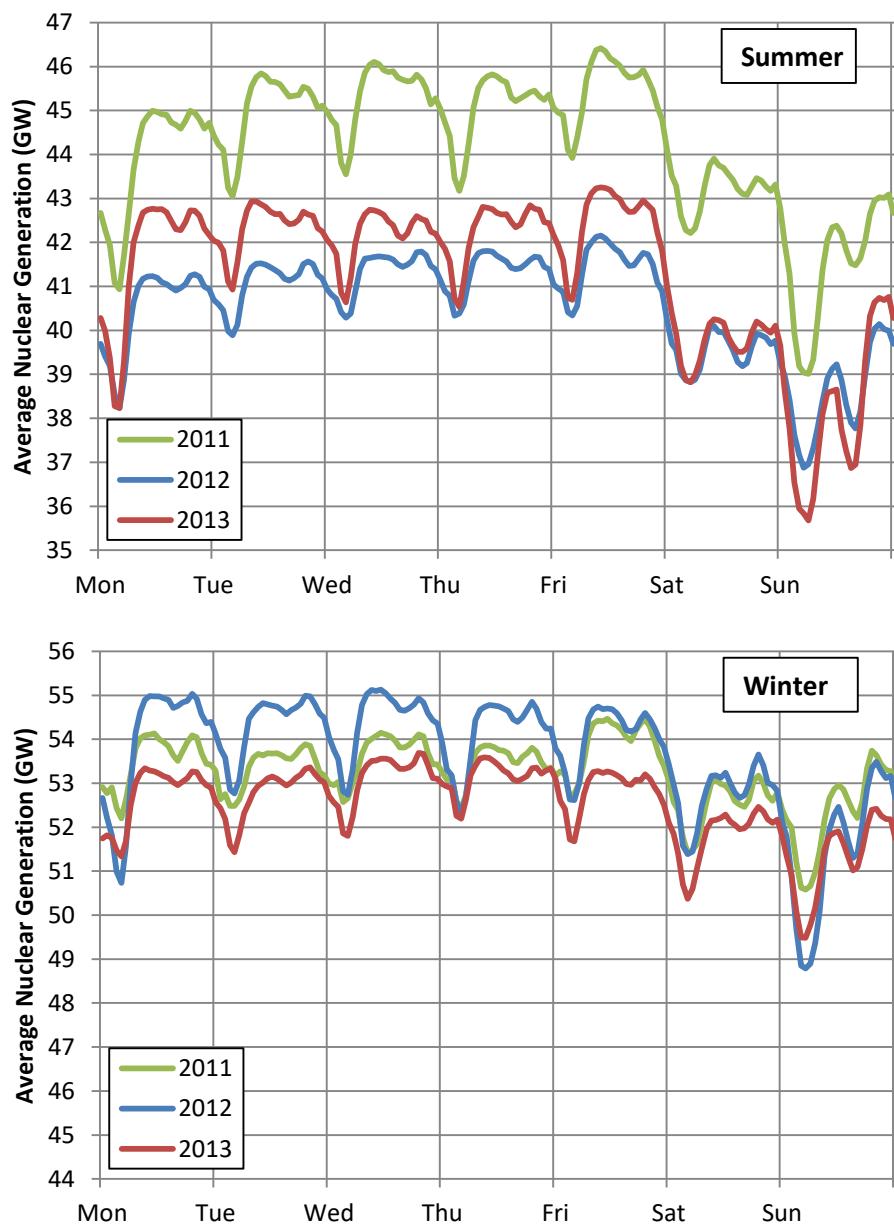
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448 **Figure 1: Solar power in Germany causing excess energy to be exported to neighbouring countries**
449 **or curtailed [13]**

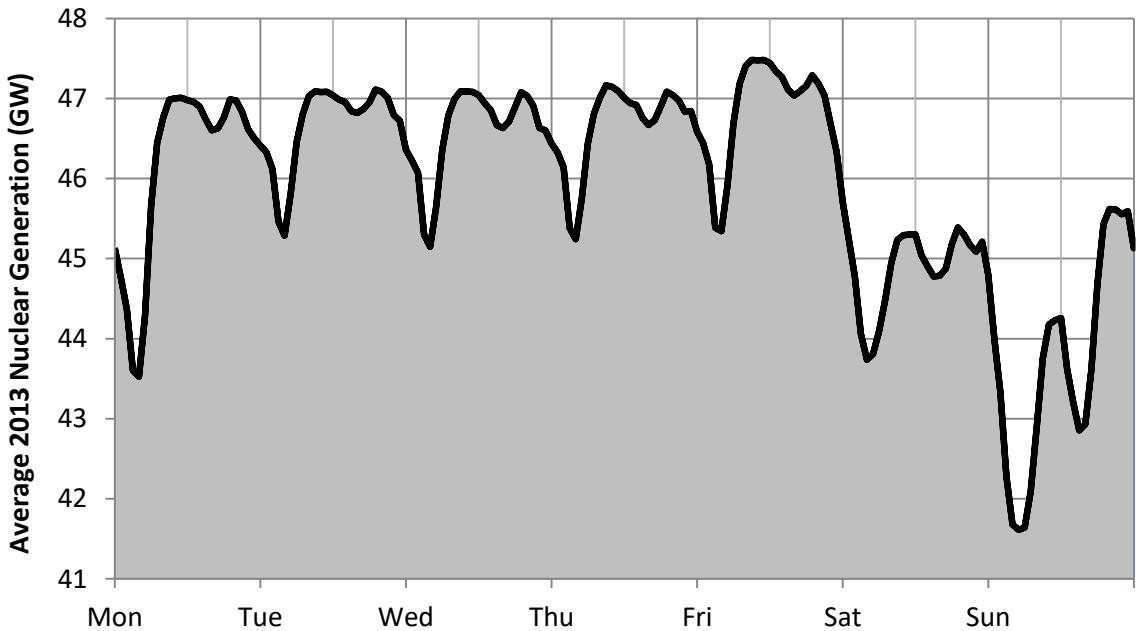
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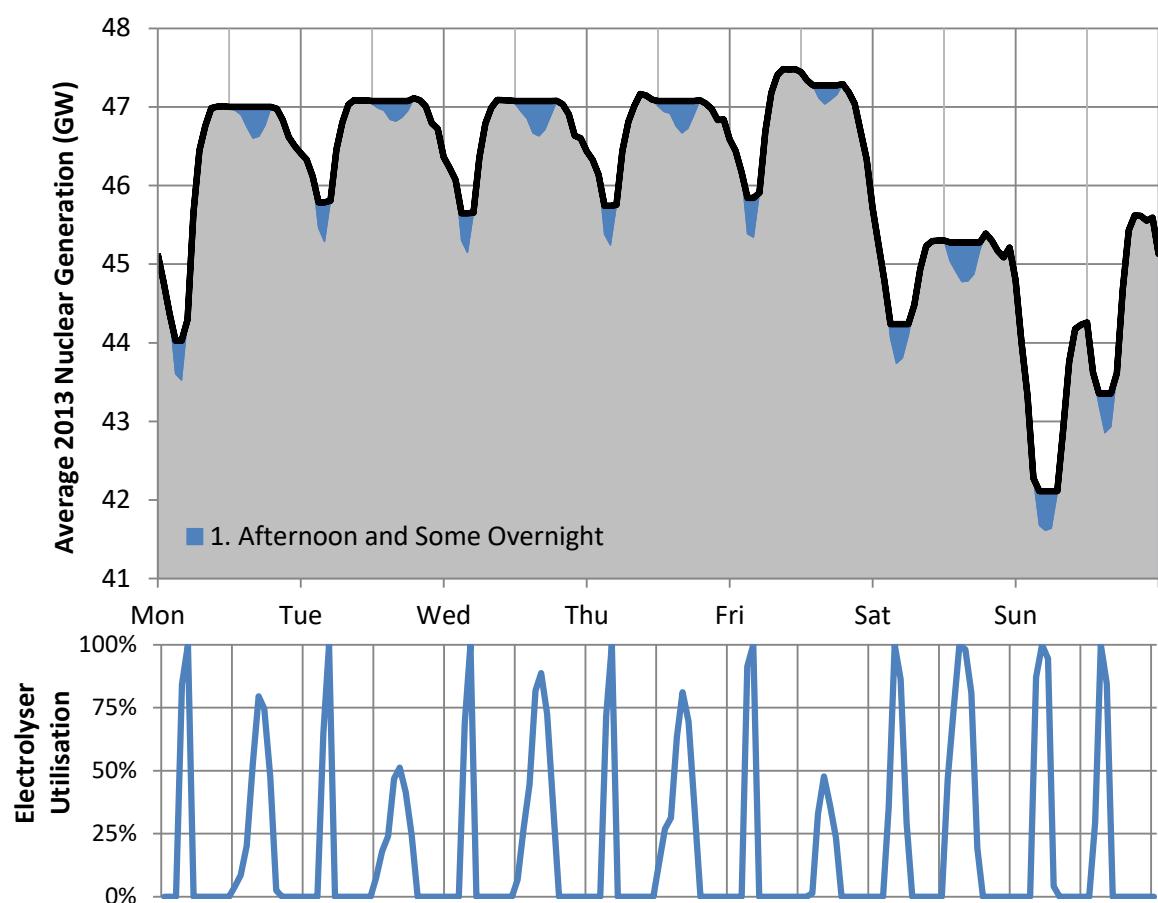




