IICEC

SABANCI UNIVERSITY
ISTANBUL INTERNATIONAL
CENTER FOR ENERGY AND CLIMATE

Sabancı Üniversitesi 20 yıl

IICEC ENERGY AND CLIMATE RESEARCH PAPER

USING NATURAL GAS AS AN ENVIRONMENTALLY SUSTAINABLE POWER SOURCE WITH SOLID OXIDE FUEL CELLS

January 2020

Carmine Difiglio, Danial Esmaeili, Serhat Yesilyurt

Sabancı University

Table of Contents

Using Natural Gas as an Environmentally Sustainable Power Source with Solid Oxide Fuel Cells[1]

1. Summary

Research, pilot projects and government policies to commercialize carbon capture in the power sector have focused on coal plants. However, the expected world-wide consumption of natural gas in the power sector is not consistent with a sustainable environmental future without also employ-ing carbon capture technologies to natural gas plants. One reason carbon capture from natural gas has not received much attention is, as will be discussed below, the very high cost of carbon capture from natural gas plants compared to the already considerable cost of carbon capture from coal plants. Capture of carbon with conventional natural gas turbines is not currently economically practical. A different natural gas to electricity technology may be needed if carbon capture with turbines (for example, see Zhu, et. al.[i] on the use of chemical looping) proves not to be cost-effective. This different alternative electric-generating technology should not have a higher LCOE than natural gas turbines and it must permit carbon capture at low cost. Ideally, the cost of carbon capture should be significantly lower than from coal plants as measured by the cost per ton of cap-tured CO_2.

Solid oxide fuel cells (SOFCs) are one of the leading technologies to meet these requirements, SOFC emissions of CO_2 without carbon capture are relatively low due to their high efficiency. Significantly, in the SOFC exhaust, CO_2 is only comingled with water and unreacted CH_4. This enables low-cost separation of CO_2. In addition, the efficiency losses from the application of car-bon capture are minimal compared to the significant efficiency losses when carbon capture is ap-plied to coal power plants or natural gas turbines.

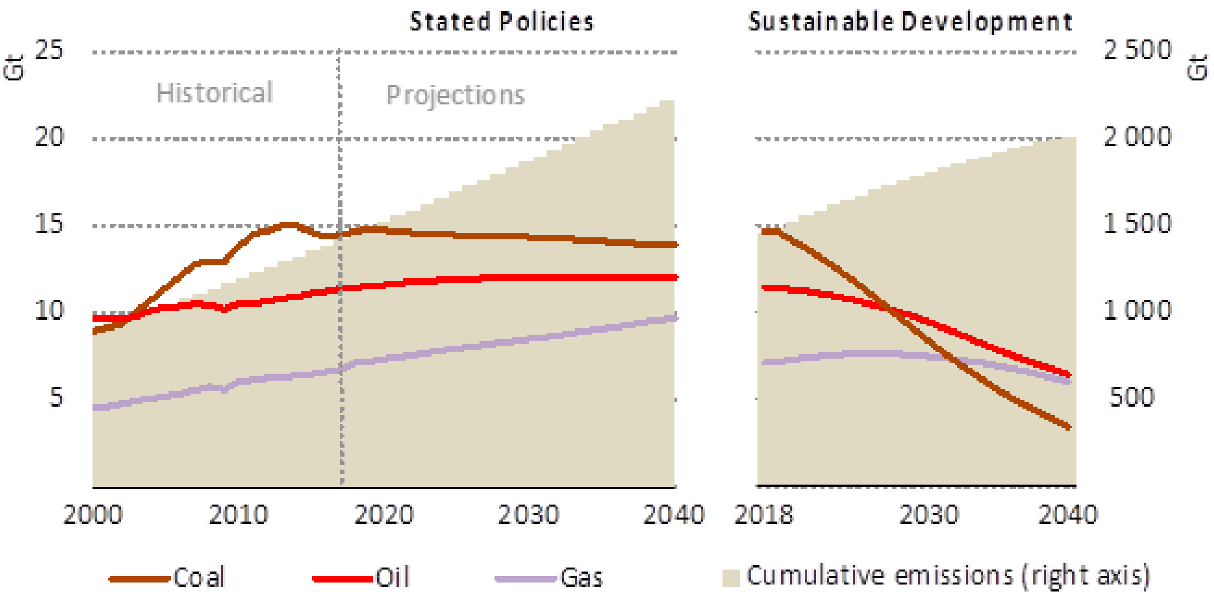
The primary barrier to the uptake of SOFCs is the development of a grid-scale SOFC with a com-parable cost and reliability compared to the natural gas turbine. With a cost-competitive grid scale SOFC technology, the additional cost of carbon capture would be minimal compared to the cost-prohibitive carbon capture technologies that are available for coal power plants and natural gas turbines. Consequently, commercialization of carbon capture could be achieved a lower cost with a lower burden on the economy than is now the case. While the current research to achieve cost-competitive and reliable SOFCs for grid-scale application is encouraging, these efforts should be significantly increased in order to achieve more rapid technology development and the opportunity to achieve grid-scale commercial application, a necessary step that enables further cost reduction.

2. Introduction

There is a critical need to provide electric services for a growing worldwide population that is ex-periencing rapid economic development in some of the most populous countries. At the same time, these services must be provided with dramatically lower greenhouse gas (GHG) emissions. Multiple studies have shown that the power-sector would have to achieve deep cuts in GHG emis-sions in order to make significant cuts in overall GHG emissions. This is because a large share of energy-sector GHG emissions come from the power sector and reducing GHG emissions in the power sector is relatively cost effective compared to reducing emissions in other sectors (especially the transportation sector).[ii] Consequently, it is important to increase efforts to use electricity efficiently and provide electricity from near-zero greenhouse gas sources. However, fossil fuels such as coal, oil and natural gas have been widely used to generate electricity over the last two hundred years and, along with the use of fossil fuels in other sectors of the economy, is responsible for higher GHG concentrations in the atmosphere and a consequent global warming trend. Not-withstanding political measures, consumer trends, market dynamics and societal awareness to ad-dress the climate-change problem, all current programs and plans to reduce energy-sector GHG emissions are expected to fall short of achieving the net-zero emission goals that are necessary to avoid dangerously high concentrations of atmospheric greenhouse gases.[iii] It is difficult for gov-ernments to take dramatic actions to limit GHG emissions if those actions limit or significantly increase the cost of energy, especially in the developing world. In order to commercialize low-GHG technologies, such as renewable energy and using fossil fuels with carbon capture and stor-age, these technologies must be capable of providing energy services at a reasonable cost and, preferably, providing energy services at the lowest cost. The challenge is formidable as shown in Figure 1.

[1] This paper updates and replaces an *IICEC Energy and Climate Research Paper* of the same name that was published May 2018.

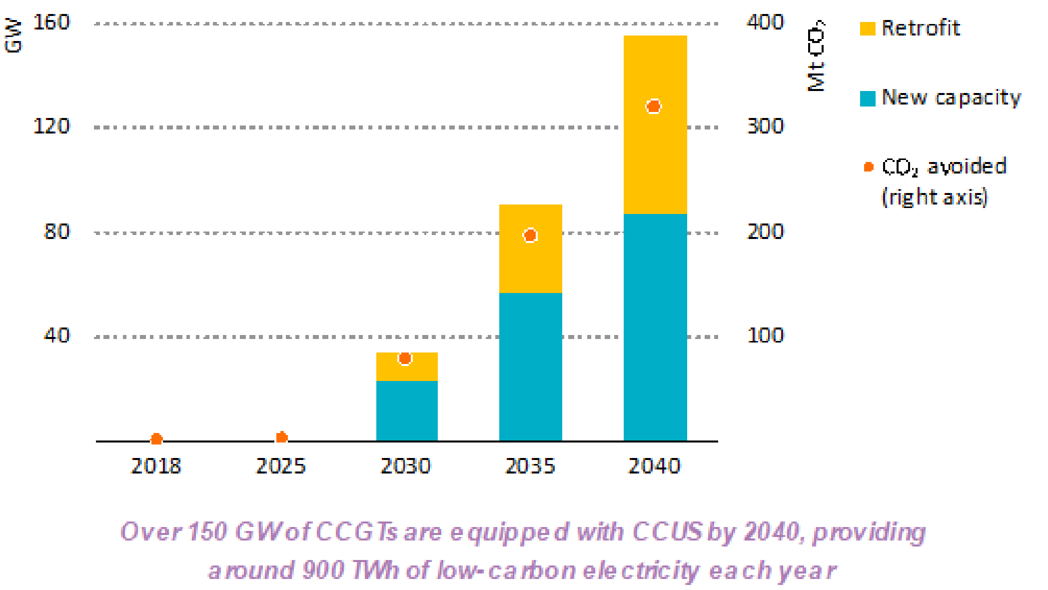
Figure 1: International Energy Agency CO_2 Emission Scenarios [iv]



Based on analysis recently completed for the International Energy Agency's *2019 World Energy Outlook,*[v] while some countries have adopted "net-zero" emissions policies, too few countries in-clude them for the IEA's "stated policies" scenario, and this scenario would fall far short of an emissions reduction pathway that is needed to achieve net zero emissions by 2070. As shown in Figure 1, in the "stated policies" scenario, the IEA expects very little reduction in coal and oil emissions out to 2040, and an increase in natural gas emissions. This does not mean that techno-logical progress and climate policies are not working at all: When you add the growing demand for energy services over time, current policies are only keeping energy emissions relatively stable in-stead of significantly decreasing them. The IEA's "sustainable development" scenario, which would achieve 2070 net-zero emissions, requires deep reductions of coal and oil emissions by 2040 and a gradual reduction of natural gas emissions after 2025.

