Nuclear Power for Carbon-Free Hydrogen Production Through High-Temperature Steam Electrolysis

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Abstract

In this paper I calculate a cost estimate for the production of hydrogen through high-temperature steam electrolysis powered by a nuclear plant, specifically a high-temperature gas reactor. This cost estimate is based on reactors built and operated at a commercial scale and thus presents a historically based cost figure to complement existing cost estimates in the literature which rely on hypothetical plant designs. I examine different ways of coupling nuclear power to a hydrogen production plant and compare the resulting costs to those of existing hydrogen production methods.

1 Introduction

The uses of molecular hydrogen (H_2) range from industrial processes to energy storage. Hydrogen is used for steel production, which is essential to a large part of industry; it produces ammonia through the Haber-Bosch process, which creates fertilizer necessary for feeding billions of people; and it has been proposed as an energy storage technology since its energy density on a mass basis is higher than fuels such as liquefied natural gas, gasoline, or other non-CO_2-emitting energy storage such as lithium-ion batteries. [Int19]

Currently, hydrogen is produced primarily through steam methane reforming in the U.S.; globally, coal gasification and oil reforming are also used. For steam methane reforming, typically the methane source is natural gas; landfill gas (biogas), biofuels, and petroleum fuels are also used to a small degree.

Steam methane reforming decreases CO_2 emissions somewhat and CO emissions significantly compared to burning natural gas directly for the equivalent amount of energy. However, this process still accounts for 3% of global industrial CO_2 emissions. [SRD14] Thus, national entities around the world including the EU, China, and Japan have expressed interest in and commitment to producing H_2 using non-CO_2-emitting energy sources.

These technologies do exist, but they currently cost much more than steam methane reforming even with carbon capture and storage (CCS) implemented, as seen in Figure 1. Some estimates for the cost of carbon-free hydrogen several decades into the future suggest that renewable methods of producing hydrogen may become cost-competitive by 2060, predicated mostly upon an expected decrease in the cost of renewable energy and increase in electrolyzer efficiency. (Almost all proposed carbon-free methods of hydrogen production rely upon water electrolysis, which will be discussed in Section 2.1 as it applies to nuclear power.)

What about nuclear power as a candidate for the source of energy for clean hydrogen production? Currently, many studies suggest that the cost of hydrogen produced using electricity and/or heat generated by a nuclear power plant to run electrolysis is within the cost range for green hydrogen using renewable energy. Nuclear power boasts one great advantage over renewable energy: nuclear plants in the U.S. have the highest capacity factor of any energy source, at 93% in 2023, whereas renewables suffer from the problem of diurnal and seasonal intermittency. In addition, nuclear plants may be better suited to applications that require some form of input heat: for example, providing the heat for the SMR process or for certain thermochemical cycles that produce H_2 directly.

In this paper, I will focus on the potential for nuclear power to supplement hydrogen production by powering a high-temperature steam electrolysis process, which is similar to the water electrolysis processes powered by renewable sources except that it occurs at a higher temperature, raising its efficiency. Cost estimates for this process exist in the literature, but many of them rely on hypothetical plant designs or estimate costs for reactors which have not been built in decades in line with current reactor prices. I derive a cost estimate, using the Hydrogen Economic Evaluation Program (HEEP) code [KM10] provided by the IAEA, which is a direct extrapolation of the cost of an actually built commercial-scale reactor, the THTR-300, to the application of hydrogen production today in the U.S. Once this cost estimate is made, I examine several design possibilities for the reactor and compare to the price of green hydrogen today. These comparisons offer some additional insight as to whether this method of hydrogen production could be feasible or is worth investing in.

2 Proposed methods for hydrogen production from nuclear power

2.1 Water electrolysis

Water electrolysis is one way to produce hydrogen, in which a direct electric current causes water to split into molecular oxygen and hydrogen. Several different electrolyte materials

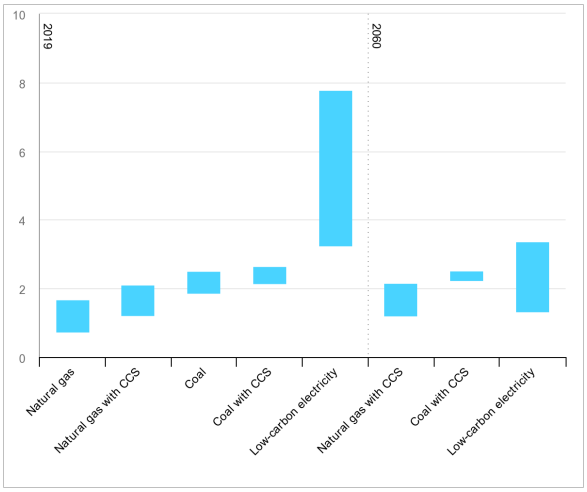

Figure 1: Global average levelized cost of hydrogen production in USD/kg by energy source and technology, 2019 and 2060 (projected). [Int19]

