Reasonable Transition

By John Benson

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1. Reasonable Transition

I try to read from a wide range of sources, in an attempt to better target future papers to my primary readers (members of Energy Central and the therein members of Energy Industry). Since this audience is also part of the general public it is reasonable that, if the general public is confused about a given energy-related issue, this is also a subject I should write about.

One of the (hard-copy) periodicals I receive is Time, as I find this to be an excellent general news source, and it occasionally delves into energy-related subjects.

In my current issue of Time (Jan 31 / Feb 7, pages 9 & 10) there is a one page article that is mainly about the debate in Europe regarding what constitutes a renewable electricity source, and specifically whether natural-gas fired plants should be considered "renewable" under reasonable conditions. Natural Gas is labeled as a "transition fuel", and investments in a natural gas plant will count as "green power" if:

- The plant emits no more than 270 grams of CO_2 equivalent greenhouse gas (GHG) per kWh of electricity produced
- The natural gas plant must replace a plant with higher GHG emissions per kWh

The 270 g / kWh would limit the new plant to extremely efficient combined-cycle power plants. The best number I found was 330 g / kwh, thus additional measures may need to be added, like firing the plant with a mixture of geologically sourced natural gas and either biomethane or hydrogen (see below).

There are also discussions in the EU regarding deeming nuclear electricity generation a renewable, but I will leave that discussion for another day. Personally, I believe nuclear-generated electricity is renewable.

The key point here is this discussion regarding natural gas seems to be an "either or" discussion. In fact, a modern combined cycle plant fueled with geologically sourced natural gas can evolve to very low GHG emissions in the future. I had researched this subject about a year ago and put a few of paragraphs on this subject in a post. Unfortunately I had buried these deeply in a paper that was really on a (somewhat) different subject. I will put these subsections below and add some additional information.

2. Natural Gas to Renewable

This is neither a new concept, nor a really difficult challenge. In fact one can use any gas-fired generator, send biomethane (a.k.a. renewable natural gas or RNG) through the natural gas pipeline network to the plant and it will emit very few net greenhouse gases, today in California (and probably elsewhere), with no plant modifications.

The real challenge is hydrogen. First of all, although it may be theoretically possible to mix a small amount of hydrogen into pipeline natural gas (say 15% to 20%) it's not allowed in these pipelines under current regulations. Second, although most natural gas power plants will probably operate OK on this mixture, when you go to 100% hydrogen, there are major issues. I expect most major manufacturers of natural gas power plants have been working on the issues for some time, and I'm sure one has, my former employer, Siemens Energy. The subsection below will cover this.

2.1. Issues with Hydrogen Fuel in Gas Turbines

Siemens has been working on these designs for many years, and *Siemens fleet experience with high hydrogen content fuels is extensive, with more than 55 units around the world amassing 2.5 million operating hours since the 1960s.*[1]

Using hydrogen in combustion turbines (including those in combined cycle plants) is not a trivial matter: *Hydrogen differs from hydrocarbon fuels by its combustion characteristics, which pose unique challenges for gas turbine combustion systems designed primarily for natural gas fuels. Flame temperatures for hydrogen under adiabatic and stoichiometric conditions are almost 300 ºC higher than for methane. Hydrogen's laminar flame speed is more than three times that of methane and the auto-ignition delay time of hydrogen is more than three time lower than methane, as shown in Figure 5 for flame temperatures of 1600 °C. With these characteristics hydrogen is a highly reactive fuel and controlling the flame to maintain the integrity of the combustion system and reach the desired level of emissions is a formidable challenge for research and development teams.*