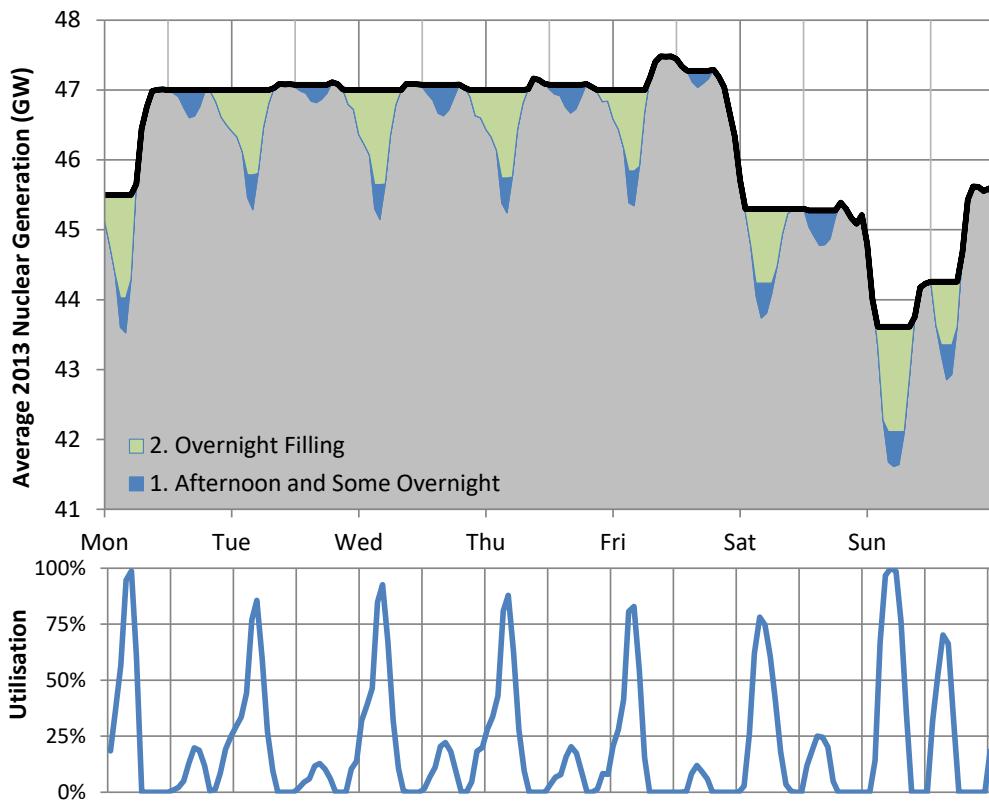
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459 **Figure 4: Average Summer and Winter Week Nuclear Power Generation Profiles in France [15]**
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463 **Figure 5: Average Weekly Profile of Nuclear Production in France [15]**