Achieving power sector emission goals is a critical need for overall emission reductions. It is not realistic to achieve the necessary emission reductions by relying on one technology such as renew-able energy. While renewable energy is growing rapidly to help meet this challenge (from 2000 to 2018, more GW capacity of renewable power was added than all other sources combined[vi]), how-ever, there are limits to what renewable energy can accomplish by itself.[vii] Other low-GHG emis-sion technologies will be needed. Nuclear power has long held promise to provide competitive baseload power with very low GHG emissions. However, besides public opposition to nuclear power in many countries, recent experience has shown that high cost and huge financial risks make it much less likely that new nuclear reactors will be built in competitive power markets without government support.[viii] Government support is available in several countries in Eastern Europe, the Middle East and Asia where nuclear power investments are proceeding. Nonetheless, net nuclear capacity additions (63 GW to a 2040 total of 482 GW) are expected to lag far behind net re-newables additions (4,716 GW to a 2040 total of 7,233 GW), net natural gas additions (906 GW to a 2040 total of 2,651 GW) and net coal additions (92 GW to a 2040 total of 2,171 GW).[ix] Contin-ued capacity additions for natural gas and coal power plants reflect the ample world-wide supplies of natural gas and coal. The more rapid growth of natural gas in the power sector, compared to coal, can also be explained by its environmental benefits. Nevertheless, the IEA's expected natural gas plant fleet will not be compatible with a sustainable emissions trajectory without the application of carbon capture. Even though natural gas power plants have about half of the CO_2 emissions per kWh than coal, by 2030, the worldwide generating capacity of natural gas plants will exceed any type other than renewables. There is "no room" for un-sequestered emissions from natural gas power plants even though they also play a critical role to reduce emissions by replacing coal-fired power plants. Consequently, capturing CO_2 from natural gas plants is a necessary component of a sustainable energy strategy. The IEA recognizes this, as shown in Figure 2.

Figure 2: CCUS Required in Natural Gas Power Generation to meet the Sustainable Development Emission Scenario[x]



The IEA "sustainable development" scenario requires, by 2030, significant new natural gas capaci-ty with carbon capture as well as retrofit of existing natural gas plants. While the IEA scenario anticipates carbon capture using CCGT technology, this paper explores an alternative approach. Innovative thinking and alternative approaches are likely to be important as industry adjusts to the imperative to greatly reduce its carbon footprint. The power sector is the leading edge of change since power sector emission reductions are essential to meet overall emission goals. Technologies for the power sector can be viewed more generally as generators of clean energy carriers to reduce emissions throughout the economy. For example, clean electricity will reduce transport sector emissions via plug-in electric vehicles and also substitute for a variety of energy needs in industry and households. The same power-sector technologies that produce clean electricity can also be used to produce clean hydrogen, the other leading candidate for an economy-wide clean energy carrier. Hydrogen will likely be necessary to replace petroleum in a wider range of transportation services than electric vehicles are likely to achieve. There is also a need for high-temperature heat in industry that cannot be satisfied with electric power (for an overview of the role of hydrogen in an energy transition, see Gençer 2019[xi]).

3. Overview of Carbon Capture and Storage

Carbon Capture and Storage (CCS) removes CO_2 from a fossil-fuel-using energy source (such as a coal- or natural gas-powered power plant) and transports it via pipeline to be pumped deep enough into the earth to secure safe, long-term storage.[2] Storage reservoirs include deep saline formations, depleted oil and gas wells, and unminable coal beds. These reservoirs have cap-rock that would prevent CO_2 from migrating to the surface.

CCS could be one of the most important methods to reduce of CO_2 emissions. Depending on the world's continued reliance on fossil fuels, CCS has the potential to be of comparable importance to energy efficiency, renewable energy or nuclear power. However, CCS is a relatively undeveloped technology, at least for the purpose of reducing CO_2 emissions,

[2] Carbon capture utilization and storage (CCUS) also includes the use of CO_2 captured from power plants for enhanced oil recovery or other industrial or commercial uses. While an important stepping stone for CO_2 capture, since CO_2 would have a value stream if used, the volume of CO_2 that must be removed to achieve sustainable use of fossil fuels far exceeds the industrial or commercial needs for CO2. Consequently, the above discussion focuses on CO_2 storage but we use the acronym "CCS" to also include utilization projects.

as CO_2 injection is typically used for tertiary oil recovery.[3] The earliest application of CCS for the purpose of avoiding CO_2 emissions was the Weyburn-Midale Carbon Dioxide Project (2002). The CO_2 injected into the Weyburn-Midale fields was derived from a coal-gasification power plant. While the Weyburn-Midale and some other CCS demonstration projects have provided valuable data on the cost and feasibility of CCS, CCS has failed to emerge as a commercial-scale method to reduce of CO_2 emissions.

4. Carbon Capture from Coal

The primary barrier to the uptake of CCS has been the high cost of CO_2 separation during the pro-cess of burning fossil fuels to produce electric power. Various methods have been developed but can be classified into three types: 1) pre-combustion, 2) oxy-combustion; and 3) post-combustion. The technology used in the pre-combustion approach uses coal-gasification and water shift reaction to produce CO_2 and H_2 (see the adjacent box for more detail). The H_2 is provided to a turbine and the CO_2 is compressed for transport and storage. In essence, a chemical plant and hydrogen-fired turbine *replaces* the conventional coal power plant where coal is burnt to produce steam for steam turbines. The cost per kWh of a pre-combustion CCS plant would be at least 32% higher than a standard coal plant that meets strict environmental requirements.[xii]

Oxy-combustion can be employed to produce a flue gas that is almost entirely CO_2 which then can be compressed and stored. By combusting coal with oxygen, one avoids having to separate CO_2 from the flue gas that contains a considerable volume of air as well as NO_x. The main problem with this approach is the expense (45% more expensive per kWh) and the high energy consumption of separating CO_2 from air.

Coal is partially oxidized in a gasifier producing CO and H_2 (syngas).

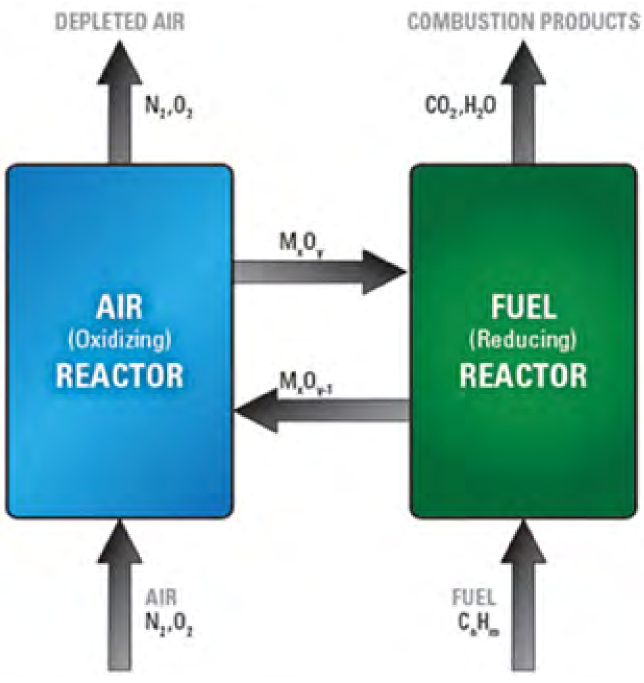
$$3C + O_2 + H2O \rightarrow H_2 + 3CO$$

For precombustion CCS, more hydro-gen is gained with a water shift reac-tion and, more significantly, the CO reacts to become CO_2.

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

The H_2 is sent to a turbine to produce electricity while the CO_2 is compressed to transport via pipeline for sequestra-ton.

Figure 3: Chemical Looping[xiii]



[3] However, in almost all cases, the use of CO2 for tertiary oil recovery does not employ CO2 that was derived from man-made sources. Consequently, the CO2 is merely moved from one underground reservoir to another.

A promising alternative to air separation is chemical looping in which a metal oxide is used to provide oxygen to a fluidized bed for coal combustion. The oxygen-depleted metal oxide is "looped back" to recapture oxygen and again return oxygen to the fluidized bed. Figure 3 (above) illustrates this process. The "fuel reac-tor" is the fluidized bed of the steam coal plant receiving its oxygen from the "air reactor" in the form of a metal oxide, absent any N_2. The oxygen-depleted metal oxide returns to the air reactor where oxygen is recovered and it circulates again to the fuel reactor to provide more oxygen for coal combustion. This process avoids the high energy consumption of air separation and could offer a relatively cost-effective approach to achieve carbon capture from coal. However, while promising research is being conducted on this method, there is, as yet, no commercial application of the technology.

Post-combustion capture of CO_2 typically uses techniques such as carbon scrubbing or membrane gas separation. Since the percentage of CO_2 and pressure in the flue gas is relatively low, post-combustion capture cannot be expected to remove as high a percentage of CO_2 as pre-combustion or oxy-fuel technologies. Post-combustion capture is estimated to increase the cost of power from coal power plants by 32% to 70%.[xiv,xv] As with pre-combustion removal of CO_2, commercially available carbon capture technologies would raise the cost of coal power plants to un-economic levels as well as making them less efficient.

The estimated costs of CO_2 capture from coal are presented in Table 2 (on pg.8). They range from $35 to $45 per ton of CO_2. These costs are not outside the bounds of future carbon-costing re-gimes. Nonetheless, they do not fully reflect the costly and difficult pathway needed to achieve commercial scale CCS from coal. The time required to transform subsidized pilot projects to scal-able and economically viable plants, at these carbon prices, is likely to take decades. The IEA *Energy Technology Perspectives* reports provide "pathways" to CCS commercialization but actual progress versus estimated requirements regularly fall short. According to Nykvist, international funding for carbon capture from coal would have to increase by a factor of 10 in order to achieve the IEA CCS scenarios.[xvi]

5. The Natural Gas Revolution

In years past, there has been little discussion of using carbon capture and storage for natural gas plants. There were two main reasons for this. First, coal seemed to be a more natural target since a coal plant has twice the carbon emissions per kWh of electricity produced than a natural gas plant.[xvii] Second, natural gas was not perceived to be a fuel that would be available in abundant quantities, at competitive prices, far enough into the future to expect the long-term use of natural gas in the power sector. Capital investments in natural gas plants are recovered quickly insulating investors from the risks of longer term increases in the price of natural gas. Natural gas supplies were dominated by Russia and the Middle East and there were not any expectations that a trans-parent global market for natural gas would ever evolve.

