

The role of natural gas and its infrastructure in mitigating greenhouse gas emissions, improving regional air quality, and renewable resource integration



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ABSTRACT

The pursuit of future energy systems that can meet electricity demands while supporting the attainment of societal environment goals, including mitigating climate change and reducing pollution in the air, has led to questions regarding the viability of continued use of natural gas. Natural gas use, particularly for electricity generation, has increased in recent years due to enhanced resource availability from non-traditional reserves and pressure to reduce greenhouse gasses (GHG) from higher-emitting sources, including coal generation. While lower than coal emissions, current natural gas power generation strategies primarily utilize combustion with higher emissions of GHG and criteria pollutants than other low-carbon generation options, including renewable resources. Furthermore, emissions from life cycle stages of natural gas production and distribution can have additional detrimental GHG and air quality (AQ) impacts. On the other hand, natural gas power generation can play an important role in supporting renewable resource integration by (1) providing essential load balancing services, and (2) supporting the use of gaseous renewable fuels through the existing infrastructure of the natural gas system. Additionally, advanced technologies and strategies including fuel cells and combined cooling heating and power (CCHP) systems can facilitate natural gas generation with low emissions and high efficiencies. Thus, the role of natural gas generation in the context of GHG mitigation and AQ improvement is complex and multi-faceted, requiring consideration of more than simple quantification of total or net emissions. If appropriately constructed and managed, natural gas generation could support and advance sustainable and renewable energy. In this paper, a review of the literature regarding emissions from natural gas with a focus on power generation is conducted and discussed in the context of GHG and AQ impacts. In addition, a pathway forward is proposed for natural gas generation and infrastructure to maximize environmental benefits and support renewable resources in the attainment of emission reductions.

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1. Introduction and background

The current interchange between energy and the environment is prompting fundamental shifts in societal management of energy systems, including electricity generation. Climatic change by anthropogenic emissions of greenhouse gases (GHG) is perhaps the most important driver of environmentally-influenced societal change [1]. Deep reductions in GHG emissions (e.g., 50 to 80% below 2005 levels by 2050) are being required from developed nations for prevention of detrimental climate impacts [2,3]. Of similar concern, pollution in the air is expected to be the single largest global cause of environmentally-related premature mortality by 2050 [4]. Many regions of the United States (U.S.) experience air quality (AQ) challenges with atmospheric concentrations in excess of Federal health-based standards; and reducing pollutants such as ground-level ozone and particulate matter (PM) is necessary to improve public health [5]. Emphasizing the scale of necessary displacement, note that stabilizing the climate may require the complete de-carbonization of energy sectors [6]. Hence, technological and fuel shifts that can contribute to both GHG mitigation and regional AQ improvement represent good solutions for energy systems [7,8].

Electricity generation will likely receive a major focus in future U.S. GHG mitigation policies (perhaps even disproportionately relative to other sectors) because (1) it is currently the highest GHG emitting sector in the U.S. [9], (2) many alternative strategies exist to generate electricity with little to no GHG emissions [10], (3) electrification in additional end-use sectors (i.e., transportation, industrial, building demands) achieves GHG reductions if the electricity is decarbonized [11], and (4) emissions from many sources (e.g., large capacity generators) are concentrated and more suitable for emissions control applications, including carbon capture and storage (CCS) [12]. It is clear then that any meaningful U.S. GHG mitigation effort must have mechanisms to institute extensive changes to existing electrical supply chains in pursuit of emission reductions – including regulating carbon dioxide (CO₂) emissions from existing and future power plants [13].

Electricity generation also contributes to regional AQ concerns, including ground-level concentrations of pollutant species such as ozone and fine particulate matter (PM_{2.5}) [14]. Combustion processes and other life cycle stages associated with conventional technologies and fossil fuels, including natural gas, result in atmospheric releases of gaseous and particulate pollutants; including nitrogen oxides (NO_x), sulfur dioxide (SO₂), volatile organic compounds (VOC), carbon monoxide (CO) and particulate matter (PM) [15]. For example, stationary fossil fuel combustion for electricity is by far and away the largest source of domestic anthropogenic SO₂ [9]. It follows then that emissions of GHGs and pollutant species are highly correlated as a result of shared generation sources and processes. Thus, an important opportunity exists to simultaneously address U.S. GHG and AQ concerns by deploying alternative, low emitting generation strategies. Conversely, pursuit of GHG mitigation must seek to avoid unforeseen tradeoffs with pollutant emissions, and vice versa.

In this context, it is generally agreed that increasing renewable electricity generation (including from solar, wind, geothermal, ocean, hydropower and biopower resources) is necessary to satisfactorily meet demands commensurate with achieving environmental

quality goals [16]. Given the challenge of sufficiently decarbonizing energy systems to meet long-term GHG goals, assessments generally show that we must replace natural gas (and all other fossil fuels) at high levels – both with electrification in end-use sectors and with renewable resources for electricity generation (e.g., see [11,17–19]). Renewable technologies are often proposed as replacements for fossil power generation, including natural gas, as they are perhaps the best solution for electricity generation [20]. Some have suggested the immediate displacement of natural gas generation to avoid GHG-producing technology lock-in [20]. Additional low-carbon technologies commonly considered for GHG mitigation include energy storage to address the controllability and intermittency of renewable power generation, various forms of nuclear energy, fossil generation equipped with CCS, and methods to reduce demand via improvements in the efficiency of generation, transmission, distribution and end-use.

However, the role of natural gas is somewhat unique in that it can represent both a means of obtaining carbon reductions, and an essential target for displacement with lower-carbon alternatives, depending upon the considered sector and strategy and the dynamics of operation. While it is generally accepted that shifts away from coal and petroleum are required for significant emissions mitigation (or the deployment of additional measures such as CCS), the potential role of natural gas infrastructure in a future sustainable energy supply is less clear. Current natural gas electricity generation strategies primarily utilize combustion, which generates emissions of both pollutants and GHG, while the natural gas system directly emits GHG, primarily methane. Still others have warned against the utility of natural gas as a bridging fuel since it may slow the development of needed advanced, “ending” technologies [21] or represent an unacceptable environmental risk when resources are obtained from unconventional resources [22]. The concerns over natural gas generation are amplified by increasing awareness of significant methane emissions from the natural gas system, concerns that were heightened by the recent occurrence of a major leakage event in California [23].

On the other hand, natural gas can potentially represent a cleaner and more efficient fuel relative to other fossil options (e.g., coal, petroleum) and direct replacement can have immediate emission benefits,¹ e.g., increases in gas generation have recently led to reductions in total domestic GHG emissions [24]. Due to this, natural gas has been advocated for as an effective short- to mid-term “bridge” fuel to a low-carbon future, most notably in the context of providing a cost-effective option for displacing coal-fired power plants [25–27]. Further, natural gas is a cost-effective and established energy source with many applications in various energy sectors including power generation, transportation, industry, and the built environment. Natural gas currently represents an important component of the U.S. energy system amongst all sectors with the exception of transportation. The use of natural gas in the U.S. has steadily increased in the last decade – mirroring the rise in availability of unconventional reserves – and the trend is expected to continue in

¹ This is in-part because natural gas is predominantly composed of methane which has the lowest carbon to hydrogen ratio of commonly used fossil fuels and in-part because of the high efficiency and low emissions characteristics of modern natural gas combined cycle power plants

Nomenclature

Glossary

AC	Alternating Current
AD	Anaerobic Digestion
AFC	Alkaline Fuel Cell
AQ	Air Quality
A-USC	Advanced Ultra-supercritical
BACT	Best Available Control Technology
BIGCC	Biomass Integrated Gasification Combined Cycle
CA	California
CC	Combined Cycle
CCHP	Combined Cooling, Heating, and Power
CCS	Carbon Capture and Sequestration
CFBC	Circulating Fluidized Bed Combustion
CH₄	Methane
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO₂	Carbon Dioxide
CO₂e	Carbon Dioxide Equivalents
CSP	Concentrated Solar Power
CT	Combustion Turbine
DC	Direct Current
DEC	Dedicated Energy Crop
DG	Distributed Generation
EGS	Enhanced Geothermal System
ERCOT	Electric Reliability Council of Texas
FBC	Fluidized Bed Combustion
FC	Fuel Cell
GHG	Greenhouse Gas
GT	Gas Turbine
GW	Gigawatt
GWP	Global Warming Potential
HAP	Hazardous Air Pollutant
HHV	Higher Heating Value
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle
IGFC	Integrated Gasification Fuel Cell System
KW	Kilowatt
kWh	Kilowatt-hour
LCA	Life Cycle Assessment
LF	Load Following
LFG	Landfill Gas
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LNGCT	Liquefied Natural Gas Combustion Turbine
LPG	Liquefied Petroleum Gas
MCFC	Molten Carbonate Fuel Cell
MJ	Mega joule
MMT	Million Metric Tons
MSW	Municipal Solid Waste
MW	Megawatt
NA	North American
N₂O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standard
NEI	National Emissions Inventory
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NGCT	Natural Gas Combustion Turbine
NH₃	Ammonia
NMHC	Non-methane Hydrocarbon
NO	Nitrogen Oxide
N₂O	Nitrous Oxide
NO₂	Nitrogen Dioxide

NO_x	Oxides of Nitrogen
PAFC	Phosphoric Acid Fuel Cell
PAN	Peroxyacetyl nitrate
PC	Pulverized Coal
PEMFC	Proton Exchange Membrane Fuel Cell
PFBC	Pressurized Fluidized Bed Combustion
PK	Peaking
PM	Particulate Matter
PM_{2.5}	Fine Particulate Matter
PV	Photo Voltaic
SC	Supercritical
SCR	Selective Catalytic Reduction
SF₆	Sulfur Hexafluoride
SMR	Steam Methane Reformation
SO₂	Sulfur Dioxide
SOFC	Solid Oxide Fuel Cell
SO_x	Oxides of Sulfur
TES	Thermal Energy Storage
TPY	Tons Per Year
TSP	Total Suspended Particulate
USC	Ultra-supercritical
VOC	Volatile Organic Compound
WECC	Western Electricity Coordinating Council
WWTP	Waste Water Treatment Plant

coming decades [28]. This is particularly true for electricity generation - both the current and expected mix of U.S. generation include natural gas use at high levels (i.e., coal and natural gas currently account for 37% and 30% of U.S. power generation) [29]. The displacement of natural gas from domestic energy systems therefore represents a major undertaking and could require significant investment in more expensive alternatives. Furthermore, natural gas power generation can provide important energy services including the ability to provide grid-balancing services that can well complement the integration of intermittent renewable resources (including wind and solar) into regional electrical grids. Additionally, the existing natural gas system infrastructure can be used to store, transport, and distribute renewable gaseous fuels and could provide a long-term transition path from an entirely fossil to entirely renewable system. Thus, the role of natural gas moving forward in the greater context of GHG mitigation and AQ improvement is complex and multi-faceted requiring considerations of more than simple quantification and comparison of total emissions.