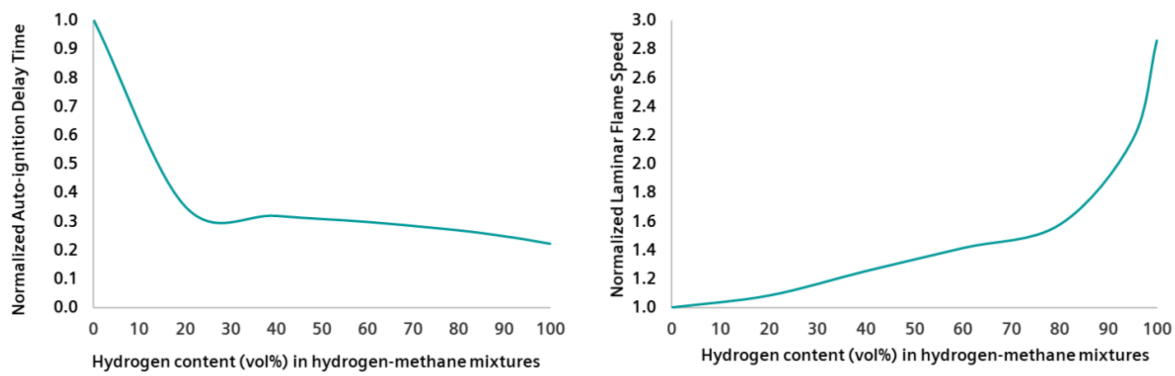

Figure 5: Hydrogen's impact on auto-ignition delay and flame speed for hydrogen-methane mixtures[6]

Gas turbines for recent Siemens utility-scale combined cycle plants use dry low emissions (DLE) combustion systems. Converting these to use partial or 100% hydrogen fuels presents several challenges.

In dry low emissions (DLE) combustion systems*, fuel and air are mixed prior to combustion in order to precisely control flame temperature which, in turn, allows the control of the rates of chemical processes that produce emissions such as nitrogen oxides (NOx). The relative proportions of fuel and air is one of the driving factors for NOx but also for flame stability. Hydrogen's higher reactivity poses specific challenges for the mixing technology in DLE systems:*

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[1] Siemens AG, "Hydrogen power with Siemens gas Turbines". 2020, https://www.siemens-energy.com/global/en/offerings/technical-papers/download-hydrogen-capabilities-gt.html

- *Higher flame speeds with hydrogen increase the risk of the flame burning closer to the injection points, travelling back into mixing passages or burning too close to liner walls leading to damage. This risk increases as the hydrogen content in the fuel is increased and with increasing combustion inlet and flame temperature*

- *Hydrogen's lower auto-ignition delay compared to methane increases the likelihood of igniting the fuel in the mixing passages leading to damage*

- *Changes to thermoacoustic noise patterns because of the different flame heat release distribution can reduce the life of combustion system components.*

Siemens DLE combustion systems generally use swirl stabilized flames combined with lean premixing to achieve low NOx emissions without dilution of the fuel. The acceptable fuel fraction of hydrogen depends on the specific combustion system design and engine operating conditions. Hardware and control system changes are required for higher hydrogen fuel contents to allow the systems to operate safely, meet NOx emissions limits and manage varying fuel compositions. Siemens is in the process of extending the hydrogen capability of its DLE systems.

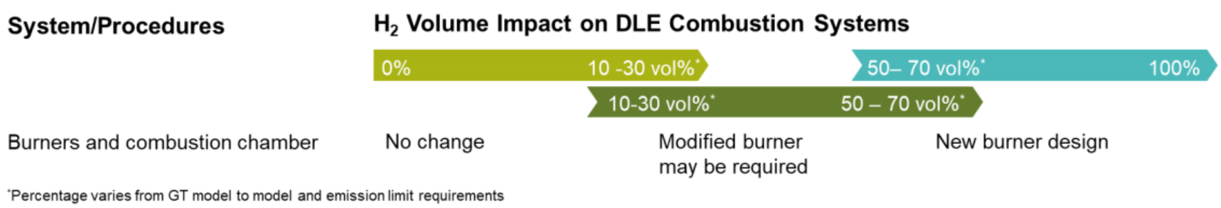

Figure 7: Hydrogen fuel volume impacts on DLE combustion systems

2.2. Evolutionary Path

In the short term many existing combined cycle plants can use partial green hydrogen fuels, thus significantly decreasing their greenhouse gas emissions. In the long term, at least some plants can to evolve to at least 70% green hydrogen operation. Green hydrogen is hydrogen produced by electrolysis using only very low-GHG electricity. This electricity is typically from photovoltaic, wind, hydro or other renewables.