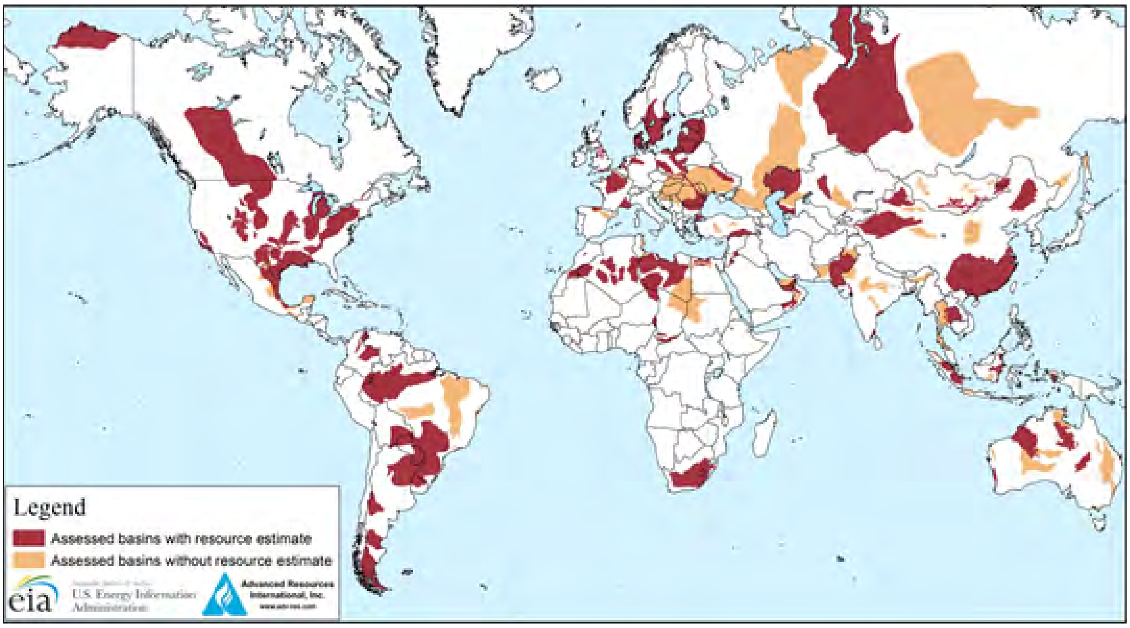
The picture today is very different. Vast reserves of tight gas have now become economically re-coverable. Using the technologies of horizontal drilling and hydraulic fracturing, many tight gas formations can yield large quantities of natural gas at low cost. Consequently, as shown in Table 1 (below), economically recoverable natural gas reserves are now estimated to be large enough to fuel the world's power sector for many decades. In addition, as shown in Figure 4, the currently estimated unproven economically recoverable shale gas reserves of over 337 trillion cubic meters are more evenly distributed among world regions than conventional natural gas reserves.

Table 1: Economically Recoverable Natural Gas Reserves by Region[xviii]

Region	Conventional	Unconventional
Eastern Europe & Eurasia	160	43
Middle East	132	12
Asia Pacific	44	93
OECD Americas	81	82
Latin America (non-OECD)	27	48
Africa	35	22
OECD Europe	35	22
World Total	519	337

Figure 4[xix] also highlights the fact that unconventional gas reserves are often located near popula-tion centers, making the transport of produced natural gas more economic.

Figure 4: World-Wide Distribution of Unconventional Natural Gas Reserves



The impact on new economically recoverable reserves of natural gas is also evident in the recent projections of natural gas production. By 2040, the IEA projects that annual natural gas production from unconventional resources will increase by 1,061 billion cubic meters while increasing by only 622 billion cubic meters from conventional sources. Overall natural gas production is expected to increase from 3,536 billion cubic meters to 5,219 billion cubic meters.[xx]

With public policies and considering the cost of CCS technologies for coal plants, coal is expected to be in significant decline in order to meet the emission targets necessary to limit greenhouse gas concentrations to 450 parts per million. The IEA expects, in the "2 Degree Scenario," that the pro-duction of electricity from coal will only be one-quarter as much in 2040 than it was in 2014.[xxi] While natural gas plants have relatively low carbon emissions compared to coal, they are still too high to be compatible with the 2 Degree scenario. Keeping natural gas fired power plants in a 2 Degree future will require CO_2 capture and storage.

6. Carbon Capture from Natural Gas

In emission reduction regimes driven by the "cost of carbon" approach, the use of carbon capture from natural gas is more challenging then it would be for coal. In these carbon markets, the most cost-effective carbon reduction technologies are employed before others. Consequently, if there was a price on carbon, the priority would be to use carbon capture for coal plants well before it would be used for natural gas plants. For example, the technologies for post combustion separation of CO_2 from coal and natural gas are similar except that the cost per ton of CO_2 removed from nat-ural gas would be much higher because the concentration of CO_2 in the flue gas is much lower.

The worst approach for removal of CO_2 from natural gas, relative to the equivalent methods that could be applied to coal, is pre-combustion separation. Unlike the integrated gasification combined cycle (IGCC) approach used for coal, the steam reforming and water shift units do not *replace* anything. For coal, with the addition of the coal gasification unit and hydrogen-powered turbines, this hardware *replaces* the steam coal plant. For natural gas, the hardware to convert CH_4 to CO_2 and H_2 is an *additional* cost since the plant still requires combustion turbines to produce electricity (in addition, the turbines are likely to be more expensive since the natural gas turbines must be re-placed by turbines that can tolerate a much higher percentage of hydrogen with consequently high-er combustion temperatures). Oxy-fuel combustion is also much more expensive for a natural gas plant as cryogenic distillation technology that could be employed and would also require a rede-signed natural gas turbine.[xxii]

The estimated costs of CO_2 separation in coal and natural gas plants are summarized in Table 2.

Table 1: Cost Comparison of CO2 Separation: Coal vs. Natural Gas [xxiii] (2018USD)

Type of Power Plant	Pre-Combustion	Oxy-Fuel	Post-Combustion
Pulverized Coal	\$29/ton CO_2	\$45/ton CO_2	\$42/ton CO_2
Natural Gas Combined Cycle	\$139/ton CO_2	\$126/ton CO_2	\$72/ton CO_2

Note: Costs include CO2 compression to 110 bar, excluding storage and transportation costs.

As discussed above, using pre-combustion for natural gas is quite expensive, \$139/ton of CO_2, because there is no offsetting savings achieved by *replacing* the pulverized coal plant with an IGCC plant. Pre-combustion capture simply *adds* chemical processing while still relying on com-bustion turbines to produce electricity. Oxy-fuel combustion is estimated to be slightly less expen-sive per ton of CO_2 than precombustion removal but this cost does not include the likely higher cost of the redesigned natural gas turbine. The costs of CO_2 separation from the flue gas are esti-mated to be about twice as high for a natural gas plant compared to a coal plant, reflecting the low-er amount of CO_2 saved per kWh of electricity produced.

If natural gas is to remain a viable long-term power-sector fuel in a "2-Degree" world, there will have to be a more cost-effective way to capture CO_2 from a natural gas plant than the technologies reviewed above. Ideally, this gas-to-electricity generation technology should be competitive with natural gas turbines and also capture CO_2 emissions with minimal additional cost. In addition, the technology, unlike the current CCS concepts that could be used for coal or natural gas, should not require complex pilot projects that would take several years or decades before becoming commer-cially scalable power plants. A promising technology that may be able to meet these requirements is the solid-oxide fuel cell (SOFC) and it is the *raison d'etre* for this paper.

7. Current Deployment of Solid Oxide Fuel Cells in the Power Sector

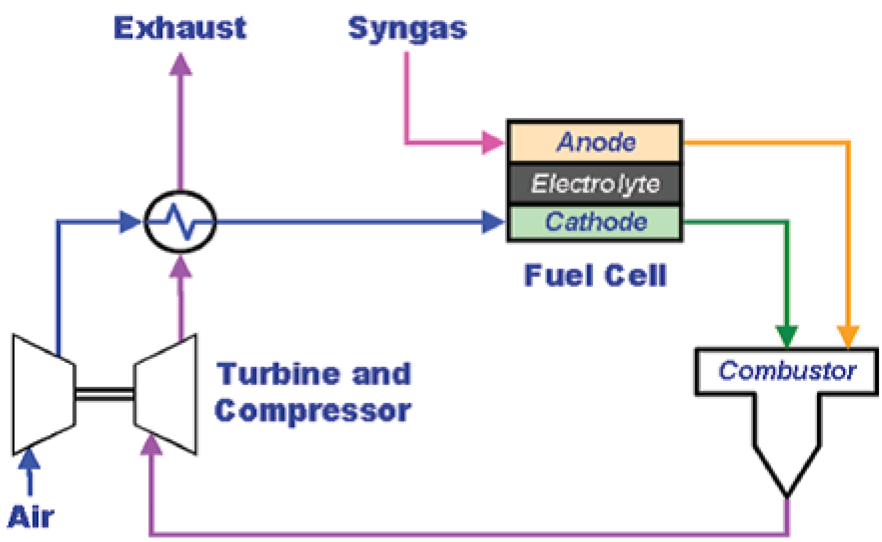
SOFCs are a commercially produced product for niche markets. For example, Bloom Energy mar-kets power from their SOFCs (up to 250 kW capacity) to power the headquarters of several large California companies (a U.S. State with relatively high electricity prices).[xxiv] In Germany, Bosch Thermotechnology markets its SOFCs to provide decentralised power and heat services in residen-tial applications. Bosch emphasizes its high efficiency compared to other decentralised power and heat generators claiming a 50% reduction of CO_2 emissions "compared to conventional power and heat generation." [xxv] Other companies offering SOFCs for residential and other distributed power applications are Convion (Finland), [xxvi] Elcogen (Finland/Estonia),[xxvii] and CERES Power (UK), although there are several others supplying this market.