It is with this uncertainty that natural gas approaches a crossroads in terms of energy and the environment. Thus, there is a need for further understanding by what means natural gas generation and natural gas infrastructure can support short- to long-term environmental quality goals in terms of pathways forward from an economic and regulatory perspective. This work seeks to provide some clarity by evaluating the literature for natural gas electricity generation to gain insights into the emissions of GHG and criteria pollutants with implications for regional AQ. Additionally, technology transitions that could be applied to maximize GHG and AQ co-benefits are discussed in the context of pathways forward. [Section 2](#) of this work reviews emissions from conventional natural gas generation with a specific focus on comparison to coal generation methods. [Section 3](#) presents an overview of advanced natural gas conversion methods that can provide efficiency and emission benefits relative to conventional technologies. [Section 4](#) provides an overview of potential GHG and AQ impacts of additional low-carbon generation methods for comparison with natural gas. [Section 5](#) reviews and discusses potential for natural gas generation to support the integration and use of renewable resources as a means of maximizing AQ and GHG benefits. Finally, [Section 6](#) provides discussion and proposes an evolution of natural gas infrastructure to best attain sustainable

electricity provision while maximizing GHG and AQ co-benefits. It should be noted that the scope of this review is natural gas use for electricity generation and does not consider in-depth use in additional energy end-use sectors including transportation, industry, and the built environment.

2. Emissions from traditional natural gas generation

Current methods of natural gas generation generally comprise combustion with technologies commonly used including conventional boilers, steam turbines, simple-cycle gas turbines (NGCT) and combined cycle (NGCC) systems. Additionally, combustion to power a small turbine or reciprocating engine is often utilized, particularly in smaller, distributed-scale applications. NGCC plants are comprised of three main components, (1) a gas turbine (Brayton cycle that includes compressor, combustor and turbine), (2) a steam turbine (operating on the Rankine cycle), and (3) a heat recovery steam generator that integrates the two cycles together by generating steam from the upstream gas turbine exhaust [30]. At the central plant scale NGCC plants are capable of high fuel-to-electricity efficiency potentially in excess of 60% measured at lower heating value (LHV) and low criteria pollutant emissions when integrated with a selective catalytic reduction (SCR) emissions clean up system [31]. Simple-cycle gas turbines used in power plants are now available with efficiencies greater than 40% [32]. The higher efficiencies and reduced emissions of NGCC make them preferable to other generation types and it is likely NGCC plants will be the dominant technology for new capacity in the U.S. [33,34]. An additional capability of natural gas generation includes combined cooling heating and power (CCHP) with efficiency and economic improvements by capturing and using waste heat for useful work [35]. Gas turbines are highly effective for CCHP applications due to high exhaust temperatures which can generate process steam used for a variety of purposes (e.g., to meet heating or cooling loads for a large commercial building, used directly for industrial purposes). CCHP devices and impacts are discussed in Section 3.1.

A range of factors impact direct² emissions from natural gas generation including selected conversion technology, size, age, operating load and dynamics, presence or absence of pollutant controls, gas composition, and others. Reported emissions generally represent data collected during operation at design conditions (e.g., greater than 80% of rated capacity) [36]. However, this may not be wholly representative of real-world operation which is often dynamic in nature. Emission rates from turbines under reduced loads or during rapid load adjustment are typically higher due to lower efficiencies, less complete combustion, and off-design operation of air pollution control equipment [37]. Additionally, the generators most likely to respond to grid dynamics, such as those operating on the margin, are often simple cycle turbines with higher emissions and lower efficiencies [38]. Finally, the start-up and shut-down of power plants also usually entail periods of relative high emissions (of both GHG and pollutants) per unit of power generated [39].

Natural gas generation produces emissions of CO₂, methane, and nitrous oxide (N₂O), with CO₂ being the predominant direct emission. Life cycle air emissions through the point-of-generation for a 555 megawatt (MW) NGCC generation facility utilizing two parallel, advanced F-Class combustion turbines followed by heat recovery steam generators are shown in Table 1. The plant typifies a facility representative of future plant construction in the replacement of retired, less efficient facilities and/or to provide needed new-installed capacity [34]. State-of-the-art natural gas generation also may further reduce emissions from conventional technologies, e.g.,

Table 1

Life cycle air emissions for a NGCC plant with natural gas from domestic resources. Adapted from [49].

	Domestic NG production	NG Pipeline transport	NGCC plant	Total
Greenhouse Gas Emissions (g CO ₂ e/kWh)				
CO ₂	20.80	3.95	393.00	418.00
N ₂ O	0.20	0.00	0.00	0.18
CH ₄	47.70	19.20	0.01	66.90
SF ₆	0.01	0.00	0.01	0.01
GWP	68.80	23.20	393.00	484.73
Pollutant emissions (g/kWh)				
NO _x	0.4820	0.0008	0.0305	0.5130
SO ₂	0.0059	0.0003	0.0012	0.0074
CO	0.0435	0.0006	0.0031	0.0472
VOC	0.3810	1.59E-05	3.72E-05	0.3810
PM	0.0010	0.0001	0.0004	0.0015

358 g CO₂ equivalents per kilowatt hour (CO₂e /kWh) as reported in [40] for a life cycle 517 MW NGCC base load facility with a net HHV efficiency of 50.2%. Generally, life cycle emissions (i.e., including all stages of gas production and distribution) have been reported for natural gas combustion turbines from 487 to 987 gCO₂e/kWh [41,42] and 306 to 681 for combined cycle plants [31,36,40–48] (Table 2).

Direct pollutant emissions from natural gas plants include NO_x, CO, VOC, PM, SO₂ and potentially hazardous air pollutants (HAP) including formaldehyde [52,53]. Generally, emissions of SO₂ and PM are low, while emissions of NO_x and CO require emissions control including combustion design and SCR [36]. Average NO_x emission rates from an existing fleet of NGCC plants measured under EPA reporting requirements were 0.0635 g/kWh, equivalent to a reduction of 92.7% from average U.S. coal-, oil-, and natural gas-fired plants [48]. Similar to GHG impacts, it is estimated that growth in the fraction of domestic gas generation in place of coal from 1995–2012 reduced CO₂ (23%), NO_x (40%), and SO₂ (44%) emissions from U.S. fossil-fuel power plants [33]. With SCR and/or lean pre-mixed combustion emissions of NO_x for large gas turbines are often well below 10 parts per million (ppm) as seen for the plant in Table 1 [32]. Emissions from an advanced 560 MW NGCC plant at a capacity factor of 85% with best available control technology (BACT) achieved requirements from the 2006 New Source Performance Standards (i.e., 2.5 ppm volumetric dry referenced to 15% O₂) via a combination of dry low-NO_x burner combustion and SCR systems with actual emissions measured at 0.0139 g NO_x/kWh [36]. Emissions of additional pollutants including SO₂, PM, and mercury were negligible. Demonstrating variation with specific plant characteristics and others, direct pollutant emissions from the 555 MW NGCC plant in [49] were reported at 0.0305 g NO_x/kWh.

These values generally represent a reduction from coal (i.e., from current and advanced coal plants in [40]) but are higher than other alternative technologies including renewables, nuclear power, and

Table 2

Reported life cycle greenhouse gas for various generation technologies operating on natural gas. NG CT: Natural Gas Combustion Turbine. NG CC: Natural Gas Combined Cycle. LNG CT: Liquefied Natural Gas Combustion Turbine. LNG CC: Liquefied Natural Gas Combined Cycle.

Technology	Life Cycle GHG [gCO ₂ e/kWh]	References
NG CT	487 to 987	[41,42]
NG CC	306 to 681	[31,36,40–48]
LNG CT	607 to 651	[50,51]
LNG CC	428 to 523	[42,50,51]

² An important distinction should be made between direct emissions, which are released from the point-of-generation, and life cycle emissions which occur throughout the various stages of natural gas production and distribution

Table 3

National average GHG and criteria air pollutant emission factors (g/kWh) for U.S. generation in 2010. Adapted from Reference [59]. IGCC: Integrated gasification combined cycle, IGCC: Integrated Gasification Combined Cycle, CC: Combined Cycle, ICE: Internal combustion engine.