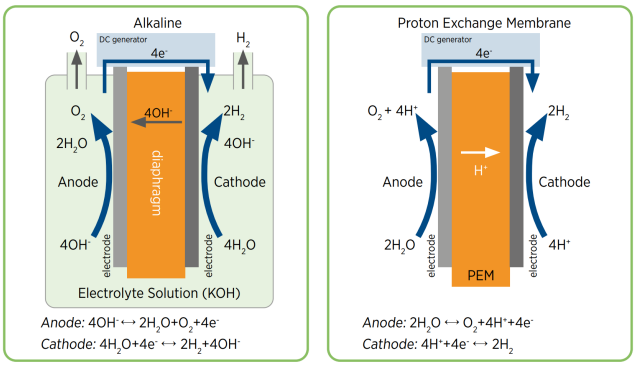

Figure 2: Electrolysis cell diagrams for the PEM and alkaline electrolyzers. [TBMC20]

and system designs can be employed to accomplish this, but they operate under the same general principle.

In all cases, the overall system can be seen as two main parts: the electrolyzer stack, containing a series of cells in which the actual electrolysis reaction takes place; and the balance of plant, which comprises the rest of the system, including the input power, water supply, etc. Essentially, some power source produces a voltage between the cathode and anode of a cell inside the electrolyzer stack.

As water reaches the electrodes, it is split into ions such as H^+ and OH^- (the exact half-reactions differ between electrolyzer types), which separate and travel through the intervening electrolyte to the corresponding cathode or anode. A membrane between the electrodes also keeps the resulting H_2 and O_2 gases separated. The cell schematic for water electrolysis with two types of electrolyzers is shown in Figure 2. [TBMC20]

2.1.1 Low-temperature electrolysis

Polymer electrolyte membrane (PEM) electrolyzers and alkaline electrolyzers are two technologies which perform water electrolysis to produce hydrogen, each functioning at a temperature range from below 100°C up to 200°C. [GEEZ22] These electrolyzers are currently used in efforts to power hydrogen production through solar [HGTSH23] or wind energy.

Since these electrolyzers also fundamentally function by zapping water at near-boiling or above-boiling temperatures with electricity, nuclear power could be used to power this relatively well-established method. However, the relatively low temperature at which this process occurs results in decreased ionic conductivity and thus lower efficiency; low-temperature electrolysis thus needs greater electrical input than high-temperature electrolysis to achieve the same voltage. [GEEZ22] Nuclear plant thermal efficiency hovers around 33%, meaning one unit of heat is three times cheaper than one unit of electricity. So there is good reason to consider the possibility that a method such as high-temperature electrolysis, which requires more heat and less electricity to achieve the same voltage as low-temperature electrolysis (discussed shortly), may be more fitting for nuclear power.

In addition, the most effective catalysts for PEM electrolyzers (currently the more commonly used or proposed type for carbon-free hydrogen production) are made of iridium, the least abundant naturally-occurring element on Earth; this is a large contributor to the cost. [KKT+23]

2.1.2 High-temperature electrolysis

Using a solid oxide electrolyzer, the water electrolysis reaction can be performed at temperatures between 500°C-1000°C. This increased temperature causes the efficiency of the reaction to increase; i.e., to achieve a given desired current density of electrolysis, a lower cell voltage is needed using solid oxide electrolysis vs. the other methods mentioned. However, the high temperatures cause electrodes to degrade faster than using other methods. Recent advances in materials engineering have brought solid oxide electrolysis closer to being feasible for long-term usage, but there has been no at-scale demonstration yet. [Leo21]

If the reactor provides both electricity and heat to the electrolysis process, as proposed in most setups, the flow of the coolant is separated into two parts: one part of the coolant flows in a power-cycle loop which produces electric power as usual for the reactor and then pre-heats the electrolysis gas mixture; the remaining coolant flows through the intermediate heat exchanger, which performs final heating to the electrolysis operating temperature.[WHL+15, O'B10] This final heating occurs after a recuperator, which gathers low-grade, post-electrolysis heat, heats the input water stream such that it vaporizes to steam. An example of this setup can be seen in Figure 3. The actual proportion of coolant directed towards the power-cycle loop vs. the intermediate heat exchanger varies based on need. In an INL study, over 90% of coolant was used for the power-cycle loop.[O'B10] A more recent review of HTE technologies concluded that "for HTSE operating at around 700°C, heat re-