Larger SOFCs are marketed by Mitsubishi and other companies. Mitsubishi offers a 1,000kW hybrid unit (described below) for industrial applications.[xxviii] As discussed below, the efficiency of an advanced hybrid system could potentially increase to over 70%. An important factor behind the recent commercial interest in marketing SOFCs is the significant potential that exists for cost re-duction using thin ceramic electrolytes and lower operating temperatures, as well as other design features to increase efficiency (some of the products mentioned above incorporate these technolo-gies).[xxix] While SOFCs cannot now compete with natural gas turbines as a reliable cost-effective grid scale technology for utilities or independent power producers, there is a significant likelihood that government and academic research, along with commercial development, will produce a com-petitive grid-scale SOFC industry.

8. Solid Oxide Fuel Cells Explained

Owing to their high operating temperature, high efficiency and fuel flexibility,[xxx] SOFCs are the most suitable candidate for hybridization with combustion based thermal power systems. The most typical configuration is the integration of the SOFC with a gas turbine.[xxxi] Figure 5 shows a dia-gram of a typical SOFC – gas turbine hybrid system.

Figure 5: SOFC-Gas Turbine Hybrid System[xxxii]



Typical cycle includes a compressor, a gas turbine, a combustor and the SOFC. Without the fuel cell, the heat engine is a Brayton cycle, where the high pressure compressed air enters into a com-bustor where the energy from the fossil fuel increases its energy, which is converted into useful work in the turbine. While a part of the work from the turbine is used in the compressor, the rest is converted into electricity. The fuel cell is placed before the combustor and converts the part of the energy in the syngas (which is the mixture of partially reformed hydro-carbon, such as natural gas, hydrogen and carbon monoxide) into electricity directly with high efficiency 60% or more. The exhaust of the fuel cell is rich with fuel and unburned hydrogen, carbon-dioxide and water vapor. The remaining fuel in the exhaust can be burned directly with oxygen (much less than the total oxygen required to burn the hydro-carbon, as most of it, about 80%, has already been converted into CO_2 and H_2O) to produce more carbon-dioxide and water vapor. The exhaust that exits the turbine is the mixture of CO_2 and H_2O, which can be condensed and CO_2 can be removed. Alternatively, CO_2 can be removed from the fuel cell exhaust and the combustion of the remaining fuel with air, and in this way, it still achieves (not perfect but) a very high CO_2 capture as well in the overall.

Typical SOFC arrangement consists of ceramic-based porous anode and cathode electrodes and a solid electrolyte as shown in Figure 6. When hydrocarbons are used as fuel, reforming reaction of hydrocarbons with water vapor produces carbon monoxide and hydrogen in the anode. For exam-ple, methane reforms to hydrogen and carbon-monoxide:

$$CH_4 + H_2O \rightarrow 3H_2 + CO$$

Electrochemical reaction of hydrogen with oxygen ions coming from the cathode is the main reac-tion in the anode as water being the only product in addition to electrons that make up the current that flows in the circuit:

$$H2 + O^{2-} \rightarrow H_2O + 2e-$$

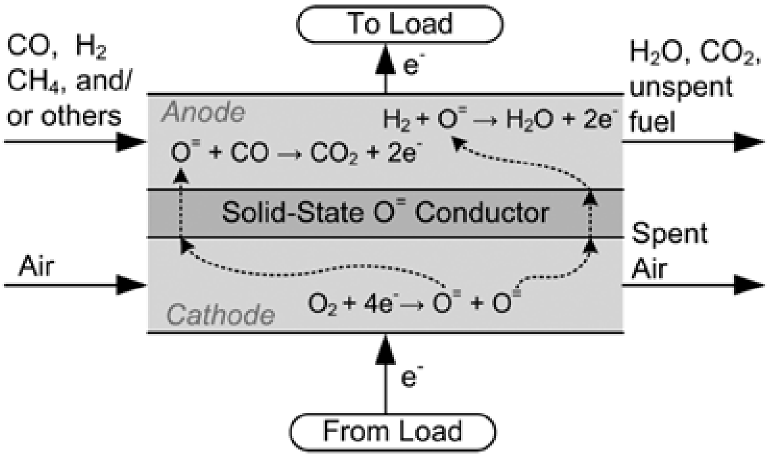
Carbon monoxide from the main reforming reaction can react with oxygen ions to form carbon dioxide directly, or in the presence of sufficient water vapor, water-gas-shift reaction generates hydrogen and carbon dioxide as well:

$$CO + O^{2-} \rightarrow CO_2 + 2e-$$

$$CO + H_2O \leftrightarrow H_2 + CO_2$$

Overall, fuel enters to the anode and water vapor and carbon dioxide exit as products along with unspent fuel if fuel-rich operation is preferred. In fact, extra fuel in the anode side is always desir-able to ensure uniform current and reactions throughout the cell as starvation of fuel is often asso-ciated with undesirable degradation issues. The cathode operates with air, as atmospheric air enters and oxygen-depleted air exits.

Figure 6: Layout of SOFC Operation[xxxiii]



The main role of the electrolyte is to keep the reactant gases in the anode and the cathode separate and allow only oxygen ions to transfer from the cathode to the anode. Whereas porous electrodes ensure diffusion of gas species to reaction sites and conduct electrons. SOFC electrolyte is made of a solid material, such as yttria-stabilized zirconia (YSZ), which is a good ionic conductor at high temperatures (600 – 1000 oC) but acts as a barrier for gaseous reactants.[xxxiv] In addition to YSZ, a number of ionic conductors have been studied to attain improved ionic conductivity at lower tem-peratures, such as gadolinia or samaria-based ceria (GDC or SDC). YSZ is also used in the anode electrode as a part of the porous ceramic-metallic (cermet) composite, which contains nickel as a common metal because of its favorable electric properties and as a catalyst that promotes the oxi-dation of the fuel and the reforming reaction. SOFC cathodes are made of porous oxides having a stable perovskite structure with good electric properties at high temperatures in an oxygen rich environment. Most widely used cathode materials are strontium-doped lanthanum manganite (LSM), cobaltite (LSC), ferrite (LSF) and cobalt ferrite (LSCF). Despite excellent electronic and ionic conduction properties and stability in oxidizing environments, cathode materials are not suit-able in the anode due to reduction by the fuel.[xxxv]

There are two basic SOFC geometries: planar and tubular.[xxxvi] In the planar geometry electrolyte is sandwiched between the electrodes in individual planar cells, which are placed side-by-side to form an SOFC stack. The main advantage of the planar structure is the current collection in series, and simplicity of the manufacturing process. However, the distribution of the fuel flow in the an-ode and the air flow in the cathode requires attention. Similarly, thermal stresses during transients can become major issues in the lifetime and the durability of the stack.

In the tubular design, the stack is formed by parallel construction of cylindrical tubes having the anodes inside and the cathodes outside and manufactured by ceramic extrusion process. Tubes are supported by a relatively thicker (*ca*. 200 μm) anode material, which is a mix of a ceramic material, typically YSZ with nickel, which serves as an electric conductor as well as a catalyst. The anode support is wrapped by thin shells (*ca*. 30-40 μm) of electrolyte and the cathode can be made very thin to improve the overall performance, efficiency and the power density of the cell. Flow distribution in the tubular designs is less of an issue than the planar ones as the tubes open to inlet and outlet manifolds that enable even distribution of reactants inside and outside the tubes. In addition, tubular designs are less prone to thermal stresses than the planar ones. However, the current collection requires elaborate wiring with high temperature resilient alloys such as Crofer 22 APU[xxxvii] inside and outside the tubes. In the tubular design, further improvements to power densi-ty and performance can be achieved as the diameter of the tube decreases. In micro-tubular SOFCs, the tube diameter can be smaller than 1 millimeter and up to a few millimeters. These de-signs are popular as range extenders for robots and aerial vehicles.[xxxviii]

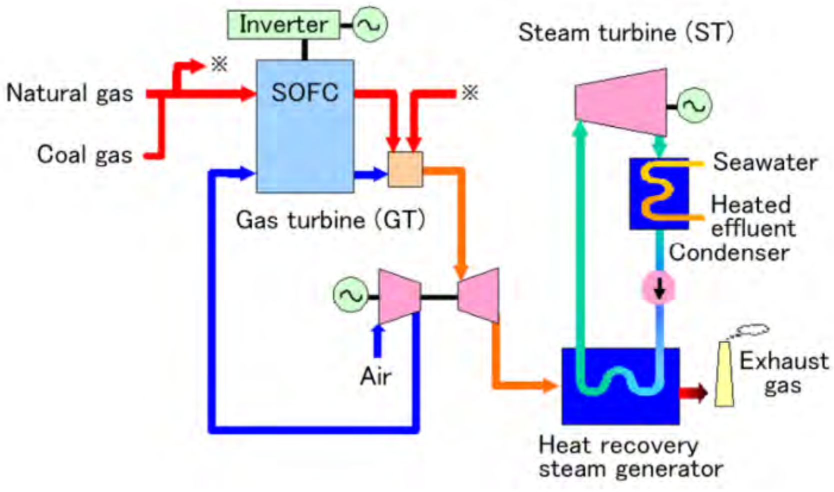
9. Triple Combined Cycle SOFC System

SOFC systems can use hydrocarbon fuels and operate at high temperatures similar to combustion-based power generation systems. In addition to higher efficiency of the SOFC system, CO_2 in the anode exhaust can be captured in downstream condensers since the fuel in the anode side and air in the cathode do not mix as they do in the combustion system. In order to avoid deleterious effects of fuel starvation, SOFC anodes operate fuel-rich. The unspent fuel in the exhaust can be burnt with pure oxygen to have CO_2 and H_2O as the only reaction products. As the water can be condensed at low cost, pure CO_2 can be pressurized and transported to a storage facility for long-term disposal. This process is much easier than the CO_2-capture in combustion-based power systems, which requires elaborate steps such as membrane gas separation, carbon scrubbing and chemical adsorption technologies for the separation of CO_2 from the flue gas.[xxxix]