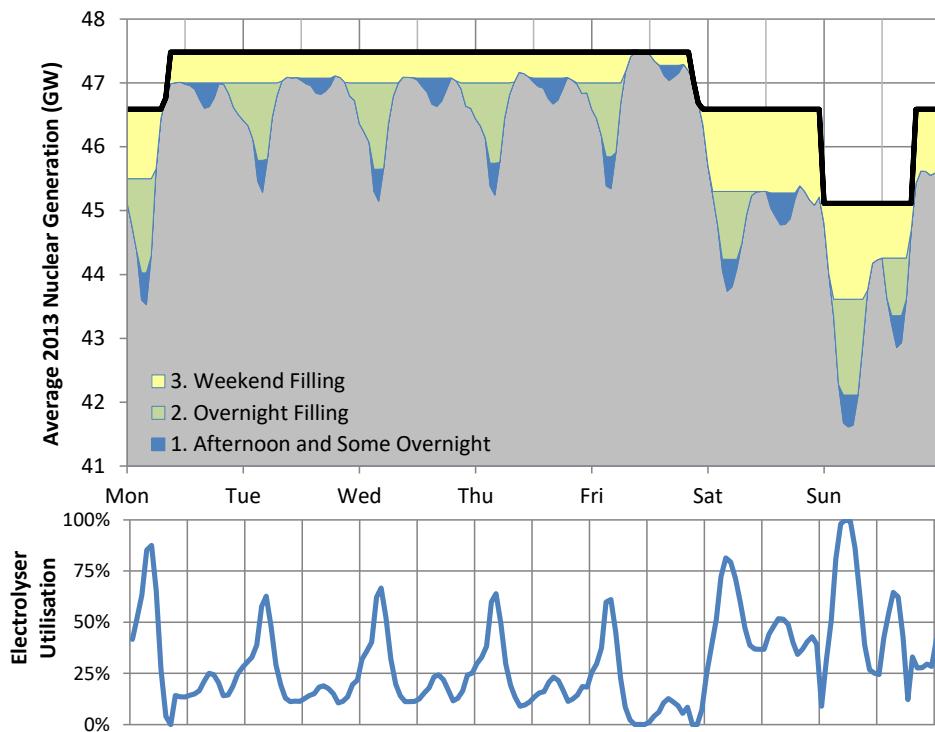


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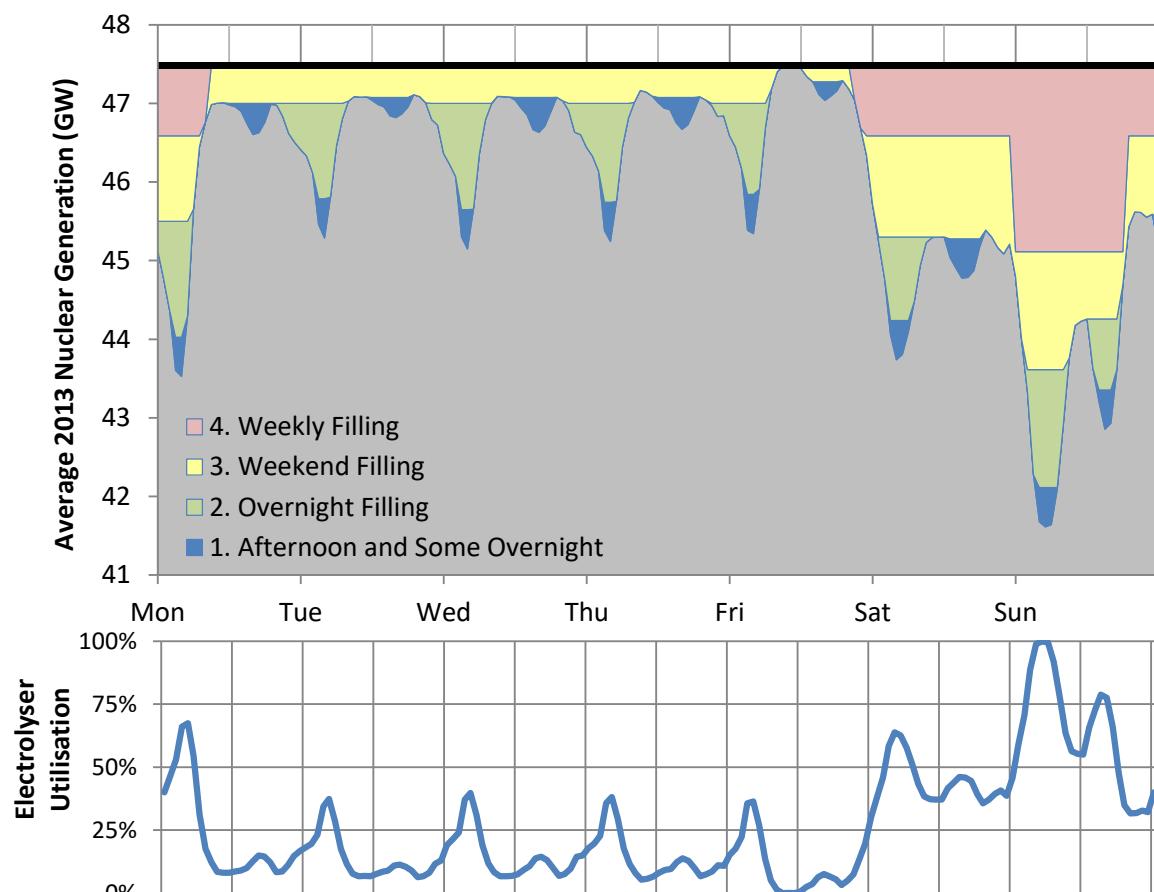
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471 **Figure 7: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 2.0GW of**
472 **Electrolysis**