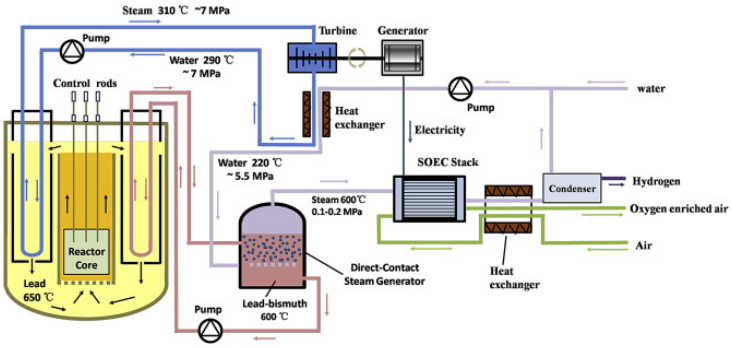

Figure 3: Proposed design for lead-cooled reactor [WHL+15]

sembles around 25% of the total energy input." [FVOEEAH23] For industrial-scale HTSE processes, I use a split of approximately 80:20, with the exact ratio as given in Prosser (2023), which evaluated the costs of running a "generic" solid-oxide electrolyte hydrogen production plant. [P+23]

2.2 Thermochemical cycles

Another option for hydrogen production from nuclear power is using heat to run a thermochemical cycle, e.g. through a sulfur-iodine cycle or hybrid sulfur cycle. [GEEZ22] In fact, there is some evidence that this method could be cheaper than using high-temperature electrolysis. [OEE14] In this paper I focus on high-temperature electrolysis due to the relative simplicity of the process. However, this should not be construed as a suggestion that high-temperature electrolysis is a better candidate for nuclear-powered hydrogen production than a thermochemical cycle.

3 Existing cost-benefit analyses

A number of existing studies have made estimates for how much it would cost to produce hydrogen using high-temperature steam electrolysis with nuclear power as the energy source. The results are shown in Table 1, with discussion to follow. It is also viable to produce hydrogen from renewable energy sources such as wind or solar; this is known as "green hydrogen". Its prices are shown in Table 2.

For reference, the LCOE of hydrogen production by natural gas ranges from \$0.7-\$1.6 per kg, or from \$1.2-\$2.1 per kg if carbon capture and storage is included. [Int19]

3.1 Pricing historical VHTR and HTGR designs

On what basis and with what methodology are these estimates performed? The energy sources considered in the studies below are Very High Temperature Reactors (VHTRs) and High-Temperature Gas-cooled Reactors (HTGRs). Yang et al. [YL08] and the INL [O'B10] consider VHTRs as their energy source; the VHTR is a Generation IV reactor design which has not been built yet, so the costs and plant parameters reported in this publication have not yet been demonstrated. This also means there is no historical data on realistic values for operating and maintenance costs.

On the other hand, a different INL study and the IAEA [EEK17] consider the HTGR as their energy source, which has been built before. HTGRs use helium gas as a coolant; graphite as a moderator, either in prismatic blocks or in pebbles; and coated fuel particles as the fuel. These reactors have been designed for passive safety effects: helium is chemically inert and exists in a single phase; graphite has a large heat capacity. [Int01]

The HTGR is the only reactor that has at present already been constructed whose outflow coolant is at a high enough temperature to provide process heat for HTSE. (The temperature range of liquid metal cooled reactors has some overlap with the temperature range needed for HTSE, but often it is not considered a viable candidate as the margin is quite small.) [EEO19]

The operating temperature for a solid-oxide electrode ranges between 500°C-1000°C, but usually operation is done between 700°C-900°C, [FVOEEAH23] while the gas outlet temperature of a high-temperature gas reactor is 750°C for the reactor I consider below, well within the operating range. [SKK+74, U.S72]

To date, three HTGRs have been built and operated on a commercial scale: Peach Bottom Unit 1, Fort St. Vrain, and the Thorium Hocktemperatur Reaktor. [BP11] I choose to focus on the Thorium Hocktemperatur Reaktor, or THTR-300, since it was the most recently constructed and performed the best in terms of reliability, so a reactor today would most likely follow THTR-300's design most closely.

More modern research reactors exist that have been constructed in China and Japan and are currently operational. [BP11] However, their construction and operation costs are substantially different than those in the U.S. or Europe due to different labor costs and regulatory processes; this factor combined with the small size of the research reactor makes them too distinct from our desired reactors to be considered as a rigorous comparison here.