Technology	CO ₂ Emissions [gCO ₂ e/kWh]	NO _x [g/kWh]	SO _x [g/kWh]	PM _{2.5} [g/kWh]
Coal Steam Turbine	997	1.14	3.19	0.19
Coal IGCC	980	0.12	0.04	0.72
NG CC	441	0.12	0.004	0.0009
NG Gas Turbine	652	0.35	0.02	0.04
NG Steam Turbine	638	0.86	0.17	0.04
NG ICE	619	3.08	0.006	0.47

Table 4

Direct Emissions for advanced coal power plants. Adapted from References [60,61,64]. A-USC: Advanced ultra-supercritical, CFBC: Circulating Fluidized Bed Combustion, IGCC: Integrated gasification combined cycle, IGFC: Integrated gasification fuel cell, PC: Pulverized Coal.

Technology	CO ₂ Emissions [gCO ₂ e/kWh]	NO _x [g/kWh]	SO _x [g/kWh]	PM _{2.5} [g/kWh]
Sub-critical	850–1000	0.5–1.5	0.5–0.7	0.1
Ultra-supercritical PC	740–834	<0.16–0.42	<0.06–0.42	<0.042
CFBC	880–900	<0.84	<0.16–0.42	<0.21
A-USC PC	670–767	<0.16–0.42	<0.06–0.42	<0.042
IGCC	670–846	0.1–0.13	0.01–0.06	<0.0042
IGFC	500–550	<0.13	<0.06	<0.0042
Oxy-combustion	720	—	—	—

the deployment of CCS, e.g., see [10,54–56]. Solely considering direct emissions, natural gas represents an option for GHG emissions mitigation and potential AQ improvements if replacing coal plant operation, particularly in the near-term, and it is this ability that has led to the proposition as a bridge fuel to future, cleaner technologies [57,58]. The carbon content for natural gas is roughly half that of coal per unit of energy, and gas-fired technologies generally have higher efficiencies and reduced emissions of major pollutant and HAP species, including mercury, NO_x, CO, SO₂ and PM [34,40,57]. Table 3 contains the national average GHG and pollutant emission factors for 2010 U.S. generation. Current coal integrated gasification combined cycle (IGCC) facilities emit NO_x at similar levels to NGCC and reduced levels from simple cycle natural gas turbines, but represent only 0.1% of coal combustion technologies relative to steam turbines. Similarly, averaging of historical emissions data on existing U.S. power plants shows that coal-fired plants emit approximately double the CO₂ of both NGCT and NGCC plants [33]. This trend is also evident in emission projection data as transitions to natural gas from higher GHG intensity fossil fuels contribute to energy related CO₂ emissions slightly declining in total from 2005 to 2040 [29].

Advanced coal generation strategies could potentially improve efficiencies and reduce emissions from current coal technologies, including ultra- and advanced ultra-supercritical technologies (A-USC), fluidized bed combustion (FBC), oxy-combustion, and various IGCC configurations [60–62]. Advanced coal concepts also include CCS to reduce CO₂ emissions, however CCS is considered and discussed in Section 4.3 as CCS is also applicable to natural gas

generation. The use of fuel cells to convert syngas to electricity (IGFC) can further reduce emissions and may represent the lowest emitting coal pathway if CCS is also integrated (Table 4). Fig. 1 demonstrates a simple diagram of an IGFC strategy for coal conversion, although other fuels including biomass are also suitable. These strategies can reduce GHG and pollutant emissions significantly from current coal generation methods, e.g., sub- and supercritical pulverized coal plants (Table 4). IGCC can potentially represent the cleanest pathway for coal generation [63]. However, emission rates of GHG and pollutants are higher for technologies requiring significant advancement prior to commercialization compared to NGCC plants already commercially deployed and economically competitive, e.g., the plant discussed in [49]. Advancements may also be made with regards to natural gas technologies following similar trajectories to those for coal, and it is likely that natural gas will continue to provide emission reductions and AQ improvements if displacing coal generation in future years.

Impacts must also be considered within the context of regional variation in the composition of generator networks that comprise regional electrical grids, as this is a direct determinant of overall emissions and AQ impacts. Emission rates of CO₂e, NO_x, and SO₂ for current electricity generation types are shown in Table 5 for the U.S. average and a sampling of regional grids, including the Western Electricity Coordinating Council California (WECC CA) region, Electric Reliability Council of Texas (ERCOT), and ReliabilityFirst Corporation West (RFC West) including most of Indiana and Ohio and parts of several other states including Pennsylvania, West Virginia, Virginia, and Kentucky. When compared to the direct emission from the NGCC plant described in [49], deploying NGCC generation would

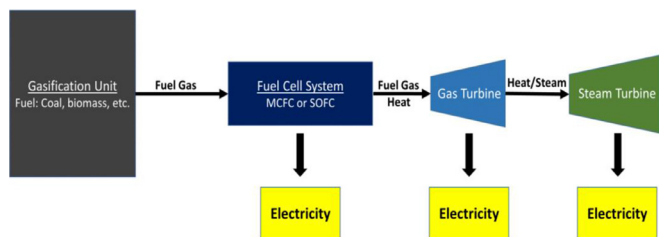


Fig. 1. Simple diagram of an integrated gasification fuel cell (IGFC) concept for coal power generation. Adapted from [60]. SOFC: Solid Oxide Fuel Cell, MCFC: Molten Carbonate Fuel Cell.

Table 5

Emission rates in grams/kWh of electricity generation for the U.S. average and regional electrical grids. Data from eGRID 2012 [66]. *Direct plant emissions from 555 MW NGCC plant from [49].

Region/Source	Prominent State(s)	CO ₂ e	NO _x	SO ₂
U.S. Average	All	517	0.43	0.86
WECC CA	California	296	0.15	0.09
ERCOT	Texas	520	0.28	0.87
RFC West	Indiana, Ohio, etc.	628	0.55	1.54
NGCC*	—	393	0.03	.003

Table 6
Potential methane emission from the natural gas system. From U.S. EPA [90].

Sector	Potential Emissions [kilotons]	Key Sources
Production	4710	Gathering and boosting stations, pneumatic devices, pipeline leaks, well pad equipment, liquid unloadings
Processing	445	Compressors, plant fugitives, flares, dehydrators, pneumatic devices, blowdowns, venting
Transmission & Storage	1688	Compressors (exhaust and fugitive), pipeline venting and leaks, pneumatic devices,
Local Distribution	480	Pipeline leaks, customer meters, upset events, routine maintenance

achieve GHG reductions in all regions except WECC CA (largely due to a lack of coal and higher levels of renewable generation in this region). Additionally, emissions of NO_x and SO_2 are significantly lower for NGCC than the average for all regions including WECC CA. Thus, deploying a NGCC plant could potentially achieve GHG reductions in most regions of the U.S., but not in California, while also reducing pollutant emissions from current generation. Pollutant emission reductions would be larger for generation in the RFC West and ERCOT territory, with lesser benefits in California. Therefore, the use of gas generation for AQ and GHG mitigation is more favorable in certain U.S. regions than others, highlighting both the regional nature of electricity generation and AQ concerns. It should also be noted that average emissions do not necessarily represent generation impacted by natural gas plants, and marginal emissions are a more appropriate method of comparing regional grid emissions [65].

The common understanding that natural gas represents an opportunity for AQ and GHG co-benefits relative to coal is confirmed by the literature. In recent years coal and natural gas have experienced divergent trends in response to low natural gas prices [67] and the development of environmental regulations targeting the emissions of coal power plants and it is expected that natural gas will surpass coal as the dominant power sector fuel by 2035 [29]. Indeed, this displacement has helped contribute to reductions in pollutant and GHG emissions from the U.S. electricity sector in recent years [68]. Replacing coal- with gas-fired power generation yields reductions in direct pollutant and HAP emissions potentially translating to improvements in ambient primary and secondary pollutant concentrations, including ozone and PM [34]. Atmospheric modeling has shown that reductions in SO_2 from natural gas displacement of coal can reduce regional PM concentrations via PM sulfate mechanisms [69]. Reductions of HAP including mercury, acid gases, metals and metalloids, dioxins and furans will provide immediate health benefits to populations impacted by coal power plant emissions [68]. Also, improving the performance of emission control technology on current coal plants can provide benefits to ground-level pollution, including ozone and PM [70].

2.1. Emissions from natural gas life cycle stages

Emissions from additional life cycle stages associated with natural gas production and distribution must be accounted for to completely assess GHG and AQ impacts of gas generation. The infrastructure associated with the production, storage, and distribution of natural gas to end-users is an extensive and complex system. Using terminology from [53,71], the life cycle stages of natural gas include pre-production, gas production, transmission, distribution and storage, and well production end-of-life, with all stages generating emissions of GHG and pollutants [72]. Pre-production includes all aspects of site exploration, clearing, and road construction, drilling, hydraulic fracturing, and well completion [53]. The production stage includes the recovery, compression, and processing of gas to ensure pipeline quality standards are met, with emissions occurring from compressors, pumps, heaters, leaks, venting and flare activity, and other maintenance processes [73]. The transmission, storage, and distribution of natural gas include the translocation of processed gas to end-users including long distance pipelines and local distribution networks.

Direct emissions (also termed fugitive emissions or leakage) occurring throughout the natural gas supply chain are a key determinant of climate impacts for power generation as the primary constituent of natural gas is methane, a potent climate forcing gas³ [74–76]. A variety of techniques and methods have been used to characterize upstream methane emissions; including engineering analyses and quantification via both bottoms-up and top-down approaches [77–80]. However, the current understanding of direct methane emissions contains a substantial degree of uncertainty which complicates a thorough understanding of technology impact when operating on natural gas [72,77].