These plants will be composed of.

- Advanced electrolysis systems (including those made by Siemens) powered by low-cost, off-peak renewable power (delivered through the grid) will produce green hydrogen.

- This hydrogen will be stored, probably using large high-pressure cylinders (over 10,000 psi).

- A modified combined cycle plant (including those made by Siemens) will provide the stored power by burning up to 70% hydrogen, and thus will produce reduced greenhouse gases (GHG).

- The residual methane can use biomethane driving the net GHG even lower or possibly negative if CO_2 capture and sequestration are used.

2.3. 100% Hydrogen

Note that this is an evolutionary process, and Siemens has committed to supporting 100% hydrogen operation as described below.

Siemens gas turbines can operate on high percentages of hydrogen fuel, with the specific capability of a unit depending on the gas turbine model and the type of combustion system. See Figure 3 for the "high-hydrogen options" across the portfolio

For new unit applications that are available on specific request. For installed units the capabilities are given in the gas turbine manual. Higher hydrogen mixtures for those existing power plants and options for upgrading are discussed below.[1]

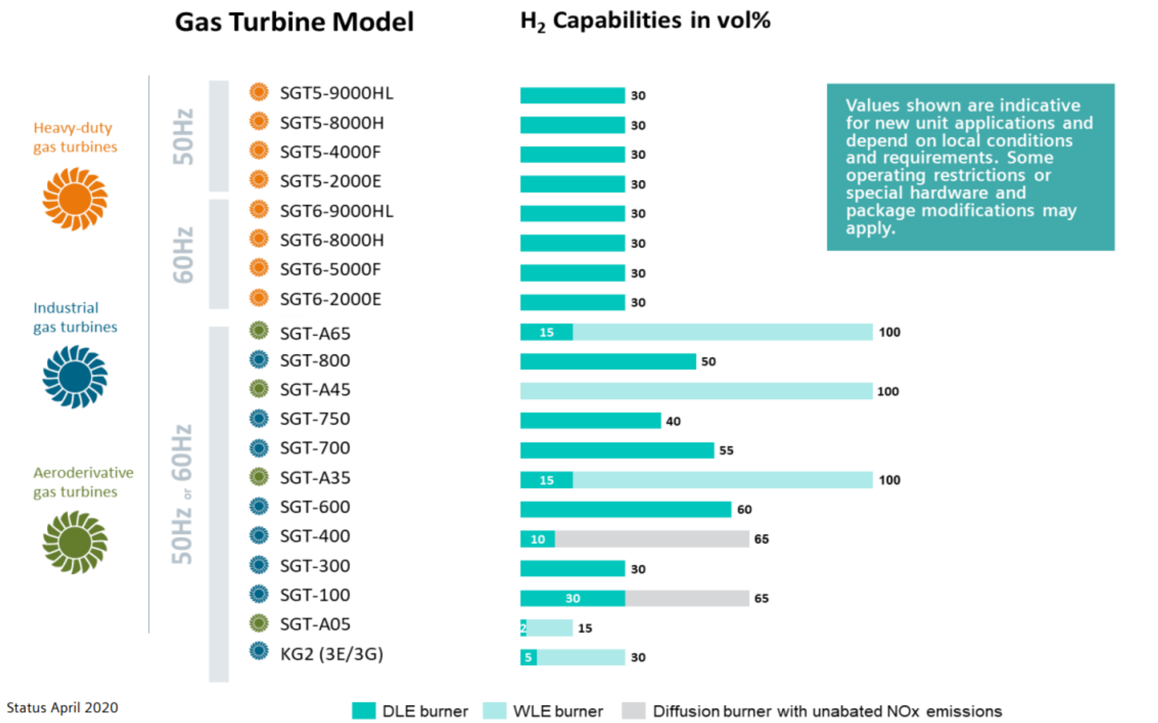

Figure 3: Siemens gas turbine portfolio hydrogen capability (available as "high-hydrogen" options) for new unit applications