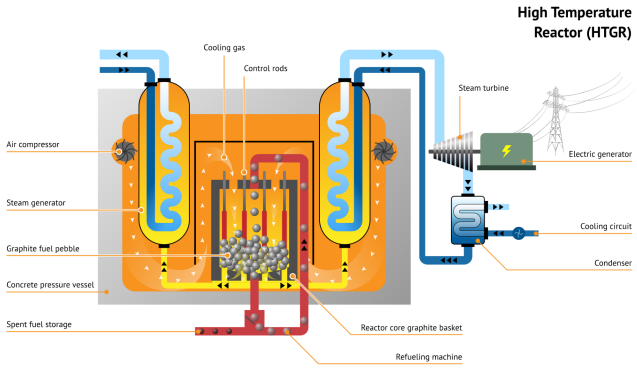

Figure 4: High-temperature gas-cooled reactor diagram. [Ene23a]

Table 1: Summary of reported hydrogen cost produced using nuclear energy.

Study	Energy Source	Hydrogen Technology	H_2 Cost ($/kg)
Yang et al. [YL08]	VHTR	HTSE	4.19-5.42
Idaho National Laboratory [O'B10]	VHTR	HTSE	5.64
Idaho National Laboratory [Lab10]	HTGR	HTSE	6.73-7.31
IAEA [EEK17]	HTGR	HTSE	3.45

Table 2: Summary of reported green hydrogen cost.

Study	Energy Source	Production Route	H_2 Cost (2023$/kg)
Lazard (2023) [BS23]	Renewable energy from grid	PEM electrolysis	4.77-7.37
Lazard (2023) [BS23]	Renewable energy from grid	Alkaline electrolysis	3.79-5.78
IRENA (2020) [TBMC20]	Onshore wind	Electrolysis	3-6
IEA (2019) [Int19]	Renewable energy from grid	Electrolysis	4.05-9.74

3.1.1 Thorium Hocktemperatur Reaktor

Constructed between 1971-1984, this reactor implemented some passive safety features and ran into only a few technical difficulties which were resolved quickly, but was still decommissioned early in 1991 [PRI23] due to sociopolitical reasons. The long construction period, due to changing regulations and licensing requirements, resulted in reactor construction dramatically exceeding its initial cost estimate of 710 million DM, for a total cost of 4 billion DM in 1984 [BKR+90, WBS84]. The need for early decommissioning was not foreseen, so there was no pre-planning phase and decommissioning costs were ultimately significantly higher than predicted, reaching 773.5 million DM in 1997. [DNR97]

3.1.2 Applicability to the modern day

Some aspects of reactor cost would change from their historical values if considered for the present day. I address the following elements of cost:

Construction period and capital cost. Construction times have increased to a global median of 7.5 years for reactors connected to the grid in 2022 [Wor23]; as for the U.S., the only two reactors constructed in the past 20 years have taken a continuous time of 21 years and 14 years to construct. [FHJ23] The IAEA's HEEP code [KM10] used in this paper only allows construction times up to 10 years, however; so I assume a 10-year construction duration.

The total cost of construction was 4 billion DM; today, the overnight cost would be 3.4 billion USD (see the Appendix for details on this figure).

Decommissioning cost. THTR-300 had a lengthy and expensive decommissioning process due in part to the lack of planning towards decommissioning. The fact that it was one of the first HTGRs to be built likely also played a role. I will assume a 10% decommissioning cost today, which is around

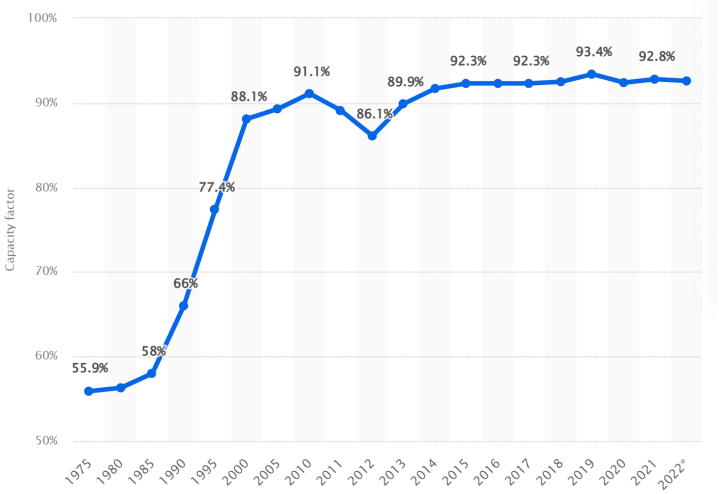

Figure 5: Average capacity factor of reactors in the U.S. over the years. [Ene23b]

average for modern reactors.