In addition to stand-alone applications, hybridization of SOFC power systems with combustion systems such as a gas turbine (GT) and combined heat and power (CHP) applications are promising options that improve the overall efficiency and carbon-capture potential.[xl] There are several variants of the combination of the SOFC system with the heat engine, usually a GT. Typically, the SOFC acts as a part of the combustor unit, where compressed fuel is fed to anode and air or oxygen is fed to the cathode. Hydrogen from the catalytic oxidation at the inlet of the anode goes to electrochemical reaction in part and generates electricity in the SOFC. After the SOFC, direct combustion of unused fuel and excess hydrogen takes place in a combustor to provide additional heat and utilize all the available energy in the fuel-hydrogen mixture. Combustor exhaust contains only water vapor and carbon dioxide if oxygen is used in the cathode and sent to gas turbine to achieve additional work and electric output.

Several research studies on various combinations SOFC hybrid systems demonstrate that the over-all thermodynamic efficiency could be as high as 74% in this configuration. In addition to theoreti-cal analysis, Mitsubishi Heavy Industries (MHI) [xli] is one of the first companies who have explored the potentials of SOFC systems for large scale power generation since 1980s. In a joint project with New Energy and Industrial Technology Development Organization (NEDO), MHI successfully installed a 200-kW hybrid system featuring SOFC-micro GT technology in 2006 and conducted performance tests in 2007 demonstrating a power output of 229 kW-AC (with SOFC 204 kW/AC and 41 kW/AC with the micro GT) with an overall power efficiency of 52.1% based on lower heating value (LHV) of the fuel. Currently, the company is working to develop an 800-MW class triple combined cycle system, which integrates an SOFC with a utility GT and a steam turbine (ST) (see Figure 7). The SOFC-GT-ST system aims to achieve more than 70% power generation efficiency.[xlii]

Figure 7: Triple combined-cycle system



Siemens Westinghouse[xliii] developed and operated a 100-kW tubular SOFC with combined heat and power (SOFC-CHP) system over 29,000 hours with an electrical efficiency of 46% and devel-oping a 250-kW system operating at Kinetrics Inc. Facility (in Toronto, Canada) with an electrical efficiency close to 50%.

10. Cost Comparison of Current-Technology SOFCs and Natural Gas Turbines

Recently, SOFC hybrid power systems have received popularity in the literature as hybridization, especially with a gas turbine, that introduces additional opportunities such as improving system flexibility and increasing fuel cell lifetime. Extending the lifetime of fuel cells is crucial in SOFC technology since the cost of the stack is currently in the order of 2–3 k$/kW.[xliv] For SOFC systems to be economically competitive, lifetimes of 40,000-50,000 hours are required.[xlv] Battelle[xlvi] has reported the manufacturing costs of 1 kW and 5 kW SOFC for auxiliary power applications using high-volume manufacturing processes at various annual production rates. When the mass produc-tion is exercised, 50K units per year, the system cost of a 5kW SOFC with markup becomes $3,157/kW.

There are two prominent strategies to integrate SOFC with gas turbines: direct thermal coupling which includes at least two power systems (such as SOFC and GT) sharing the same working fluid, and indirect thermal coupling in which the working fluids are separated and only heat is transferred through heat exchange between power systems. Direct thermal coupling is considered as the best suited strategy to the combination of SOFC with GT.

While many of the SOFC-GT studies in the literature are analyzing direct thermal coupling, only a few prototypes of these hybrid systems are available due to the exorbitance cost of SOFC technol-ogy; thus, researchers have to rely on mathematical modeling and computer simulation[xlvii] to predict the performance of such systems.

Franzoni et al.[xlviii] modeled a plant in which carbon dioxide is separated. They found that condens-ing the exhaust steam, which enabled the separation of the CO_2 in the outlet, decreases the system efficiency by 2.8% (from 61.7 to 58.9%). Arsalis[xlix] performed a detailed thermo-economic as-sessment of a 1.5–10 MWe hybrid system and found that for small SOFCs cost minimization is the critical optimization goal, while for large SOFCs efficiency maximization is the main goal.

Thermo-economic analyses' goal is to maximize system efficiencies, minimize irreversibilities or maximize the cost benefit. Various optimization techniques have been practiced in the literature such as single-level modeling (aims to optimize the entire system as a whole) or multi-level model-ing (seeks to simultaneously optimize multiple subsystems).

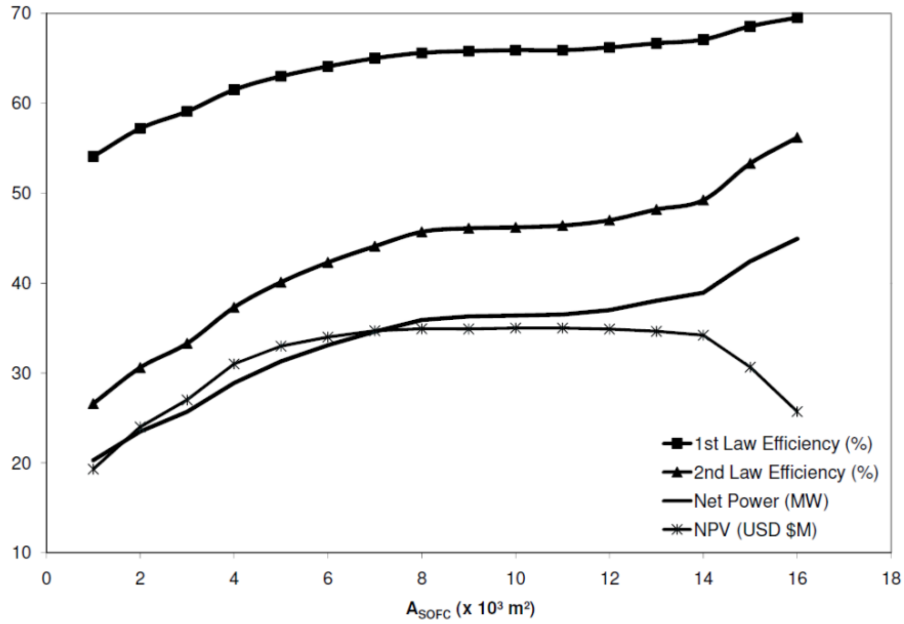
In conventional GT power plants, performances of the first and second law of thermodynamics are low as they are operating under the standard Brayton cycle, where heat input coming from com-bustion of carbon-based fuels. Conversely, SOFC technology provides better fuel utilization, *ca.* 75%, and better thermal efficiency.

To mitigate the low efficiencies in power plants that are operating on the Brayton cycle, Cheddie[l] investigates the effects of integrating a SOFC with a 10MW GT power plant. Although the cost of SOFC technology is still a prohibitive factor, the presented cost analysis in Cheddie's study was based on the projected mass production costs when the technology matures.

In the economic analysis, the author assumes the electricity price of USD $0.05/kWh and the fuel cost of USD $3.50/ MBTU for using natural gas (methane). All costs are converted to net present value (NPV) using a 9% interest rate over a 10-year life cycle. The optimization objective was to discover the optimum SOFC size by which the NPV is maximized, while supplying sufficient fuel to keep a turbine inlet temperature of 1,400 K.

As the SOFC size increases, the plant efficiency increases asymptotically whereas the capital cost increases almost linearly with SOFC size. Thus, the NPV forms a curve with a peak. By looking at Figure 8, one can see that the NPV reaches a peak of $34.9 M when a 7,000 m^2 cell is used. How-ever, 8000 m^2 is considered to be the optimal size of the SOFC unit required to best match the gas turbine. Efficiencies corresponding to the first and second law for the 8,000 m^2 cell are 66.2% and 47.0%, respectively. In the mentioned hybrid plant, 23.4 MW out of 37.0 MW is produced by the SOFC component.

Figure 8: Optimization of the SOFC-GT system with respect to NPV



All capital costs and payback periods are shown in Table 3. Note that these numbers only include the cost of adding the SOFC to the power plant. The combustor, turbine and compressors already exist, thus their costs are not taken into account. The fuel cost refers to the annual cost of addition-al fuel required for the hybrid plant.

Table 3: Cost breakdown for the hybrid plant (USD $M).

Component	Capital Cost	Annual Gain (Cost)
SOFC Stack	20.1	-
Inverter	1.5	-
Pre-reformer	0.2	-
SOFC Auxiliary	2.0	-
SOFC Total	23.8	-
Heat Exchangers	2.3	-
Fuel Costs	-	(2.3)
Power Gains	-	11.9
NPV	34.9	-
Payback Period	3.3 years	-

The hybrid power plant generates almost four times as much power as the original GT power plant. As a point of comparison, the entire 37-MW hybrid system would cost $32 M, while an equivalent GT power plant would cost $9.6 M to produce only 17 MW. All in all, the SOFC hybrid system can decrease the cost of energy to $0.033/kWh compared to $0.05/kWh for an equivalent GT sys-tem.