Finally, our 100% hydrogen gas turbine program combines extensive technology development for industrial and utility power generation applications. Since the 1960s, Siemens has gained experience with high-hydrogen fuels on non-DLE combustion systems. Beginning in the early 2000s Siemens has invested in the development of DLE hydrogen combustion technology.

By 2030, Siemens intends to have gas turbines with the capability of operating on 100% hydrogen fuel with DLE technology available across our gas turbine portfolio. To achieve this target, we are continuously developing the necessary technologies and implementing these new designs into our product portfolio. Siemens' aeroderivative gas turbines are available to run on 100% hydrogen fuel with WLE combustion systems today. Based on the availability of hydrogen in the different sectors, we will push our hydrogen technology forward to ensure that customer needs are met.

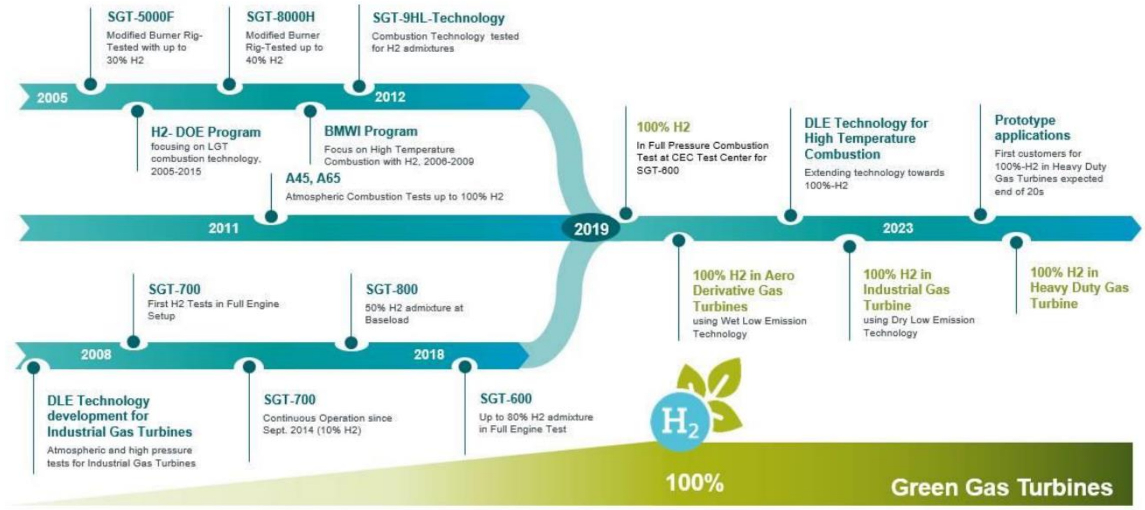

Figure 20: Siemens 100% hydrogen gas turbine roadmap

3. Lodi Energy Center

The Northern California Power Agency's (NCPA) Lodi Energy Center (LEC) is the only large, modern combined cycle power plant that I have experience with. It was ordered in 2009 from Siemens Energy.

In 2012, NCPA opened the Lodi Energy Center (LEC), home to one of the cleanest and most efficient gas-fired power systems in the U.S. It was the first in the nation to take advantage of "fast-start" gas-turbine technology to reduce emissions and provide a rapid response to market and grid conditions. Fast-start technology has the ability to quickly ramp generation up and down, counterbalancing the variable nature of wind and solar energy.[2]

Californians benefit from the addition of the LEC to the state's energy resource mix, as it promotes further investment in renewables, reduces greenhouse gas emissions, and enhances grid reliability. The LEC is a critical part of California's clean and reliable energy future.