Operational period. The short period of operation of this plant before being decommissioned is neither ideal nor common in recent times: the average age of the 93 currently operating nuclear reactors in the U.S. is 42 years, and only 22 reactors are in a state of decommissioning. [EIA23] Assuming that a reactor will run for about 40 years is thus appropriate.

Availability factor. THTR-300's capacity factor over its lifetime was around 60%. [BKR+90] This figure has improved uniformly across U.S. reactors since the 1970s-80s, when THTR-300 was constructed, as seen in Figure 5.

Fuel cost. THTR used a fuel cycle involving balls of thorium and highly enriched uranium (HEU) as fuel. Today, high-temperature gas reactors overwhelmingly use LEU (low-enriched uranium) UO_2; this is the fuel type used in both the currently

operating Japanese and Chinese research HTGRs.

Despite its effectiveness, the thorium/HEU cycle was never developed commercially due primarily to the shift to LWR infrastructure and the development of fuel types to support it. Today, the thorium/HEU cycle would likely not be revived, partly due to proliferation concerns and partly due to the difficulty of recycling some highly radioactive thorium fission products. [Int10]

Instead, I use a recent estimate for the cost of a TRISO fuel cycle, $2.04 per GJ of thermal energy production. [SVLWS21]

$$\frac{\$2.04}{1e9\text{ J}} \times \frac{760e6\text{ J}}{1\text{ s}} \times \frac{3.15e7\text{ s}}{1\text{ year}} \times 0.9 = 52.6\text{M USD per year}$$

3.2 Pricing electrolysis

I base all estimates of hydrogen plant cost on Prosser (2023) [P+23], which provides a comprehensive calculation of costs for the whole solid oxide electrolysis stack and balance of plant. The overall SOEC hydrogen plant efficiency at 750°C is 36.2 kWhe per kg of H_2 produced, a better efficiency than the range of 40-50 kWhe/kg H_2 which applies to SOEC systems at present. While solid oxide electrolyte efficiency is projected to increase in the coming years, the actual rate of increase is unclear and some analyses simply put their estimate of SOEC efficiency at ¡40 kWhe/kg H_2 by 2050, [ele] so Prosser's estimate should be treated as an upper bound on efficiency for at least several decades (encompassing the length of time considered in this paper).

The lifetime of a typical electrolysis plant is only around 20 years whereas the lifetime of a nuclear plant is 40 years. In fact, the lifetime of a solid oxide electrolyzer stack is currently less than 5 years due to more rapid degradation of materials at higher temperatures. Given the progress in solid oxide electrolyzer development, by 2050 this is projected to reach the 20 years of a mature electrolysis technology. [ele]

To roughly account for this, I spread the capital cost of an additional hydrogen plant over the desired 40 years of operation as refurbishment costs (counted in O&M). Rather than the baseline yearly O&M cost being 20% of capital cost, as provided by the IAEA for a HTSE plant and supported by Prosser [KM10, P+23], I use 22.5%. While this is a more realistic scenario than, say, simply doubling the capital cost of the H_2 plant (which corresponds to building two plants and turning on the second one when the first one expires), it is unlikely that any maintenance/building costs would actually be spread evenly over the 40-year period, so this is a simplification due partly to limitations of HEEP regarding construction/O&M timelines.

4 Cost studies

Using the Hydrogen Economic Evaluation Program (HEEP) code [KM10] provided by the IAEA to run a cost study on these parameters, I find estimates for hydrogen production cost in three scenarios. The input parameters are listed in Table 4. Financial inputs are listed in Table 3 and reflect the current rates relevant to the 2023 economy.

The three scenarios are detailed below:

NPP Heat + 100% Electricity. In this case, the nuclear plant provides all of the heat and all of the electricity input to the SOEC plant. The SOEC plant takes about a 4:1 electricity-heat energy split, which is satisfied by directing most coolant through the power cycle to produce electricity and having the remaining coolant generate heat only.

NPP Heat + 50% Electricity. To investigate whether costs could be lowered by incorporating some electricity from an external source so that the nuclear plant can output a higher proportion of heat (which is cheaper, as discussed in Section 2.1), this scenario assumes that the nuclear plant provides only 50% of the needed electricity and the rest is drawn from a co-located wind or solar farm. (All renewable sources considered in this paper are assumed co-located with the nuclear/hydrogen plant to minimize transmission line costs.)