Available life cycle studies generally demonstrate an improvement from coal even if higher GHG intensity liquefied natural gas (LNG) is utilized as a fuel (Table 2). However, it has been suggested that life cycle (i.e., well construction through end use) methane leakage estimates are higher than previously thought [81]. Natural gas electricity generation may reduce GHG emissions on all time scales relative to coal if methane leakage rates do not exceed 3.2% of total system production [72]. Current and projected expansion in U.S. natural gas supplies from non-traditional reserves, including those associated with hydraulic fracturing, could also impact the climate benefit potential of natural gas. Unconventional gas resources (e.g., shale gas) have been estimated to have leakage rates potentially 30–50% higher than conventional gas with GHG emissions that could exceed those from coal over a 20-year interval [22]. Some estimates have reported that generation even from conventional gas may not reduce GHG emissions relative to coal in the same period [82]. However, others have questioned these conclusions citing an overestimation of leakage rates, the short-period of global warming potential (20-years) used for the assessment of methane impacts, and the lack of accounting for additional benefits during conversion [83]. Life cycle GHG emissions from the production of Marcellus shale natural gas reported a 3% increase from traditional gas and 20–50% decrease from coal depending on plant efficiencies and natural gas emissions variability [84]. Moreover, it has been reported that unconventional gas may have a lower GHG footprint per megajoule (MJ) than conventional gas [85]. A summary of available literature estimates that emissions from the natural gas supply chain total 76.2 g $\text{CO}_2\text{eq/kWh}$ which, if included, still results in less net emissions than coal when added to direct emission estimates for most natural gas pathways [86]. A comprehensive review of the literature concerning estimation of the GHG footprint of the domestic natural gas production and distribution system, including traditional and unconventional reserves, is beyond the scope of this work and can be found in [75, 85–87].

Shown in Table 6, quantitatively domestic methane emissions are dominated by sources in the production and transmission and storage sectors, with key sources including gathering and boosting stations, pneumatic device vents, compressors (both fugitive and exhaust), and pipeline venting and leaks. Methane is the primary GHG of concern for all life cycle stages of natural gas infrastructure except generation/end-use, where CO_2 is the most important (Table 7). Pneumatic controllers are an important source of direct methane emissions and are present in nearly all sectors of the

³ It is of interest to note that this characteristic of the fuel itself being an important GHG is unique among common fossil fuels

Table 7

Associated emissions and AQ concerns from life cycle stages for natural gas power generation. Adapted from [53,91]. **Note that impacts of highest concern are in bold**.

Life Cycle Stage	GHG	Pollutant Emissions	Potential AQ Concerns
Preproduction	Methane	NO_x, VOC , PM _{2.5} , SO ₂ , HAPs	Regional ozone and PM, localized HAP
Production	Methane	NO_x, VOC , PM _{2.5} , SO ₂ , HAPs	Regional ozone and PM, localized HAP
Transmission, Distribution, and Storage	Methane	NO_x, VOC , PM _{2.5}	Regional ozone if emissions in urban areas
Use/Generation	Methane, CO ₂	NO_x, CO , SO ₂ , PM, HAPs	Regional ozone and PM
Well Production End-of-Life	Methane	-----	-----

natural gas system, including production [88]. For the transmission, storage, and distribution of natural gas, the predominant GHG of concern is methane released from numerous sources including faulty piping and valves, pneumatic controllers, and unburned methane in the exhaust of powered compressor stations [89]. Similarly, methane emissions associated with gas leakage from plugged or abandoned wells, in-well production and/or in-well end-of-life stages are a concern.

Similarly, pollutant emissions from life cycle stages of natural gas recovery and production can lessen the expected AQ benefits of natural gas replacement of coal and impact human health [91]. Table 7 summarizes emissions of concern and potential AQ impacts from different life cycle stages. Emissions from pre-production include CO₂, PM_{2.5}, NO_x, and VOC from mobile source on- and off-road diesel engines and PM₁₀ from road dust and tire/brake wear. Emissions from drilling and hydraulic fracturing including engines operating on diesel and/or natural gas have been shown to be a significant [92]. Releases of CO₂, methane, VOC, NO_x, SO₂, hydrogen sulfide and various HAP occur during drilling and well completion processes [53,91]. For wells undergoing hydraulic fracturing emissions of methane, VOC, and HAP are possible from flowback, i.e., the return of fluids and solids to the surface with produced water and gas [93]. Production sites and compressor stations have been associated with high levels of VOC, NO_x, PM_{2.5}, and SO_x [53,91]. A key source of methane, VOC, and HAP emissions is liquid unloading processes [78,94] including fugitive emissions from tanks [93]. Additional emissions (e.g., NO_x, CO₂, CO) accrue from pumping stations (typically gas turbine powered compressors), let-down stations (which burn natural gas to overcome Joule-Thomson cooling), and other natural gas-fired equipment in the transmission, storage and distribution system [95].

Understanding AQ impacts from gas production from both conventional and unconventional resources is challenging as emissions from these processes vary in composition, magnitude, and duration, and depend upon numerous factors including raw gas composition, extraction technique, and handling approach [93]. Due to numerous factors including the diffuse nature of some sources, different raw gas compositions, and variation in emissions controls, the AQ impacts from production have been reported as very significant, minor, or none [53]. The pre-production phase can last weeks to months, while production can persist years to decades, requiring that the impacts must also be considered temporally. Development of new well sites can produce harmful effects locally while avoiding major regional impacts. The extraction and production of gas has been linked with notable emissions of ozone precursor emissions including NO_x and VOC [91,96], the novel existence of ground-level ozone concentrations in excess of NAAQs [22], and detrimental

health effects from exposure to associated air emissions [97]. In particular, areas of gas production in Texas, Utah, Wyoming, and Colorado have been associated with ozone and other AQ issues occurring from the release of NO_x, methane, CO₂, and other VOC from processing plants and diesel truck exhaust [98–102]. In counties supporting high levels of gas production total NO_x emissions can be 20–40 times higher than permitted levels for a single, minor source [91]. Emissions from compressor engines and flaring have been reported to significantly increase (i.e., 6–10 ppb) ambient ozone downwind of a hypothetical gas processing facility [103]. Thus, a comprehensive view of AQ effects from transitions to natural gas must also account for potential worsening of AQ in regions supporting gas development, in addition to improvements from sites of power generation. Considering this, a regional assessment of increased natural gas use in the Texas power sector accounting for perturbations at both the generator and production level has reported net reductions in NO_x and SO₂ and net increases in VOC emissions; translating to modest reductions in ozone (0.2 to 0.7 ppb) and PM_{2.5} (0.1 to 0.7 µg/m³) [69]. The study concluded that direct plant emission reductions were capable of offsetting emission increases at gas production sites. This again should be evaluated in the context of coal generation offsets, which for the Texas grid, for example, are significant. Similar impacts may not be observed depending upon the composition of a region's generator mix, which highlights again the regional nature of AQ impacts.

It should also be considered that the importation of natural gas may also have different environmental impacts than those from domestic reserves. While the current availability of domestic gas averts the need for significant importation (i.e., U.S. natural gas net imports fell to a record low in 2016 [104]), future demands could require the U.S. to do so. In fact, the U.S. is likely to become a net exporter of LNG in coming years [105]. Imported gas has a higher emission footprint than domestically produced gas due to the additional life cycle stages required including liquefaction, transport, and regasification [49]. Often transport is accomplished via ocean transport on LNG tanker ships which are high emitting if operating on heavy fuel oils [106]. Table 8 demonstrates the emission burdens associated with the acquisition and transport of domestic and imported NG. Imported natural gas is assumed to be foreign offshore gas extraction, followed by liquefaction, ocean transport via LNG tanker, regasification and pipeline transport to the NGCC facility. Imported gas is associated with higher emissions of GHG due to emissions occurring during liquefaction, transport, and regasification. Contrastingly, emissions of air pollutants including NO_x and SO₂ vary with some domestic pathways having higher associated emissions. Thus, changes in the origin of natural gas supply may shift impacts on AQ and GHG.

Table 8

Emissions from raw material extraction and transport of NG from domestic and imported sources in g/kg delivered. Adapted from Reference [49].

Emission	Conventional Onshore	Conventional Offshore	Barnett Shale	Tight Gas	Imported Offshore
CO₂e	733	345	702	696	930
NO_x	0.0395	0.00122	0.0300	0.0393	0.00156
SO₂	0.000275	0.0000602	0.000129	0.00118	0.000214

The potential implications of direct methane emissions from the natural gas system further reduce optimism for from a climate mitigation perspective. These concerns are heightened due to current uncertainty regarding methane emissions from the natural gas system [72,107]. Indeed, the rapid rise in production of gas from unconventional reserves in some ways has exceeded the ability of researchers to understand and predict potential impacts [53]. This has led to significant variations and uncertainty in the literature, e. g., life cycle GHG emission estimates that conflict significantly in magnitude [22,82,83,85,108–110]. If leakage is underreported and/or increased, direct emissions of methane could even reduce the expected GHG reductions reported here. This trend has been demonstrated in recent studies indicating that upstream methane emissions may offset the carbon mitigation potential of natural gas relative to other fossil fuels [76,111]. To address this, significant research efforts are underway in the U.S. including a comprehensive initiative involving 16 independent studies aimed at quantifying and identifying emissions of methane across all areas of the oil and gas supply chain [112].