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476 **Figure 8: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 3.5GW of**
477 **Electrolysis**

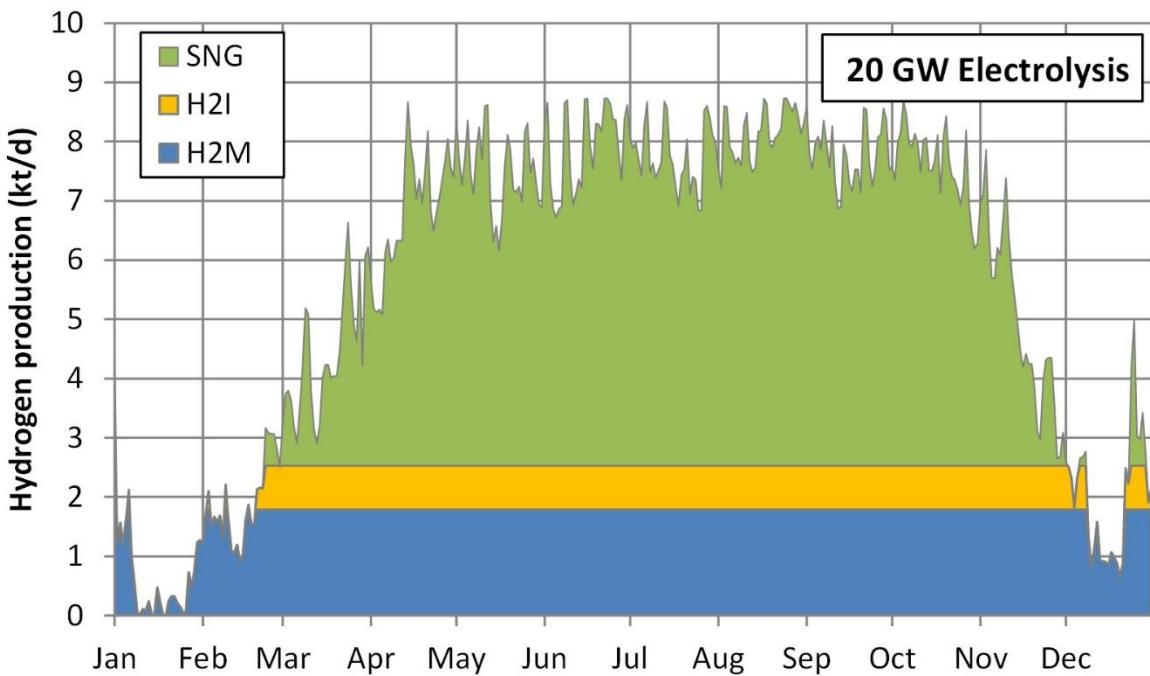
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481 **Figure 9: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 6.0GW of**