The LCOE, capacity factor, electricity cost, and HEEP results are provided as ranges in Table 4. [EIA22] These ranges correspond to electricity from solar at the lowest capacity factor recorded in the U.S. in 2022, 12.3% [sol]; and electricity from wind at the highest capacity factor recorded in the U.S. in 2022, 52%. [win] The listed capacity factor in the table is the overall capacity factor for the SOEC plant, taking its baseline availability to be 90%. All possible values for these outputs which result from building either solar or wind fall inside the presented range.

NPP Heat Only. In this case, the nuclear plant only provides heat to the SOEC plant; all electricity comes from a co-located wind or solar farm. The ranges in capacity factor, LCOE, etc. correspond to the same spread of inputs as discussed for the 50% electricity case.

For each scenario, the size of the SOEC facility is scaled such that it accepts the appropriate amount of energy from the nuclear plant. This is a simple linear scaling, consistent with Prosser's model which does not find a significant effect from economies of scale. One could also conceive of building a smaller nuclear plant instead of building a 3000-MW electrolysis plant, but I chose to scale the SOEC plant instead so that all numbers from THTR-300 could be used directly.

Table 3: Finance Details

Parameter	Value
Discount rate (%)	9.7
Inflation rate (%)	3.2
Equity : Debt (%)	60 : 40
Borrowing interest (%)	7
Tax Rate (%)	21
Depreciation period (yrs)	40

Table 4: Combined Energy Plant Details

Parameter	NPP Heat + 100% Electricity	NPP Heat + 50% Electricity	NPP Heat Only
Nuclear Power Plant Details			
Thermal rating (MWth)	760	760	760
Heat for H2 plant (MWth)	63	116	760
Electricity rating (MWe)	296	296	0
Overnight Capital cost (USD/unit)	3.40E+09	3.40E+09	2.55E+09
Fuel cost (USD/yr)	5.26E+07	5.26E+07	5.26E+07
O&M cost (% of capital cost)	5.7	5.7	5.7
Decommissioning cost (% of capital cost)	10	10	10
Hydrogen Generation Plant Details			
H2 generation per unit (kg/yr)	6.96E+07	1.28E+08	8.40E+08
Heat consumption (MWth)	63	116	760
Electricity required (MWe)	271	500	3275
Overnight Capital cost (USD)	2.53E+08	4.66E+08	3.05E+09
LCOE (USD/kWh)		0.036-0.040	0.036-0.040
Capacity factor (%)	90	50.5-68.4	11.1-46.8
Electricity cost (USD)		7.88-8.76E+07	1.03-1.15E+09
O&M cost(% of capital cost)	22.5	22.5	22.5
Decommissioning cost (% of capital cost)	10	10	10
HEEP Results			
% of cost from nuclear power	85	74	5-13
% of cost from hydrogen generation	15	26	95-87
Hydrogen prices (USD/kg)	8.98	11.61-8.92	12.53-4.42

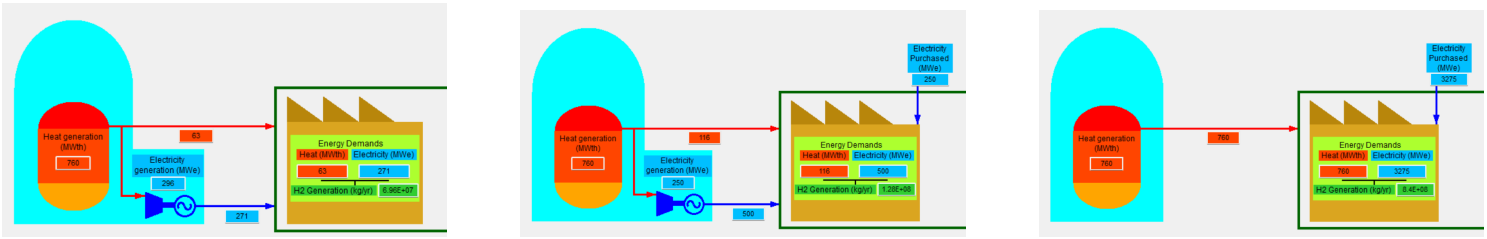

Figure 6: HEEP-generated visualizations for each of the three cases discussed above.

5 Results and discussion

The costs of hydrogen in Table 4 are significantly higher than estimated by the studies in Table 1. This is partly due to the higher cost of THTR-300 compared to the cost projections of most designs. The intermediate scenario in which the nuclear plant provides 50% of electricity is also not ideal, since even though the nuclear plant can help stabilize the overall capacity factor of hydrogen production, all of its electricity-generating infrastructure needs to be built and comprises around 25% of the total capital cost but then is underutilized. The levelized cost of hydrogen becomes significantly cheaper, however, in the "NPP Heat Only" scenario, since the capital cost of the nuclear plant is spread out over a much higher volume of H_2 generated per year. In that scenario, the limiting factor on cost improvement is actually the electrolysis plant.