Zaccaria et al.[li] performed economic analysis by comparing a stand-alone, atmospheric SOFC sys-tem with a pressurized SOFC gas turbine hybrid. They assume a feed-in tariff (0.14 $/kWh) to fa-vor an early market penetration of SOFC systems. In their hybrid system, authors assume the stack has to be replaced when the gas turbine reached design power condition. For the stack cost, an optimistic value has been considered[4]. Other economic assumptions/parameters are listed in Table 4.

[4] In 1999, the turbines program funded a study by Rolls Royce with the goal to produce a turbo-generator, which would cost approximately $400/kW.

Table 4: Economic assumptions

Component	Cost
SOFC Stack	400 $/kW for a stack size of 330 kW
Gas turbine	700 $/kW
Exhaust gas recuperator	50% turbine cost
SOFC blower	10% stack cost
SOFC inverter	10% stack cost
Annual maintenance	3% capital investment
Electricity price (feed-in tariff)	0.14 $/kWh
Fuel price	0.1 $/kg
Discount rate (to actualize cash flow)	0.01

The outcome of analysis proposes that the stand-alone stack is at its most economically advanta-geous situation when the initial current is at 0.2 A/cm^2. Further reducing the power density, pay-back period (PBP) started increasing again, indicating that there is an optimal value of current from an economic point of view. Finally, with a stack cost of $132,000, 0.5 A/cm^2 was not economically feasible since the cash flows were negative throughout the system lifetime.

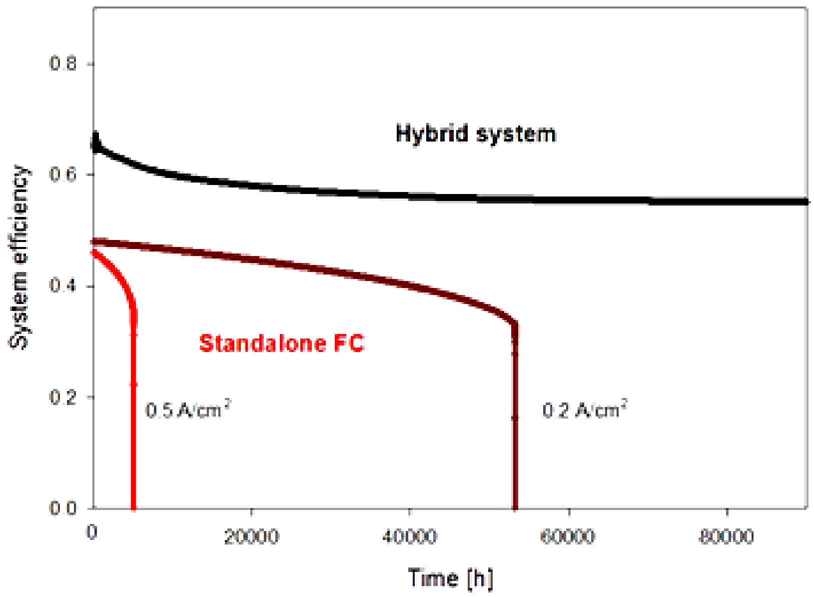
If the stack cost increased to 1,000 $/kW at 0.5 A/cm^2, for a total cost of $330,000, only the two cases at lowest current density gave a positive PBP, equal to 53 years for 0.2 A/cm^2 and 91 years for 0.1 A/cm^2. In that scenario, the NPV at 20 years would be negative, respectively −74% and −78% of the initial capital cost (which is now approximately three times higher). At the current stack price of 3,000 $/kW, which brings the total cost to $990,000, would not provide positive PBP or NPV for any current density.

Table 5: PBP, NPV, and IRR for the stand-alone stack at constant power with different initial current densities.

Initial current density (A/cm2)	Lifetime (yr)	Payback period (yr)	NPV (% capital cost)	Internal rate of return
0.5	0.7	-	-538	-0.075
0.4	1.3	26.5	-1.5	0.165
0.3	2.5	7.3	114.2	0.188
0.2	6	6.3	181	0.214
0.1	11.2	11.2	63.8	0.106

However, combining SOFC and gas turbine has improved the resulted hybrid system's cost and performance, insomuch as the project becomes economically feasible, even at the current stack price of $3000/kW. This outcome is in line with findings of Cheddie .[lii] In Figure 9, the system efficiency through lifetime is compared for the hybrid and stand-alone configurations.

Figure 9: Effect of hybridization with a GT on the system lifetime.



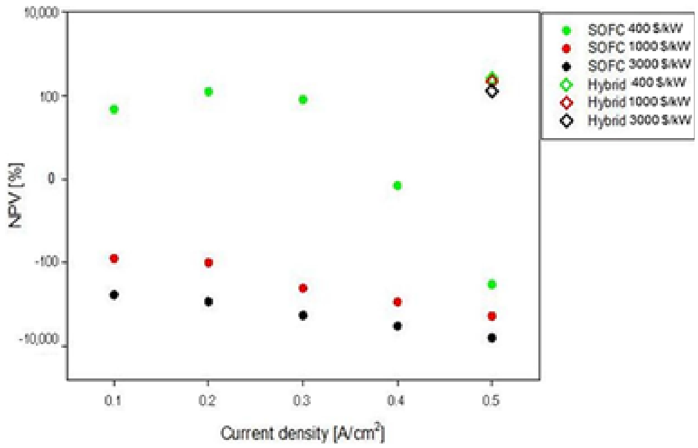
In the hybrid system, the results were not significantly affected by the stack cost. This is due to the stack being replaced once every 11 years and the contribution of gas turbine on the total power production and system efficiency. The PBP is halved in a hybrid configuration with respect to the most advantageous stand-alone case. The very low dependence on stack cost indicates that an early adoption of SOFC technology would be possible at current cost and voltage degradation rate, thanks to the hybridization with gas turbine systems.

Table 6: PBP, NPV, and IRR for the hybrid system.

Stack cost	Stack lifetime (year)	Payback period (year)	NPV (% capital cost)	Internal rate of return
400 $/kW	11.3	2.9	416	0.33
1,000 $/kW		3.3	365	0.29
3,000 $/kW		5.2	189	0.21

Figure 10 demonstrates that stand-alone configuration is only economically feasible if the cost of SOFC stack is $400/kW. On the other hand, hybridizing SOFC with GT helps the combined sys-tem to be practical even with the current stack cost ($3,000).

Figure 10: NPV trends for stand-alone SOFC and hybrid system with different stack costs.



Meratizaman et al.[liii] have investigated the techno-economic advantage of using SOFC-GT tech-nology for residential sector (buildings with 4 floors and 100 m^2 flat in each floor). They conclude that employing the proposed system in a hot and humid area is more economical with a faster peri-od of return (8.35 years instead of 10.55 years in a colder city).

Rokni [liv] compared the performance of an imaginary repowered steam power plant using different strategies: repowering with a single GT, repowering with two GTs with and without Supplemen-tary Firing (SF) and finally repowering with SOFC. Interestingly, the cost analysis shows that re-powering steam power plant with SOFC and hybrid recuperator (HR) is cheaper than using two Siemens SGT5 4000F GTs with small supplementary firing.

Table 7: Total cost of additional required components for repowering.

Plant Configuration	Net Power (MW)	Efficiency (%)	CO2 Emission (kg CO2/ kWhe)	Total Cost ($)	Cost ($/kW)
Repowered plant with 1 GT	569	47.76	0.44	54,131,342	95
Repowered plant with 2 GT	860	52.88	0.39	108,621,716	126
Repowered plant with SOFC and HR	1003	60.55	0.35	119,863,704	120

In 2008, Arsails [lv] developed thermo-economic model of a hybrid power plant using a tabular Sie-mens-Westinghouse-type SOFC with a GT and a ST ranging from 1.5 to 10 MWe. The author con-siders four different ST cycles: a single-pressure, a dual-pressure, a triple pressure, and a triple pressure with reheat. Moreover, the SOFC cell size is examined. The modelled SOFC-GT-ST hy-brid system exhibits better efficiencies (maximum efficiency of 73.8%) that cannot be compared with stand-alone SOFC or SOFC-GT hybrid cycles. The parametric study also revealed some complexities including finding a proper SOFC stack size and proper ST to match the system since GT and ST tend to be inefficient at small scales (e.g., 1.5 MWe).

Sadeghi[lvi] compared two hybrid systems, SOFC-GT and SOFC-GT-ST, with respect to efficiency and the levelized cost of energy (LCOE). Results show that SOFC-GT-ST provides the cheapest electricity per kWh when SOFC input temperature is low (1000 K).

Table 8: Optimization results according to efficiency.

	SOFC input tempera-ture (K)	Effi-ciency	Annualized Cost ($/year)	Power Gen-eration (kWh/year)	LCOE ($/kWh)	Fuel Heat Exchangers mid-tempera-ture (K)	Water Heat Exchangers mid-tempera-ture (K)	Air Heat Exchangers mid-tempera-ture (K)
SOFC-GT	1000	0.543	280,584	14,767,187	0.0190	976	769	990
	1100	0.583	299,870	15,723,885	0.0191	920	937	1088
	1150	0.590	309,630	15,932,997	0.0193	918	1033	1094
SOFC-GT-ST	1000	0.566	290,949	15,580,752	0.0186	848	963	986
	1100	0.596	307,999	16,392,890	0.0187	972	856	1063
	1150	0.599	316,707	16,460,685	0.0192	1092	1012	1099

11. Pathways to Cost Competitive SOFCs

SOFCs have been under investigation for decades, and they are providing higher efficiency vis-à-vis conventional combustion methods. However, its application in the market is confined due to high investment costs and limited lifetime. In this section, we highlight research directions that enhance SOFCs economic viability.