482 **Electrolysis**

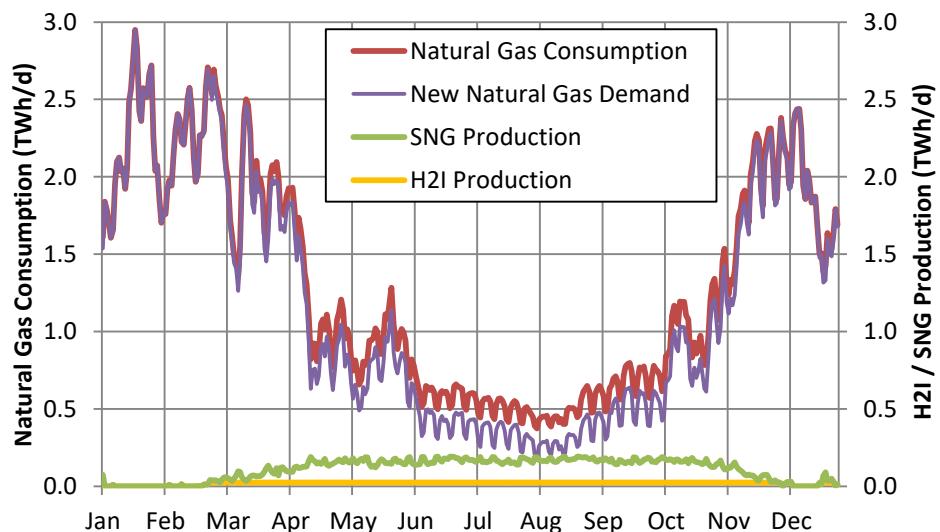
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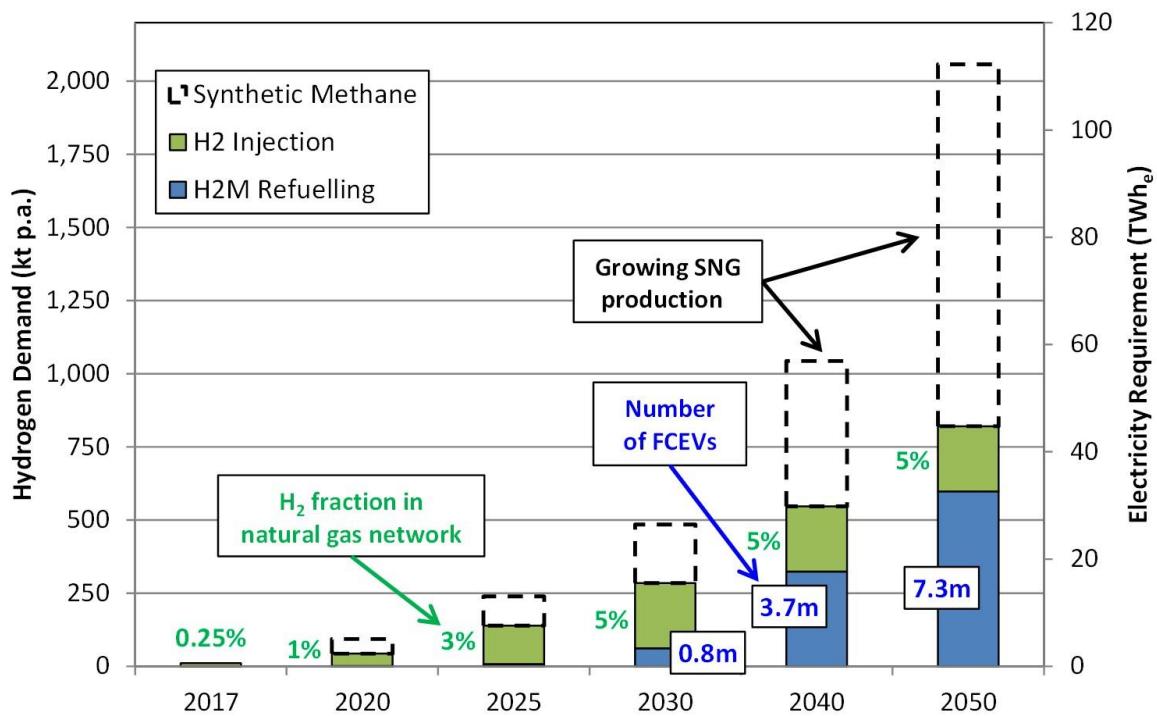
485 **Figure 10: Operation of 20 GW of electrolysis to valley fill the 2013 nuclear generation profile**

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488 **Figure 11: The effects of hydrogen and SNG injection as shown in Figure 10 on the 2013 demand**
489 **profile for natural gas**



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492 **Figure 12: Applying Excess Nuclear Electricity to Hydrogen Mobility and Power-to-Gas Applications**

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