The main disadvantage of drawing some electricity from wind or solar farms is the lowered capacity factor. Not only does the low reliability of electricity decrease the overall capacity factor of the hydrogen plant, but the intermittent and at times unpredictable nature of wind/solar generation causes the nuclear plant, which conversely has a very high capacity factor and so would be running basically continuously, to waste a significant amount of energy. If the input power from wind/solar had a consistent schedule, the nuclear plant could at least produce electricity for the grid during offline time of the hydrogen plant. However, this would require a periodic mechanical diversion of coolant from the heating cycle to the power cycle loop, which is likely not feasible on demand, as would be needed to satisfy an unpredictable schedule.

Instead, the ideal scenario with the goal of carbon-free hydrogen production is to derive electricity from a reliable and mostly renewable grid. I do not consider this scenario in detail, since in the U.S. such a grid is currently not feasible. But at a LCOE of \$0.036/kWhe (appropriate for solar), a grid reliability of 100%, and without considering transmission line costs,

the LCOH is \$3.05/kg H_2, still not close to being competitive with steam methane reforming. (Comparing the result of this method to the price of green hydrogen is unfair since it assumes a higher capacity factor than has been considered in green hydrogen cost calculations.)

5.1 Opportunities for cost improvement

Is there any possibility for costs to improve in the future? As mentioned in Section 3.2, the estimate of SOEC stack efficiency used in this paper is already high enough to serve as an *upper* bound to efficiency for the forseeable future. One area in which significant improvements are expected which could make a significant difference for price is the tendency of SOEC cells to degrade quickly; O&M costs could decrease in the future with longer stack lifetimes, and in the "NPP Heat Only" case, the O&M cost is by far the largest component of SOEC plant cost, which in turn makes up the majority of the LCOH. [FVOEEAH23]

Where the assumptions of this paper are situated with respect to the future cost of nuclear plants is more uncertain. THTR-300 suffered cost overruns due to unforeseen circumstances. [BKR+90] This is by now commonplace in the nuclear industry in Western countries; in the U.S. since 1970, plants experienced "an average overnight cost overrun of 241%", with most of the increase driven by indirect costs such as planning and decreased productivity owing in part to poor supply chain management, as opposed to direct engineering costs due to the design of the reactor. [EGKK+20] This makes reactor costs difficult to predict from a purely technical/engineering standpoint.

Thus far there is also no industry-wide evidence that costs will decrease as more nuclear reactors are built; this is supported by Figure 7, which shows steadily climbing reactor costs even as we surpass the size of reactors built at which we would have expected to achieve Nth-of-a-kind pricing.

Finally, the regulatory details of coupling a nuclear reactor to a high-temperature electrolysis plant have not been worked out [FVOEEAH23], so encountering regulatory problems in the construction of the first few HTGRs for hydrogen production purposes is not unlikely.

All of these variables introduce considerable uncertainty in the construction cost of a THTR-type reactor today even if exactly the same design was built. Since the operation of THTR-300, research reactors have been built and new HTGR or VHTR designs have been proposed, some with the explicit aim of being used to produce hydrogen. Until reduced costs are demonstrated at commercial scales, however, due to the factors mentioned above, it will remain unclear whether significant cost improvements can be attained.

6 Conclusion

A cost analysis based on financial and technical parameters from THTR-300, which operated at commercial scale for several years, reveals that as a standalone energy source for hydrogen generation, nuclear power is not likely to be competitive with renewable energy sources. Pairing nuclear power as a source of heat with electricity from renewable energy results in lower levelized costs for hydrogen which are comparable to green hydrogen, but while green hydrogen costs are forecasted to decrease significantly in the future, it is unclear whether producing hydrogen with nuclear power will become significantly cheaper.