The location of the Lodi Energy Center is ideal in terms of leveraging existing infrastructure, and for minimizing environmental impact. The LEC sits on a 44-acre site adjacent to the White Slough Water Pollution Control Facility (WPCF), which treats wastewater from the City of Lodi. The city needed to find a use for its wastewater, and the LEC provided a great solution— the ability to use the City of Lodi's treated wastewater for power plant cooling. This is consistent with a new trend in the public power sector; cities across the country are finding that wastewater treatment and electricity production make good neighbors.

LEC uses a Siemens Flex Plant 30, with a SGT6-5000 Gas (a.k.a. Combustion) Turbine. This design uses a Nooter/Eriksen Heat Recovery Steam Generator (HRSG), and a

[2] Northern California Power Agency, "Lodi Energy Center," http://www.ncpa.com/about/generation/lodi-energy-center/

Siemens Steam Turbine with a SST-700 high pressure section and a SST-900 intermediate / low pressure section.[3]

Although I was multitasking the work on LEC with other tasks, since I was responsible for Siemens protective relays in the region, and had worked with PG&E before, I was responsible for getting formal PG&E approval for all of the protective relays in the plant. PG&E is the transmission-owner for the lines that LEC connected to, and was also the primary utility in the area, so they needed to test and approve the protective relays.

The primary advantage that the Siemens Flex Plant offered over earlier combined cycle plants is its fast-start and fast-ramp capabilities. Specifically, LEC's gas turbine is used for fast response, and its ramp rate is 13.4 MW/min up to 150 MW with no limits on cold, warm or hot start-up. The maximum combined output of LEC is approximately 300 MW. As of the creation of reference 3 the availability of LEC had been 98.5%.

Regarding converting LEC to hydrogen operation, repeating a Siemens statement from above subsection 2.3, "*By 2030, Siemens intends to have gas turbines with the capability of operating on 100% hydrogen fuel with DLE technology available across our gas turbine portfolio."* Based on an earlier chart in that subsection, it appears that the SGT6-5000 is currently capable of combusting 30% hydrogen. I strongly expect upgrading LEC to 100% hydrogen operation will require major equipment replacement.

4. Alternate Paths

Note, from the above text, that there are alternate options to upgrade a modern combined-cycle plant to reduce its net greenhouse gas emissions. These include:

1. Using biomethane, and this can be transmitted to the plant using the existing natural gas network. We covered this briefly above in section 2. Additional information is available in subsections 4.1 & 4.2, below.
2. Mixing a small percentage of green hydrogen into the geologically derived natural gas to fire the plant
3. Mixing a higher percentage of green hydrogen into the geologically derived natural gas to fire the plant, which may require some modifications to the plant
4. Using 100% green hydrogen to fire the plant which may require substantial modifications to the plant, and will only be possible at some point in the future

Option 1 is available today, but is supply-constrained, and this channel will need to be developed as demand ramps-up. Side benefits are (a) that this can evolve to negative emissions technology (NET)[4] and (b) biomethane can be used in options 2 and 3 above in lieu of "…geologically derived natural gas…" with no other modifications.

Option 2 is available today, but a given plant would need to add electrolysis green hydrogen production systems and storage.

Option 3 may be available in a few years, but a given plant would need to add electrolysis green hydrogen production systems, storage, plus the required changes.