Conversely, if significant progress is made in controlling and reducing system-wide methane emissions in the U.S. the carbon intensity of gas generation may improve. In recent years the U.S. EPA has taken several regulatory actions aimed at reducing methane emissions from the oil and gas industry including New Source Performance Standards from new, reconstructed, and modified sources [113]. Additionally, the Natural Gas STAR Methane Challenge Program was launched to encourage U.S. oil and gas companies to make more specific and transparent commitments to reducing methane emissions [114]. Historical evaluation of EPA programs and policies to reduce methane emissions demonstrated successful abatement [115].

However, the potential for worsening of ozone and HAP levels at sites of gas recovery and production should also be considered alongside the direct emission impacts of natural gas generation. Unconventional gas recovery also carries other environmental risks including the high consumption [98] and contamination of fresh water resources [116,117] including drinking water supplies [118] with the potential for harmful human health impacts [119]. Therefore technology lock-in associated with the construction of new natural gas generation technologies, including advanced NGCC, should be considered with importance in GHG and AQ mitigation planning. And the evolution of the natural gas system that should be promoted by policy must include measures to prevent leakage in upstream operations, in transmission and distributions systems, and in customer-side of the meter and end-use applications. The evolution could also include substitution of lower global warming potential (GWP) fuel to lower the impacts of any remaining leakage.

3. Emission reductions from advanced conversion technologies

Emissions from natural gas generation can be reduced further via the use of advanced conversion devices. The preceding discussion was primarily focused on existing technologies used in large,

centralized power plants. However, conversion can be accomplished with devices that have higher efficiencies and the potential for very low emissions – including advances in NGCC technologies, fuel cells, micro-turbines, and hybrid fuel cell/heat engine plants [120]. Such methods can provide pathways for natural gas generation to fulfill valuable energy services while minimizing emissions – including providing efficient and low-impact generation that can facilitate the complementary balancing of renewable resources, defer investment in electrical infrastructure, and/or provide ancillary services to the grid. Additionally, these devices can operate on natural gas in the near- to mid-term and renewable fuels and blends in the mid- to long-term providing a link from fossil to renewable fuel systems. For example, fuel cells can operate on conventional natural gas, fossil and renewable hydrogen, and biogas with a flexibility that allows for important opportunities to reduce emissions.

An additional key characteristic for advanced systems includes the ability to provide CCHP as this attribute displaces the fuel and emissions that would otherwise be associated with (1) boilers and furnaces (in the case of using the thermal energy directly as heat), and (2) the displaced electricity to drive chillers (in the case of using the thermal energy for cooling) [121]. The resultant effect is to reduce CO₂ emissions, criteria pollutant emissions, and the demand on fuel reserves. Potential CCHP devices include fuel cells and fuel cell-heat engine hybrid systems, gas turbines including microturbines, steam turbines, and reciprocating engines. Cost and performance parameters for CCHP devices are provided in Table 9. A detailed overview of CCHP technologies can be found in [35]. Changes can also be made to the paradigm of natural gas electricity generation, transmission, and distribution with potential for emissions and AQ benefits. A primary example includes transitions from the centralized model of power generation involving large power plants located far from population centers requiring electricity transmission over long distances to distributed generation (DG) involving electricity production at or near the point-of-use [122]. In addition to avoiding losses during transmissions, DG benefits include potentially lower costs, reduced emissions, higher power quality, reliability, and security [123]. DG also enhances the ability for CCHP inclusion in system design, e.g., centralized NGCC can also provide CCHP but are often located far from population centers or other sites of heating or cooling demand.

3.1. Advanced conversion technologies

Steam turbines are typically matched to solid fuel boilers, industrial waste heat, or integrated with a gas turbine as a bottoming cycle to create combined cycles. Typical capacities for steam turbines range from 50 kW to several hundred MW in large centralized power plants. Steam turbine benefits include high fuel flexibility, high reliability and equipment lifetime, and flexibility of design. Reciprocating engines represent a mature and commercially available heat engine technology that make up over half of existing CCHP systems in the U.S. [35]. Reciprocating engines can operate with either spark

Table 9

Cost and performance parameters for self-generation CCHP Devices. Data adapted from [35,127,128]. LPG: Liquefied Petroleum Gas.

	Fuel Cell & Hybrid Systems	Recip. Engine	Steam Turbine	Gas Turbine	Microturbine
Electric Efficiency (HHV)	30–65%	27–41%	5–40%	24–36%	22–28%
Net CCHP Efficiency (HHV)	55–90%	77–80%	Approx. 80%	66–71%	63–70%
Typical Capacity (MW)	0.2–2.8	0.005–10	0.5–hundreds	0.5–300	0.08–1
Power Density (kW/m²)	5–20	35–50	> 100	20–500	5–70
Part-load Potential	Good	OK	OK	Poor	OK
CCHP Installed Cost (\$/kW)	5000–6500	1500–2900	670–1100	1200–3300	2500–4300
Non-fuel O&M Cost (\$/kWh)	0.032–0.038	0.009–0.025	0.006–0.01	0.009–0.013	0.009–0.013
Start-up Period	15 min – 3 hrs – 2 days (by type)	10 seconds – 15 min	1 h – 1 day	2 min – 1 hr	60 sec
Potential Fuels	NG, H ₂ , biogas, propane, methanol	NG, biogas, LPG, sour gas, industrial waste gas,	All	NG, biogas, synthetic gas	NG, biogas, sour gas, liquid fuels

Table 10

Typical operating characteristics and applications of fuel cell types. *Refers to direct use of fuel. External reformer allows all to operate on natural gas. **Operating on natural gas.

Fuel Cell Type	Avg. Size [kW]	Potential Fuels*	Operating Temp [°F]	Electrical Efficiency [%]**	Generation
Solid Oxide (SOFC)	700–1000	NG, H ₂ , Biogas	~1800	60%	Utility/central DG, CCHP
Molten Carbonate (MCFC)	600–700	NG, H ₂ , Biogas, Syngas	~1200	50%	Utility/central DG, CCHP
Alkaline (AFC)	90–100	H ₂	225–475	60%	Military/space
Proton Exchange Membrane (PEMFC)	80	H ₂	175–200	30–40%	DG/backup
Phosphoric Acid (PAFC)	150–250	NG, H ₂ , Biogas	350–400	40%	Utility/DG CCHP

ignition or compression ignition and can range from very small (0.005 MW) to large (80 MW) systems, although typical CCHP systems sizes range from 0.005 – 10 MW. Benefits of reciprocating engines include low investment and operating cost, high flexibility, reliability and availability, high part-load efficiencies, load following capabilities, and fast start-up times. Drawbacks of reciprocating engines include the need for regular service due to moving parts, noisy operation, and elevated emissions of criteria pollutants and GHGs. Gas turbines have been used for stationary power generation for many decades and range in size from 500 kW to hundreds of MW. Typically, for CCHP applications, the most economic size range is 5-MW to the hundreds of MW-scale [35]. Gas turbines have lower emissions than other common fossil combustion heat engines but often still require clean-up or emissions control strategies including lean pre-mixed combustion and/or SCR to meet permitting requirements for continuous operation. Typically gas turbines used as CCHP are best suited for processes with a need for high temperatures (i. e., /nbw> steam production) [124]. Microturbines are small (typically 60–1000 kilowatt (kW)) gas turbine power plants that can be combined with a bottoming steam turbine cycle or operated as a stand-alone Brayton cycle. Microturbines and offer the benefits of simple design, compact size, low vibration and noise, and no required cooling [35]. Downsides of microturbines include high costs, low flexibility, and low electrical efficiencies, particularly at part load [124]. Typically, relative to NGCC plants, microturbine systems operating on natural gas must be integrated with CCHP to achieve reductions in GHG and must be integrated with SCR to achieve very low criteria pollutant emissions [35,125,126].

Fuel cells represent an advanced conversion technology with the potential to allow natural gas to be used in energy systems with very low emissions of GHG and pollutants. Fuel cell systems can operate on natural gas both directly and indirectly as natural gas can be converted to hydrogen through steam methane reformation (SMR). Fuel cells differ fundamentally from combustion in that they convert fuel chemical energy directly to electricity and heat by electrochemical reactions that are similar in concept to battery electrochemical reactions. An overview of fuel cell types and characteristics is provided in Table 10. Fuel cell systems have been produced using various materials sets (e.g., solid metal oxides (SOFC), molten carbonates (MCFC), phosphoric acid (PAFC), and proton exchange membranes (PEMFC)) [129] with high electrical efficiencies (up to > 60%) [130,131] and very low pollutant emissions operating on natural gas – even at the distributed scale [130,132]. Fuel cells are applicable for CCHP applications and have flexibility with regards to fuel, size, siting, and application choices [133]. This flexibility allows fuel cell systems to operate on a range of gaseous fuels, including hydrogen, natural gas directly, renewable fuels such as biogas and renewable hydrogen [134], or syngas produced from coal in tandem with CCS [135]. This flexibility allows for mixtures of fuels to be used with the particular benefit of facilitating biogas supplementation of natural gas (or vice versa) and the transition from natural gas to renewable gaseous fuels of various types.

The one step of transforming chemical to electrical energy, as compared to the multi-step process used by combustion devices of chemical to thermal to mechanical to electrical, typically results in high electrical efficiencies for fuel cells via avoided losses at each

conversion step. Fuel cell systems have demonstrated electrical efficiencies from 30% to levels exceeding 60% even in the single digit kW size class range [130,131]. This is substantially higher than electrical efficiencies that can be attained by heat engines at the DG scale as seen in Table 9. For example, reciprocating engines range from 27–41%, steam turbines from 5–40%, gas turbines from 24–36%, and microturbines from 22–28% [35]. As the amount of CO₂ generated per kWh of electricity produced is inversely proportional to the electrical efficiency, fuel cells emit less CO₂ per kWh of electricity produced than other electricity generating technologies using the same fuel. The inclusion of CCHP can increase all DG technology efficiencies substantially, to achieve 55–80% [35] and, with a judicious design, exceeding even 90% (mixed heat and electrical efficiency) [4]. Furthermore, CO₂ can be reasonably recovered from exhaust, particularly if the anode exhaust is not after-burned with the cathode exhaust, allowing for a further reduction in GHG emissions. This could also allow fuel cells to be incorporated with natural gas turbine cycles to produce high efficiency, low carbon power [136].