- **Decreasing Costs**

The current manufacturing cost of SOFC stacks is making this technology hard to recom-mend. Nonetheless, we expect the stack cost to decrease through time by R&D.
Meanwhile, to increase the market penetration and make use of endogenous technology learning (ETL), it is better to combine SOFCs with gas turbines. By doing so, the economic performance and funding of the entire SOFC supply chain is improved. This pull mecha-nism ends up with research at universities and research centers, and therefore, decrease the standalone systems' costs.

- **Increasing Lifetime**

SOFCs suffer from a short lifetime (40,000 – 60,000 hours). This short lifetime is due to a progressive performance degradation that leads to cell failure. Also, the brittle nature of ce-ramics makes them vulnerable to fractures caused by mechanical and thermal stresses; therefore, slight pressure or temperature differences especially in planar design can break the ceramic, leading to cell failure. This physical weakness is critical to investors since it limits the flexibility of the power plant to shut down and start upon demand.

The robustness can be improved by arranging anode, electrolyte, and cathode in tubular form[lvii] . Tubular SOFCs have demonstrated great longevity, thermal cycling robustness, and negligible performance degradation over several years of operation.[lviii] However, this design is harder to produce, and thus, increases the fabrication cost.

- **Decreasing Operating Temperature**

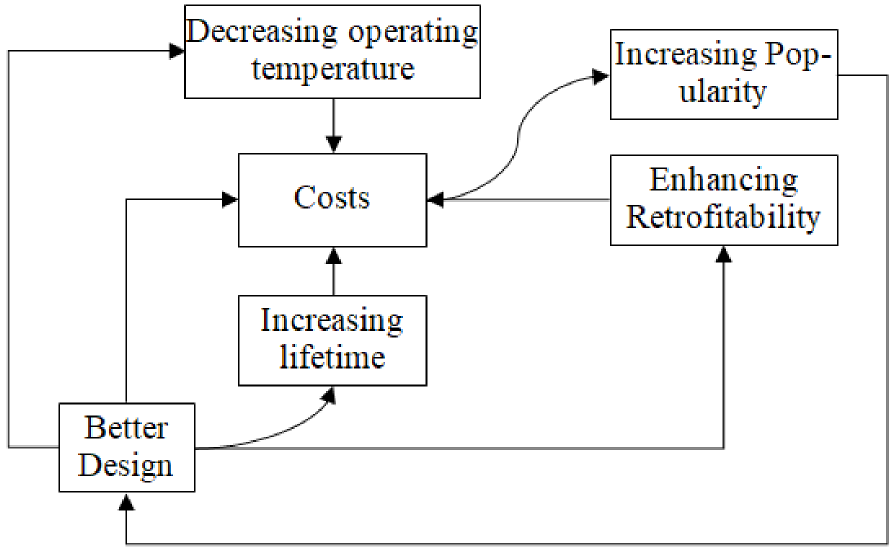
SOFCs are working at high temperature (600 – 1000 °C). Achieving lower operating tem-perature can simplify the design to a great extent. Issues such as materials instability and interfacial reactions occur less at lower temperatures. Expensive high-temperature materials can be replaced with conventional materials. In planar SOFCs, gas sealing becomes simpler. Moreover, reducing the operating temperature shortens the start-up time, and it reduces the degradation effects of thermal cycling. Finally, low-temperature operation allows better integration with the fuel processing and air preheating parts of the system.[lix] However, several limiting factors prevent us from achieving low-temperature SOFCs including the cathode polarization resistance and fuel oxidation on the anode. Because of mentioned lim-iting factors, the low-temperature operation range appears to be between 500 and 700°C. More research has to be undertaken to address the limiting factors and to further decrease the operating temperature.

- **Enhancing Retrofitability**

Retrofitting existing power plants will mark a significant step toward the widespread appli-cation of SOFC in the near future. Research should be done to understand and assess chal-lenges in retrofitting SOFC stack modules in existing power plants. It is crucial to evaluate power plant off-design performance, required process modifications and operational boundaries based on the existing equipment in the power plant.[lx] Multiple challenges exist to retrofit syngas fed SOFCs in existing power plants like cost, process design, material availability, contaminant tolerance, carbon deposition. [lxi] SOFC systems that are plug-and-play can decrease the overall design cost, improving economic viability.

Figure 11 summarizes the mentioned points in this section. As can be seen in the figure, the high investment cost is the major hindering factor in the popularity of SOFC technology. To lower the cost, more effort has to be put into the design: finding better materials; inventing better mechanical structure; and designing better manufacturing process. Better designs pave the way for decreasing the investment cost and operating temperature, increase system lifetime and enhance retrofitability. As a direct result of better design, the popularity of SOFC technology increases, and through ETL and more investments better designs will be created.

Figure 11: Summarizing all major factors in the success of the SOFC system. All links have positive effects.



The good news is that industry and government research agencies are conducting significant re-search to achieve these goals. To illustrate this, the U.S. Department of Energy provided, during 2016, over $12 million in grants to develop robust SOFC stacks, highly selective and stable multi-variable gas sensors, improvements in electrolyte reliability, low-temperature operation and trans-formative SOFC technology. The European Commission has also sponsored projects such as cost effective and flexible 3-D printed stacks and next-generation SOFCs. Japan's New Energy and Industrial Technology Development Organization (NEDO) has launched a demonstration test of a SOFC in Osaka and supported research on SOFC reliability. More important, industry will be ready consumers of these government-supported technological advances to improve their existing SOFC products and introduce them to new markets.

12. Capturing and Transporting CO_2 From Load-Following Power Plants

Before leaving an unrealistically optimistic outlook for the prospects for carbon capture and transport from fossil fuels and natural gas in particular, it should be mentioned that the increasing use of variable renewables and distributed generation may diminish the future role of the baseload power plant. Most analyses of CCUS inherently assume a baseload power plant as they typically assume a steady flow of captured CO_2 for pressurization, pipeline transport and injection. Frequent interruptions in CO_2 output would substantially complicate the technical problem of transporting CO_2 from the power plant to storage or use.

Unless battery or other electric storage systems can preserve a continued role for baseload power plants, there will be an increased incentive to operate fossil fuel plants, especially natural gas plants that have relatively high fuel costs compared to capital costs, in load following modes. This may reduce the practical application of CCS to a more limited number of older baseload coal plants that are incapable of load following (although these are more likely to be the worst candidates for retrofitting carbon capture). For natural gas, this is a more acute problem and needs to be taken into account when assessing the application of CCS to natural gas. The hybrid natural gas systems described in this paper aim for high efficiency and the increased capital cost to achieve this tends to be justified in baseload power plants. It is also noted that the cost analysis in the paper does not account for any technical solutions that may be available to permit CO_2 for pressurization, pipeline transport and injection from load-following power plants.

This caution is not intended to suggest that the trends in the modern electric grid and the likelihood of more load following are an insurmountable problem to the prospects of carbon capture for natural gas or that the approach suggested in this paper, hybrid systems employing SOFCs, will not work. The issue is raised to make it clear that the potential problem exists even though it is beyond the scope of this paper.

13. Achieving Climate Goals with Solid Oxide Fuel Cells: Policy Recommendations

Governments should give increased priority to achieving carbon capture from natural gas because the expected world-wide growth of natural gas use is considerably larger than the world-wide growth of coal.[lxii] These well-founded expectations should cause energy and climate policy makers to abandon the notion that natural gas is a "transition fuel," whose use will rapidly diminish as the imperative to reduce GHG emissions increase and as natural gas becomes more expensive due to limited supplies. As discussed above, the supplies of competitive natural gas are likely to extend well beyond the period where energy-sector GHG emissions have to be greatly reduced. The combustion of the projected natural gas use by the IEA, without CCS, is not compatible with re-ducing emissions sufficiently to achieve a sustainable energy sector.

As the cost of carbon separation from natural gas, using the current conventional power generating technology, is much higher than carbon separation from coal, and too high for natural gas to be a competitive power-generating fuel (see Section 6 above), an alternative approach is needed to ap-ply CCS to natural gas. The leading alternative approach is the SOFC. SOFCs are the leading alternative approach because 1) their emissions of CO_2 without CCS are relatively low (high efficiency, especially with co-generation); and 2) CO_2 is only comingled with water and unreacted CH_4 resulting in low-cost separation of CO_2. The efficiency losses are minimal compared to the significant efficiency losses when CCS is applied to coal power plants or natural gas turbines.

The primary barrier to the uptake of CCS with SOFCs is the development of a grid-scale SOFC with comparable cost and reliability of natural gas turbines. If SOFCs were a competitive grid scale technology in its own right, quite apart from the ease with which they can be fitted with CCS technology, then the additional cost of CCS would be *de minimis* compared to the cost-prohibitive CCS technologies that are available for coal power plants and natural gas turbines.

While the current research to achieve cost-competitive and reliable SOFCs for grid-scale applica-tion is encouraging, these efforts should be significantly increased in order to achieve more rapid technology development and the opportunity to achieve grid-scale commercial application, a nec-essary step that enables further cost reduction (technology learning, or, learning by doing).