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[3] Rafael Santana, Siemens, Presentation on the Siemens Flex Plant 30 for the Northern California Power Agency, 2013, http://ccug.users-groups.com/AnnualMeetings/2013/Presentations/Siemens%20Flex-Plant%2030.Presentation-Santana.pdf

[4] For additional information on NET, see "Climate Change - When Time Runs Out," section 5, https://www.energycentral.com/c/ec/climate-change-when-time-runs-out

Option 4 may be available around 2030, but a given plant would need to add electrolysis green hydrogen production systems, storage, plus the required major modifications.

4.1. California Ramping Biomethane

Additional "late breaking news" regarding the above Option 1. The California PUC has started setting biomethane targets for utilities:

The California Public Utilities Commission (CPUC), in ongoing efforts to support clean energy, today set biomethane procurement targets for utilities to reduce short-lived climate pollutant (SLCP) emissions.[5]

The decision establishes a biomethane procurement program that is carefully crafted to help achieve the state's SLCP goals, which call for a 40 percent reduction in methane and other SLCPs by 2030. Renewable gas procurement will reduce otherwise uncontrolled methane and black carbon emissions in our waste, landfill, agricultural and forest management sectors. These sectors are responsible for more than 75 percent of the state's methane emissions, according to California Air Resources Board 2019 data. Reducing SLCPs, which are a far more potent greenhouse gas than carbon dioxide, is one of the most effective ways to slow the pace of climate change.

Senate Bill 1440 (Hueso, 2018) authorizes the CPUC to adopt biomethane procurement targets or goals for the gas utilities it regulates, and Senate Bill 1383 (Lara, 2014) requires California to reduce emissions of methane by 40 percent below 2013 levels by 2030. The biomethane will displace some of the fossil fuel natural gas that utilities supply to their customers.

The decision establishes short-term and medium-term procurement goals, including:

The short-term 2025 biomethane procurement target is 17.6 billion cubic feet of biomethane, which corresponds to 8 million tons of organic waste diverted annually from landfills. Each utility will be responsible for procuring a percentage of the total in accordance with its proportionate share of natural gas deliveries.

The medium-term 2030 target for biomethane procurement is 72.8 billion cubic feet per year. This higher amount will help the state achieve its goal to reduce methane emissions 40 percent by 2030. It reflects approximately 12 percent of current residential and small business (known as "core gas customers") gas usage in 2020.

Because biomethane from dairies is currently incentivized in other state programs, under the decision it may be procured to satisfy only the medium-term target, after the utility has procured sufficient biomethane from organic waste diverted from landfills to divert its share of 8 million tons of organic waste. For the medium-term goal, there is a ceiling on dairy biomethane of 4 percent of total biomethane procurement. Measures are required to avoid adverse environmental impacts to air and water quality from any dairies that provide biomethane.

"Tackling methane and other short-lived climate pollutants is critical given our climate crisis," said Commissioner Clifford Rechtschaffen, who is assigned to the proceeding. "This decision will reduce emissions from some of the state's leading methane sources."

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[5] California Public Utilities Commission (CPUC), "CPUC Sets Biomethane Targets for Utilities," Feb 24, 2022, https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-sets-biomethane-targets-for-utilities

“It is formidable to decarbonize because carbon has been the input and output of so much of our economy for so long,” said President Alice Busching Reynolds. “This reality comes into even more focus as we move beyond the easier first steps into the more complex ones. This decision considers a variety of different interests and viewpoints and strikes a good balance to advance the critical goal of decarbonization.”

Author’s Comment: The primary reason for the above CPUC (etc.) action is the reduction of SLCP emissions. However by capturing these emissions from biomass (or more likely, harvesting the biomass and producing biomethane from this in an industrial process) and burning the biomethane in a power-plant, we convert the biomethane to carbon dioxide (CO_2). In the short-term CO_2 is a much weaker greenhouse gas than methane. Better-yet, if the CO_2 from the combustion at the power plant is captured and geologically sequestered, the SLCP emissions largely go away.

4.2. Biomethane Production

For more thorough coverage of biomethane see Section 3 of Tech Race:
https://energycentral.com/c/cp/tech-race