An additional distinction of fuel cell systems is the ability to provide hydrogen fuel as an output when operating on hydrocarbon fuels. This allows fuel cells to operate as tri-generation systems producing electricity, heat, and hydrogen [137]. Incorporating hydrogen production further increases the energy efficiency of the system and provides additional energy benefits – including the potential production of fuel for zero-emission hydrogen fuel cell electric vehicles. An important pathway for GHG and AQ co-benefits includes the operation of tri-generation fuel cell systems on biogas as this allows for a means of coupling very low or even net negative emission strategies in the power generation sector to the transportation sector [138].

Hybrid fuel cell-heat engine plants integrate a high temperature fuel cell (SOFC or MCFC) with a heat engine (e.g., gas turbine, reciprocating engine) to achieve even higher efficiency than a fuel cell alone (converting fuel cell heat to useful work) [139]. A basic schematic is provided in Fig. 2 for a hybrid fuel cell gas-turbine system. By utilizing energy synergies between the fuel cell and heat engine (e.g., fuel cell waste heat is turned into useful electrical work and compression power, and higher pressure operation increases fuel cell electricity production efficiency) enhanced performance is achieved. These emerging power plants are being developed by several manufacturers and have been shown to achieve very high electrical efficiencies [140–142] with ultra-low emissions even at

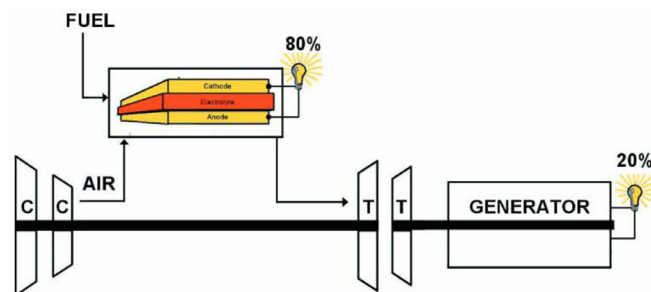


Fig. 2. Basic design concept of a gas turbine fuel cell hybrid power plant. Reprinted from [140] with permission of Elsevier.

distributed power sizes [140], and with dynamic dispatch characteristics [141,143].

However, fuel cell technologies face challenges for complete commercialization. High initial investment and installation costs must be reduced in order for fuel cells to compete with strong market competition from other CCHP technologies [144]. Specifically, the cost of fuel cell systems and components must be reduced [145]. Fundamental improvements are also needed to address reliability, durability, and fuel supply concerns to effectively permit expanded use of fuel cells [146]. High temperature fuel cells, including many of those suitable for the services discussed here, are limited by materials requirements, mechanical issues, reliability concerns, and technical issues such as thermal expansion matching [131]. Low temperature fuel cells also face materials and durability concerns [147]. Therefore, while fuel cells offer a generation pathway for natural gas with high environmental benefits, progress is needed in techno-economic areas to facilitate wide-spread adoption.

3.2. Advanced conversion device emissions

Table 11 shows emissions for five commercially available turbine systems both with and without SCR and CO oxidation ranging from 3 to 45 MW that have been compiled from vendor data [32]. At the DG scale, gas turbine systems have the potential for emission reductions from coal generation with or without the addition of CCHP. Additionally, the use of CCHP achieves additional reductions in CO₂ via offset of natural gas boiler operation necessary to provide equivalent heat.

Due to the electrochemical reactions fuel cells can reduce criteria pollutants (compared to the high temperature combustion of fuel in air) and due to the high electrical efficiency of fuel cells (especially compared to heat engines in the DG size class and including CCHP) they can also reduce GHG emissions [132]. The primary electricity generation process of fuel cells does not mix fuel with air and keeps temperatures low resulting in criteria pollutant emissions that are extremely low and, if the fuel input is hydrogen, only water vapor is produced in the exhaust. If the fuel is natural gas or another hydrocarbon fuel, the fuel processing subsystem required to facilitate electrochemical reactions in high temperature fuel cells is the sole source of CO₂ that is emitted along with very low levels of criteria pollutants [35]. Fuel cell system operation on biogas results in near net zero emission of carbon and fuel cell operation on renewable hydrogen (e.g., produced through renewable electrolysis) results in zero emission of carbon. Emissions of CO₂ from high temperature fuel cells operating directly on natural gas are significantly lower

Table 11

Emissions from commercially available distributed-scale gas turbines with and without CCHP. Adapted from [32]. *Net CO₂ includes the offset of emissions required from boilers to provide the same amount of heat for cooling and heating.

System Emissions [g/kWh]					
	1	2	3	4	5
Uncontrolled					
NO _x	0.594	0.295	0.313	0.259	0.236
CO	0.726	0.299	0.318	0.263	0.240
NMHC	0.041	0.036	0.036	0.032	0.027
With SCR and CO oxidation					
NO _x	0.041	0.023	0.023	0.023	0.023
CO	0.050	0.023	0.023	0.023	0.023
NMHC	0.036	0.027	0.032	0.027	0.009
Emissions of CO ₂					
Generation CO ₂	756	626	662	544	503
Net CO ₂ with CCHP*	361	302	313	290	296

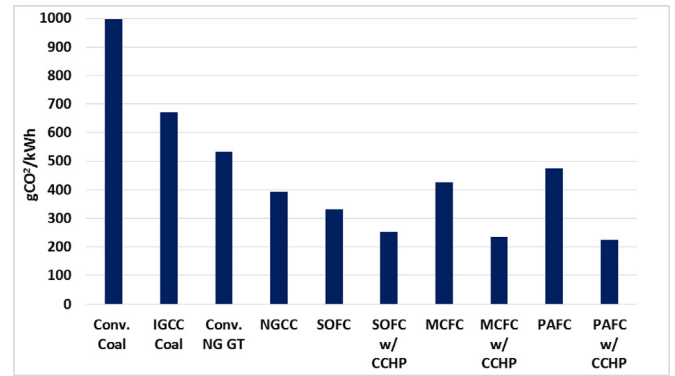


Fig. 3. CO₂ emissions from current and advanced coal and natural gas generation and various types of fuel cells with and without CCHP including Solid Oxide (SOFC), Molten Carbonate (MCFC), and Phosphoric Acid (PAFC). Conventional Coal and NG GT representative of 2010 U.S. generation technology averages [59], IGCC from [60], NGCC from [49], Fuel cells from Reference [35].

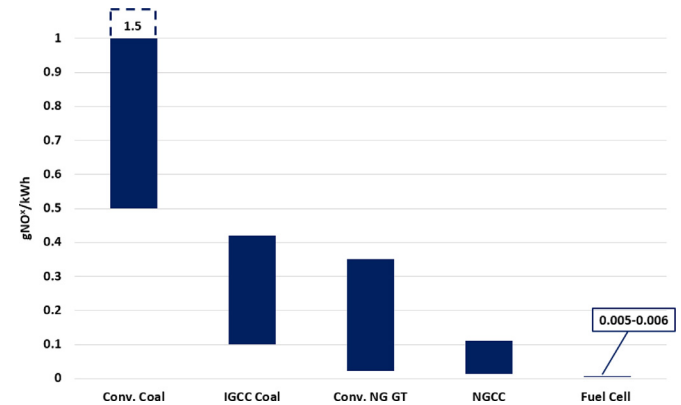


Fig. 4. NO_x emissions from current and advanced coal and natural gas generation and stationary fuel cells. Conventional Coal and NG GT representative of 2010 U.S. generation technology averages [59], IGCC from Reference [60], NGCC from [49], Fuel cells from [35].

than current and advanced coal technologies and current simple cycle natural gas turbines with or without the additional emission reductions from CCHP (Fig. 3). Relative to NGCC plants, SOFC can provide a reduction without the use of CCHP while PAFC and MCFC achieve a reduction from NGCC plants if CCHP is included. Advanced MCFC systems that include two fuel cell stacks in one system can achieve performance that is comparable to the SOFC performance shown in Fig. 3.⁴ Similarly, Fig. 4 displays the emissions of NO_x per kWh for both traditional and advanced heat engines using coal and natural gas, and stationary fuel cells operating on natural gas. Fuel cell conversion results in negligible emissions relative to other generation technologies including very low emissions of NO_x and CO, and negligible SO_x and PM [35,148]. Fuel cells achieve comparable or reduced CO₂ emissions compared to NGCC, and significantly reduced pollutant emissions, even at the distributed scale and without any after-treatment or other emissions control devices. If CO₂ capture is included GHG benefits from fuel cells would further increase.

Fig. 5 displays the CO₂ and NO_x emissions of CCHP technologies relative to the NGCC described in Reference [49]. With appropriately designed and operated systems, including emissions control technologies, CCHP devices can provide lower emission rates than current natural gas generation. Emissions of NO_x from fuel cells are significantly lower than all other options and require no emission

⁴ <http://www.fuelcellenergy.com/wp-content/uploads/2017/02/Product-Spec-Sure-Source-4000.pdf>.