References

[i] Zhu, Lin, Yangdong He, Luling Li, Pengbin Wu, "Tech-economic assessment of second generation CCS: Chemical looping combustion, Energy, Volume 144, 2018, pp 915-927

[ii] International Energy Agency, *Energy Technology Perspectives* 2017, June 2017

[iii] International Energy Agency, *World Energy Outlook 2019*, Paris, November, 2019

[iv] International Energy Agency, *World Energy Outlook 2019*, Paris, November, 2019

[v] International Energy Agency, *World Energy Outlook 2019*, Paris, November, 2019

[vi] International Energy Agency, *World Energy Outlook 2019*, Paris, November, 2019

[vii] Stram, Bruce, "Key Challenges to Expanding Renewable Energy, *Energy Policy*, Vol. 96, pp 728-734, 2016

[viii] Khatib, H and Carmine Difiglio, "Economics of Nuclear and Renewables, *Energy Policy*, Vol. 96, pp 740-750, 2016

[ix] "Current Policy Scenario," International Energy Agency, *World Energy Outlook 2019*, Paris, November, 2019

[x] International Energy Agency, *World Energy Outlook 2019*, Paris, November, 2019

[xi] Gençer, Emre, "Exploring the Rapidly Changing Energy System, *IICEC Energy and Climate Research Paper*, Sep-tember 2019, https://iicec.sabanciuniv.edu/sites/iicec.sabanciuniv.edu/files/iicec_research_egencer_2_0.pdf

[xii] Kanniche, M., Gros-Bonnivard, R., Jaud, P., Valle-Marcos, J., Amann, J. M., & Bouallou, C., Pre-combustion, post-combustion and oxy-combustion in thermal power plant for CO_2 capture. *Applied Thermal Engineering*, 30(1), 53-62, 2010

[xiii] Source of Figure 2: National Energy Technology Laboratory, Chemical Looping Combustion, https://www.netl.doe.gov/research/coal/energy-systems/advanced-combustion/clc

[xiv] Kanniche, M., Gros-Bonnivard, R., Jaud, P., Valle-Marcos, J., Amann, J. M., & Bouallou, C., Pre-combustion, post-combustion and oxy-combustion in thermal power plant for CO_2 capture. *Applied Thermal Engineering*, 30(1), 53-62, 2010

[xv] Elwell, L. C., & Grant, W. S.. Technology options for capturing CO_2, *Power Magazine*, 150(8), 60, 2006

[xvi] Bjorn Nykvist, "Ten times more difficult, Quantifying the carbon capture and storage challenge," *Energy Policy*, vol. 55 pp. 683-639, 2013

[xvii] Steen M. Greenhouse gas emissions from fossil fuel fired power generation systems. *Institute for Advanced Materials, Joint Research Centre, European Commission,* 2000

[xviii] IEA, *Resources to Reserves,* Paris, 2013, p. 176

[xix] U.S. EIA, *World Shale Resource Assessment,* September 24, 2015

[xx] IEA, *World Energy Outlook 2016,* Paris, 2016, p. 181

[xxi] IEA, *World Energy Outlook 2016,* Paris, 2016, p. 249

[xxii] *Modern Power Systems*, 2008
E.On UKm 2007

[xxiii] GHG, IEA. CO_2 capture as a factor in power station investment decisions, IEA GHG (IEA Greenhouse Gas R&D Programme) Report 2006/8, 2006.

[xxiv] https://www.bloomenergy.com/solutions/energy-server-platform

[xxv] http://www.bosch-presse.de/pressportal/de/en/bosch-presents-power-generating-heating-system-based-on-fuel-cell-technology-42124.html

[xxvi] http://convion.fi/products/

[xxvii] http://www.elcogen.com/#network.

[xxviii] https://www.mhps.com/products/sofc/

[xxix] https://www.energy.gov/fe/why-sofc-technology

[xxx] Kendall, S. C. (2003). High temperature solid oxide fuel cells: fundamentals, design and appslications. Oxford.

[xxxi] Adams, Thomas A, Jake Nease, David Tucker, and Paul I Barton. "Energy Conversion with Solid Oxide Fuel Cell Systems: A Review of Concepts and Outlooks for the Short- and Long-Term." Industrial & Engineering Chemistry Research 52(9): 3089–3111. http://dx.doi.org/10.1021/ie300996r, 2013.

[xxxii] Electrochemical Society Interface, Fall 2009

[xxxiii] Adams et al, 2013

[xxxiv] Goodenough, J. (2000). Ceramic technology: oxide-ion conductors by design. Nature, 821-3.

[xxxv] J. Hanna, W. L. (2014). Fundamentals of electro- and thermochemistry in the anode of solid-oxide fuel cells with hydrocarbon and syngas fuels. Progress in Energy and Combustion Science, 74-111.

[xxxvi] Buonomano, Annamaria et al. 2015. "Hybrid Solid Oxide Fuel Cells-Gas Turbine Systems for Combined Heat and Power: A Review." Applied Energy 156: 32–85. http://dx.doi.org/10.1016/j.apenergy.2015.06.027.

[xxxvii] Przybylski, Kazimierz et al. 2014. "Oxidation Properties of the Crofer 22 APU Steel Coated with La0.6Sr0.4Co0.2Fe0.8O3 for IT-SOFC Interconnect Applications." Journal of Thermal Analysis and Calorimetry 116(2): 825–34. http://link.springer.com/10.1007/s10973-013-3594-1.

[xxxviii] Kendall, K, B Liang, and M Kendall, "Microtubular SOFC (mSOFC) System in Mobile Robot Applications" ECS Transactions 78(1): 237–42, 2017.

[xxxix] Tan, Yuting et al., "Property Impacts on Carbon Capture and Storage (CCS) Processes: A Review." *Energy Conversion and Management* 118: 204–22. http://dx.doi.org/10.1016/j.enconman.2016.03.079. 2016

[xl] Fuel Cell Handbook, seventh ed., Office of Fossil Energy, National Energy Technology Laboratory, Morgantown, West Virginia, November, 2004.

[xli] Kobayashi, Yoshimuro et al. "Recent Progress of SOFC-GT Combined System with Tubular Type Cell Stack at MHI," ECS Transactions, 57 (1), 2013.

[xlii] Kobayashi, Yoshimuro et al. "Extremely high-efficiency thermal power system-solid oxide fuel cell (SOFC) triple combined-cycle system." *Mitsubishi Heavy Industries Technical Review* 48 (3): 9-15, 2011

[xliii] "Siemens celebrates one-year anniversary of SOFC generator in Italy," Fuel Cells Bull. September (2006)

[xliv] Colantoni, Andrea, et al. "Economical analysis of SOFC system for power production." *Computational Science and Its Applications*-ICCSA 2011: 270-276. 2011

[xlv] Hawkes Adam and Brett Dan, "Fuel Cells for Stationary Applications", IEA ETSAP, 2013

[xlvi] Battelle, "Manufacturing Cost Analysis of 1 kW and 5 kW Solid Oxide Fuel Cell (SOFC) for Auxiliary Power Ap-plications", *U.S. Department of Energy*, DOE Contract No. DE-EE0005250, 2014

[xlvii] Bao, Cheng, et al. "Multi-level simulation platform of SOFC–GT hybrid generation system." *international journal of hydrogen energy* 35(7): 2894-2899. 2010

[xlviii] IFranzoni, A., et al. "Thermoeconomic analysis of pressurized hybrid SOFC systems with CO 2 separation." *Energy* 33(2): 311-320. 2008

[xlix] Arsalis A. "Thermoeconomic modeling and parametric study of hybrid SOFC–gas turbine–steam turbine power plants ranging from 1.5 to 10MWe." *Journal of Power Sources* 181(2): 313-26. 2008

[l] Cheddie, Denver F. "Integration of a solid oxide fuel cell into a 10 MW gas turbine power plant." *Energies* 3.4: 754-769. 2010

[li] Zaccaria, Valentina et al. "Gas turbine advanced power systems to improve solid oxide fuel cell economic viability." *Journal of the Global Power and Propulsion Society* 1 (2017): U96IED.

[lii] Cheddie, Denver F. "Integration of a solid oxide fuel cell into a 10 MW gas turbine power plant." *Energies* 3.4: 754-769. 2010

[liii] Meratizaman, Mousa, Sina Monadizadeh, and Majid Amidpour. "Techno-economic assessment of high efficient energy production (SOFC-GT) for residential application from natural gas." *Journal of Natural Gas Science and Engineering* 21: 118-133. 2014

[liv] Rokni, Masoud. "Performance comparison on repowering of a steam power plant with gas turbines and Solid Oxide Fuel Cells." *Energies* 9.6: 399. (2016)

[lv] Arsalis A. "Thermoeconomic modeling and parametric study of hybrid SOFC–gas turbine–steam turbine power plants ranging from 1.5 to 10MWe." *Journal of Power Sources* 181(2): 313-26. 2008

[lvi] Sadeghi, S. "Multi-objective optimization of two hybrid power generation systems for optimum selection of SOFC reactants heat exchangers mid-temperatures." *Iranian Journal of Hydrogen & Fuel Cell 3* (2017): 175-188.

[lvii] J. Milewski, & W. Budzianowski, "Recent key technical barriers in solid oxide fuel cell technology" *Archives of Thermodynamics, 35*(1): 17-41, (2014).

[lviii] DiGiuseppe, G., "High power density cell development at Siemens Westinghouse" Solid Oxide Fuel Cells IX, SC Singhal and J. Mizusaki, eds., The Electrochemical Society Proceedings Series, Pennington, NJ, 322–332, (2005).

[lix] Carter, J. D., Cruse, T. A., Ingram, B. J., & Krumpelt, M., "Factors limiting the low temperature operation of SOFCs". Handbook of Fuel Cells (2010).

[lx] A. T. Thattai, V. D. W. M. Oldenbroek, L. Schoenmakers, T. Woudstra, & P.V. Aravind, "Towards retrofitting inte-grated gasification combined cycle (IGCC) power plants with solid oxide fuel cells (SOFC) and CO_2 capture–A ther-modynamic case study" *Applied Thermal Engineering.* 114:170-185, (2017).

[lxi] T. M. Gür, "Comprehensive review of methane conversion in solid oxide fuel cells: prospects for efficient electricity generation from natural gas". *Progress in Energy and Combustion Science*. 54:1-64, (2016).

[lxii] IEA, *World Energy Outlook 2016,* Paris, 2016, p. 249