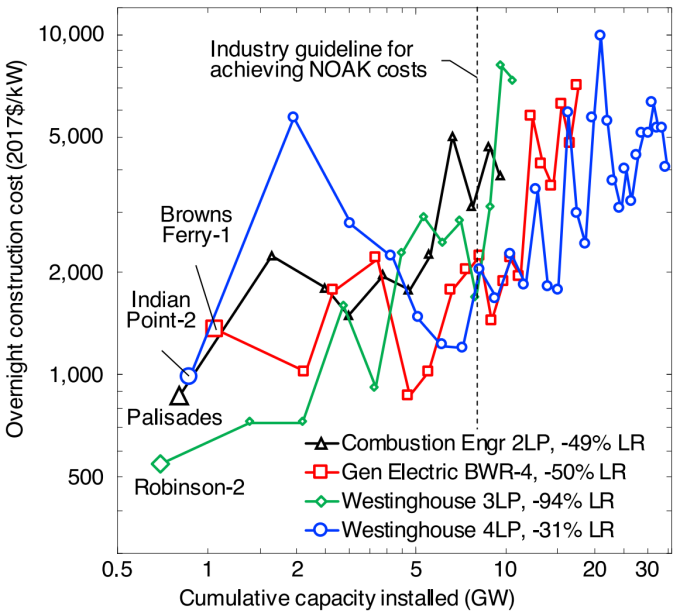

Figure 7: Overnight construction costs for all U.S. plants whose designs eventually exceeded a capacity of 8 MWe, indicated by the dashed line. [EGKK+20]

Appendix A Cost of THTR-300

In this section I explain the process for converting the overall cost of building THTR-300 in mid-20th century Germany to the cost of building the same reactor today in the U.S. The cost figure given for the estimate of total investment into THTR-300's construction in 1982 was 4000 million DM (Deutsche marks) over 164 months (approximately 13.7 years). [BKR+90] I first reconstruct an overnight cost of construction from this figure, the inflation and interest rates in Germany at the time, and the length of time spent on construction; then, this overnight cost estimate is inflated to 2023 Euros and then 2023 USD.

I model the spending curve over the duration of construction as a parabolic curve which intersects the time axis at $t = 0$ and $t = t_f$ and has its peak in the middle, t_f being the length of construction. If at first the effects of interest and inflation are ignored and spending is assumed to be continuous, then the total amount spent (area under the parabola) should equal the overnight cost P_{ON}; at any point in the course of spending, then, the amount already spent is:

$$P(t) = \frac{6P_{ON}}{t_f^3} \int_0^t t'(t_f - t')dt'$$

Now consider the effects of an annual nominal interest rate y and inflation rate x. The total cost in 1984 (at the end of construction) is:

$$P_{tot} = \frac{6P_{ON}}{t_f^3} \int_0^{t_f} t(t_f - t)e^{t \cdot x} e^{(t_f - t) \cdot y} dt$$

while P_{ON} in this formula is given in terms of the cost in 1971, when construction began.

To actually evaluate this integral, I use Germany's yearly interest and inflation rates between 1971-1984 from the IMF. [IMF23] The measure of inflation I use is the GDP deflator, which considers the change in price of all goods and services in the economy. The interest rate I use is the lending rate; this rate only goes back as far as 1977, so to attempt to avoid underestimating the overnight cost, I use the lowest value of the lending rate between 1971-1984 for all years between 1971-1976. Then I evaluate the following sum and solve for P_{ON}:

$$P_{tot} = 4 \times 10^9 DM =$$
$$\frac{6P_{ON}}{t_f^3} \sum_{i=0}^{t_f} (\prod_{j=i}^{t_f} e^{y_j \Delta t_j})(\prod_{k=0}^{i} e^{x_k \Delta t_k})\, t_i(t_f - t_i)\Delta t_i$$

Here $\Delta t_i = \Delta t_j = \Delta t_k = 1$ for all but the final year, during which only 8 months of construction were needed to finish the plant; and $t_f = 13$. The final result for P_{ON} is 1.6 billion DM. This is consistent with the THTR-300 scientists' estimate that about 60% of the final cost of 4 billion DM was "due to price increases because of the longer construction period". [BKR+90]

This is the overnight cost of the reactor in 1971 Deutsche marks. To convert this cost to today's cost in 2023 USD, once again I use the GDP deflator to inflate the price over the years. However, Germany's national currency changed at the start of 1999 from the Deutsche mark, which we have been working in until now, to the Euro. Thus, I inflate the overnight cost of the reactor using Germany's GDP deflator from 1971 to 1999; convert this cost to Euros using the fixed 1999 exchange rate of 1.95583 DM/Euro; inflate this cost in Euros to 2023 using Germany's GDP deflator; and then convert the final cost in Euros to USD.

This results in an overnight cost in 2023 of 3.4 billion USD, which is the figure I use throughout the paper. For perspective, this is \$11,000/kW, a relatively high cost for one of today's reactors (compare to Figure 7), but not unreasonable especially considering the regulatory challenges that THTR-300 faced and which may face a HTGR built today.

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