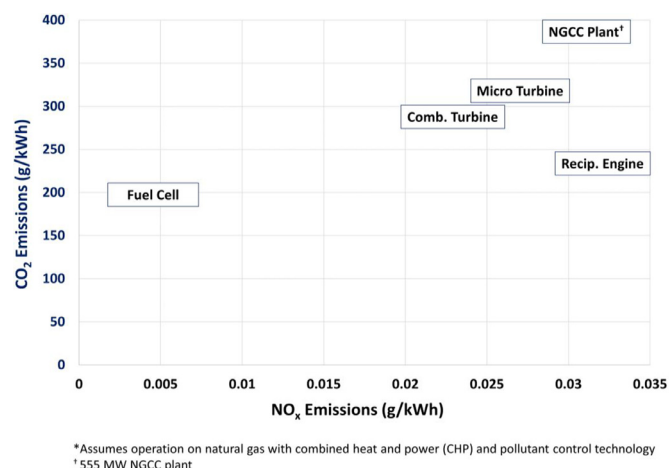


Fig. 5. Emissions of CO₂ and NO_x from self-generation CCHP devices relative to a current NGCC plant. Data for NGCC from Reference [49], Data for CCHP technologies from [35].

control device or strategy [35]. Gas turbine NO_x emissions have a large range but typical commercial systems generate 0.07 to 0.11 g/kWhr with lean premixed burners and the inclusion of SCR can further reduce emissions by 80 to 90% [35]. Microturbines operating on natural gas can achieve low NO_x emissions with lean premixed combustion at full load [35]. However, emissions commonly increase during operation at part load with implications for complementary generation or dynamic operation to support distributed loads. Reciprocating engines have the potential for high emissions, including NO_x, depending upon the type of engine used. Smaller scale engines utilizing rich burn combustion and catalytic after treatment can emit 0.027 g/kWh while larger lean burn systems may emit 0.36 g/kWhr in the absence of SCR. Steam turbine emissions depend directly on fuel choice with natural gas systems ranging significantly. With CCHP, combustion devices in DG applications could provide a GHG and AQ benefit via reduced emissions of both CO₂ and NO_x. Contrastingly, fuel cells with CCHP achieve significant reductions in emissions from all combustion devices without the need for post-conversion emission control strategies.

4. Low-carbon generation options

A diverse range of generation strategies exist that offer the potential for meeting future electricity demands in tandem with reduced emissions. Low-carbon generation technologies and fuels include renewable energy resources such as wind, solar, geothermal, ocean, hydropower, and biopower, nuclear energy, and fossil generation equipped with CCS. Methods to reduce electricity demand via improvements in the efficiency of power generation, transmission, distribution and end-use of electricity can result in less primary generation; lowering total fuel consumption and reducing emissions while meeting demands. Moreover, many studies have demonstrated that no one technology can provide the necessary reductions, and that a portfolio of low-carbon strategies will be required to meet climate goals [11,149,150]. The following section presents a brief review of the literature regarding the emissions and potential AQ impacts of additional low-carbon generation strategies including renewable pathways, nuclear, and CCS. While additional options exist, those selected for review herein are commonly considered for GHG mitigation, are currently at or near technological maturity levels portending significant potential expansion in capacity in the short- to mid-term, and are supported by a depth of available literature regarding impacts.

4.1. Renewable electricity

Technologies comprising renewable pathways are diverse and wide ranges are reported for different indicators including cost, performance, and environmental impact [151]. In general, renewable technologies have higher associated costs and lower power densities than current fossil fuels and many, including wind and solar, are inherently variable (diurnally, seasonally) requiring the co-deployment of complementary technologies to achieve acceptable systems-level dynamics (balancing of generation with fluctuations in load demand) [150,152,153]. Many locations with high resource potential are not adjacent to population centers, necessitating upgrade of existing and/or construction of new transmission infrastructure [154,155]. Due to these and other challenges, dramatically increasing the capacity of renewable power could require changes to current U.S. electrical grids to appropriately manage the intermittency, spatial distribution, and scalability of resources [16,54,156], e.g., requiring increased installed capacities, transmission infrastructure, and energy storage [11].

Hydropower is a mature technology that is associated with low emissions of GHG and criteria pollutants in operation [41]. Emissions from hydropower plant construction and lifetime are known to be much lower than those from fossil fuel power plants, although habitat impacts and direct GHG emissions from the degradation of biogenic carbon and reduced CO₂ uptake in hydropower reservoirs is important to consider [43]. For example, methane emissions from water storage reservoirs serving hydroelectric generators may result in a higher carbon footprint for hydropower than previously thought [157]. When reservoir emissions are included the global average emissions from hydropower are estimated to be 85 gCO₂/kWh and 3 gCH₄/kWh with a multiplicative uncertainty factor of 2 [158]. Constructing additional large-scale domestic hydropower plants is limited by high costs, siting limitations, habitat and other environmental impacts [159,160]. Therefore, typically small hydropower plants, often utilizing run-of-the-river approaches, are considered for renewable resource expansion in the U.S. with no harmful AQ impacts likely from such projects [161].

Power generation from solar energy commonly includes both photovoltaic (PV) and various forms of concentrated solar power (CSP). Estimates of the GHG intensity of solar PV electricity are reported in the range of 19–95 g CO₂eq/kWh for various thin film PVs (e.g., CdTe, a-Si, CIS) and 20–104 g CO₂eq/kWh for crystalline technologies (e.g., m-Si), although prospective advances in manufacturing could reduce emissions [43,50,162–172]. A critical review of the literature reported a range of 1–218 g CO₂eq/kWh with a mean value of 49.91 g CO₂eq/kWh [173]. Emissions vary with respect to characteristics of individual technologies (e.g., achieved efficiencies, required manufacturing processes) and regional deployment (e.g., insolation, meteorology) which impact total emissions and power output. Though life cycle emissions for PV are among the highest for renewable technologies the bulk of reported values are considerably lower than any coal or natural gas technology. Though less information is available for CSP, studies have reported a range of 12–284 g CO₂eq/kWh for various technologies with values in the upper range representing facilities incorporating natural gas-fired complementary generation [174–179]. Highlighting the impact of any gas generation to total emissions, studies reported a range of 30–149 g CO₂eq/kWh for parabolic trough technology when 3–25% natural gas back up was considered and 26–28 g CO₂eq/kWh for solar only processes [178,180]. Life cycle emissions for a 50 MW trough plant with 7.5 hours of TES were reported at 33 g CO₂eq/kWh [177], which is similar to the reference plant design in [178]. Life cycle GHG emissions for CSP technologies are impacted by plant design, including utilized cooling technologies, fuel and operating characteristics of any backup generation, and heat transfer medium [178]. Despite having life cycle emissions in the higher range for

renewables, particularly if gas-fired backup is utilized, CSP emissions are roughly 3 to 7% of gas- and coal-fired generation [55].

Deployment of solar PV and CSP is not expected to have any negative AQ impacts directly. Solar power technologies lack point-of-use pollutant emissions and life cycle pollutant emissions are largely determined by manufacturing, transport and installation processes, including the technologies used to meet energy demands of these parts of the life cycle [56]. Rates of SO₂ emissions for PV installations in the U.S. have been reported to vary from 158 to 540 mg/kWh across different technologies [56]. A review of PV production data from 2004 to 2006 from four major commercial PV types (multicrystalline silicon, monocrystalline silicon, ribbon silicon, and thin-film cadmium telluride) reported a range of SO₂ emissions from 0.158 to 0.378 g/kWh [167]. Life cycle emissions of NO_x for PV technologies are reflected by the grid mix of utilized energy in material production and have been estimated to total between 0.040 to 0.26 g/kWh [56,167]. A review of 5 life cycle assessments (LCA) for PM emissions associated with PV electricity generation in the U.S. found only one that was greater than 100 mg/kWh, reported to be 0.610 g/kWh [56]. Estimates in the upper range represented an area with low insolation rates and a greater reliance on coal for electricity generation, and regions with more favorable solar resources or cleaner electrical grids have lower emissions. It is estimated that a minimum of 89–98% of air emissions (GHGs, criteria pollutants, heavy metals, and radioactive species) associated with electricity generation could be avoided if electricity generated from PV replaces average grid electricity [167]. Localized impacts are possible if PV manufacturing facilities are located in urban air sheds and emissions from industry related activities should be considered. However, the majority of current global production occurs outside of the U.S. [181]. Life cycle emissions are reduced when PV is manufactured close to the point of deployment, with estimates in the literature suggesting that emissions from transport of PV panels to site locations represents a significant contribution [182,183]. While it is possible that natural gas back-up generation integrated into some CSP plants could produce direct emissions, the spatial and temporal operation of such facilities reduce the potential for worsening of urban AQ. Areas with high CSP potential are often in remote locations and many current and proposed CSP facilities are located far from population centers.

Conversion of wind energy into electricity through devices including wind turbines is well recognized as an environmentally beneficial source of power [184]. Wind power has the technical potential to contribute large amounts of electricity to the future U.S. grid [10,16,185] and could off-set substantial amounts of CO₂ emissions [150]. On the other hand, wind power is one of the most unpredictable, uncontrollable, intermittent and highly dynamic of renewable resources [186]. Thus, wind power requires complementary storage and dispatchable technologies to handle large amounts of wind penetration. Wind generated electricity entails very low GHG emissions with estimates for wind turbines ranging from 3–40 and 3–22 CO₂e/kWh for onshore [41,50,187–194] and off-shore [170,187,189,194–197] respectively, although turbine technology improvements could further reduce net emissions. Life cycle emissions are site specific and dependent on many factors including turbine size, wind conditions, and turbine lifetime. Relative to an average value for fossil energy generation, total avoided GHG emissions have been estimated at 35,265 and 122,961 tons for a 850 kW and 3.0 MW turbine over a 20-year service life, respectively [188]. Pollutant emissions associated with life cycle stages of wind power are also amongst the lowest of assessed technologies, estimated to total less than 100 mg/kWh for SO₂, NO_x, and PM [56]. No large-scale emissions of HAPs or other compounds of concern have been reported for wind turbine manufacturing or installment. Studies of high levels of wind power deployment have also reported important reductions in total NO_x and SO₂ [39] and wind farms have been estimated to reduce SO₂, NO_x and PM_{2.5} from natural gas power plants

[198]. It has been estimated that wind power has the ability to provide significant human health benefits from reductions in ambient PM_{2.5} levels [198]. The ability to provide utility-scale power with very low emissions yields significant GHG and AQ mitigation potential and justification of wind-related government subsidies often cite the societal benefits of reducing air pollution [199].

Conventional geothermal is a commercially proven technology that can be used for power generation, heat pumps, or other direct uses. Three major conventional geothermal technologies utilized to provide power include dry/direct steam plants, flash steam plants, and binary-cycle plants. Additionally, enhanced geothermal systems (EGS), involving the use of advanced drilling and fluid injection methods to add water and permeability in locations where heat is available, could increase potential resource availability. Life cycle emissions for all geothermal generation forms are reduced from coal and gas [200]. Estimates range from 5–57 g CO₂e/kWh for various plant designs [50,193,201,202]. Some hydrothermal reservoirs contain trace amounts of dissolved GHGs which are released to the atmosphere from direct and flash steam geothermal plants [203]. Though emissions of lithospheric CO₂ can be significant; emissions vary widely with respect to particular geothermal fields and average emissions are still much lower than any fossil energy source (see Table 12). Binary-cycle plants utilize a closed loop cycle and lack air emissions. An estimate of CO₂ emissions from geothermal power, including all stages from plant construction to decommissioning, reported emissions of 5.6 g CO₂/kWh, however the value did not include emissions associated with operation, which have been estimated to be about 30 g CO₂/kWh [193]. Fugitive CO₂ emissions are also a concern; however a study of emissions from hot dry-rock geothermal electricity calculated a CO₂ emissions factor of 37.8 g CO₂/kWh including fugitive emissions [170]. Direct pollutant emissions from geothermal generation, including NO_x and SO₂, are low compared to fossil generation and expansion of geothermal power is not expected to be associated with any AQ concerns [200]. Indeed, geothermal power has been shown to provide significant reductions in air emissions relative to coal and natural gas [204]. Previous AQ concerns caused by hydrogen sulfide emissions associated with geothermal generation have been successfully mitigated by commercially available control technologies. It is expected that geothermal technology will move away from hydrothermal towards larger EGS developments which have reduced environmental risks. Geothermal power derived from closed loop binary-cycle plants produce no air emissions of criteria pollutants and can be considered a direct emissions free source of electricity.

Generation pathways with fuels derived from biomass sources (i.e., organic material produced by a biological process) are an attractive renewable option due in part to the flexibility of energy provision, which includes many different feedstocks with opportunities and availabilities across a broad range of geographic areas [205]. Prospective resources include wood and woody wastes, trees, plants, grasses, aquatic plants and algae, agricultural residues, industrial wastes, sewage sludge, animal wastes, organic waste materials and municipal solid wastes (MSW) [206]. A key distinction differentiates dedicated energy crops (DEC) grown intentionally for use as an

Table 12

Life cycle emissions from geothermal power plants. Adapted from Reference [200].

Plant Type	CO ₂ [g/kWh]	SO ₂ [g/kWh]	NO _x [g/kWh]	PM [g/kWh]
Geothermal (Flash-steam)	27.2	0.1588	0	0
Geothermal (The Geysers)	40.3	0.000098	0.000458	negligible
Geothermal (binary-cycle)	0	0	0	negligible

energy resource from those available in waste or residue streams. Biomass-derived gasses (biogas) with energy potential can be produced via intentional or unintentional aerobic or anaerobic digestion or fermentation of biodegradable organic matter including manure, sewage sludge, and MSW [207]. Major sources of available waste streams suitable for digestion include wastewater treatment plants (WWTP), agricultural activities, and industrial wastes. Biogases range in composition, but generally are 50–80% methane, with CO₂ largely providing the balance, and have significant energy value [208]. Additionally, small amounts of nitrogen, oxygen, hydrogen sulfide and a variety of organic and element-organic compounds are present which can lead to emissions of criteria pollutants and HAP depending on chosen conversion device [209].

Fundamental generation strategies include direct combustion, co-firing, gasification, and pyrolysis. Current biopower systems most often include direct combustion of resources, e.g., solid biomass combustion for heat to produce high-pressure steam which is expanded through a generation turbine [210]. Feedstocks can be co-fired with fossil fuels in traditional power plants, displacing some fraction of the original fossil generation, e.g., solid biomass co-firing with coal, biogas co-firing with natural gas [211]. Gasification has been proposed as a method for effectively converting biomass into a useful fuel for power generation, CCHP applications, hydrogen production, and liquid fuel production [212]. Gasification differs from combustion in that solid fuels are partially oxidized in an oxygen starved environment at high temperatures to produce carbon char, and a flexible fuel gas composed of hydrogen, CO, CO₂, and methane [213]. Differing from gasification, pyrolysis is conducted around 500°C without any oxygen and can produce solid (char), liquid (tar), and gas products [213]. Gasification pathways can improve generation by employing gas-Brayton cycles in higher efficiency turbine engines, e.g., applications of biomass integrated gasification (BIGCC) in gas-turbine plants, but are currently limited by cost and require further development and demonstration at commercial scale [214]. Similarly, biogas fuels are often utilized directly as a fuel for combustion with common technologies including reciprocating engines and turbines. Additional conversion devices for biogas are the same as those for natural gas, and include direct chemical conversion via fuel cells [207]. Common conversion devices (e.g., reciprocating engines) are commercially available at the distributed and utility-scale, but generally entail lower efficiencies and higher pollutant emissions [215]. Gaseous fuels can also be upgraded and injected into existing natural gas pipelines to provide a source of renewable methane which can be utilized flexibly in numerous applications [216,217].

Life cycle GHG assessments conducted for biopower using biomass waste residues, DEC's reported reductions in GWP from coal and NGCC plants, including the potential for net negative emissions [218]. Co-firing with coal reduces CO₂ emissions relative to firing with coal alone, but not compared to NGCC, and could be an effective near term GHG mitigation strategy [219,220], particularly if advanced coal technologies are utilized [221]. Impacts for DEC are difficult to interpret as required changes in land- and water resource-use affect a variety of complex sequences including food resources, hydrologic cycles, biodiversity, emissions from upstream processes, and others, leading to dramatic variation in GHG estimates even for the same DEC [222]. Biomass residue is preferable to DEC in terms of net energy ratio and GHG emissions across feedstock and conversion technology pathways [218,223]. Feedstocks derived from waste/residue streams can achieve substantial GHG reductions via offset of traditional waste management practices that can result in emissions of gasses with higher GWP than CO₂ including methane and N₂O, e.g., avoidance of methane via decomposition and/or treatment of feedstocks. Very low GHG emissions for woody biomass relative to fossil generation have been reported using a dynamic LCA approach, however biomass pathway

emissions were higher than other renewable sources [170]. Still, pathways with appropriately selected DEC's grown on specific land categories have the potential to sequester carbon [224,225]. The use of some DEC's, including food crops, limit GHG benefits and greater reductions are attained from waste products or low-input, high diversity perennial plants grown on degraded or marginal lands [226,227]. In light of these and other environmental concerns associated with DEC's (land-use, water resources, soil, aquatic toxicity, competition with food, etc.), it has been proposed that only certain feedstocks be considered for renewable biopower including perennial plants grown on degraded lands abandoned from agricultural use, crop residues, sustainably harvested wood and forest residues, double crops/mixed cropping systems, and municipal and industrial wastes [228].

Biogas generation pathways (e.g., the treatment of animal manure using anaerobic digestion, collection and utilization of landfill gas) can dramatically reduce GHG via offset of the direct release of methane and other emissions and demand for grid electricity and process heat, displacing emissions from conventional energy pathways. The environmental impact from biogas systems is beneficial on a life cycle basis, with indirect environmental benefits (e.g., reduced emissions of ammonia (NH₃) and methane) sometimes in excess of direct benefits (e.g., reduced emissions of CO₂ and pollutants from biogas conversion) [229]. For example, traditional manure disposal methods (e.g., lagoons, outdoor storage) generate and emit methane and N₂O during the decomposition process. Similarly, landfill gas is comprised of 50–80% methane and the utilization via the installation of conversion technologies, largely as a result of regulations addressing recovery for flaring or energy use, has resulted in significant GHG emission reductions in the U.S. [230]. Emissions from biogas energy pathways vary significantly depending on properties of digested raw material, efficiency and characteristics of gas production, deployed end-use technology, efficiency of generation (electricity and thermal), and others, including the utilization of by-product heat [231]. The fuel-cycle emissions from biogas systems can vary by a factor of 3–4, and even by up to 11, for different systems providing equivalent energy [232]. A major determinant of GHG emissions from biogas systems are any emissions of methane due to leakage or venting, which if present, can add substantial warming potential [232]. Emphasizing the carbon mitigation potential of biogas fuels, Fig. 6 shows carbon intensities of CNG produced from biogas pathways relative to domestic fossil resources including high solids anaerobic digestion, animal waste, WWTP, and landfill production methods. The ability to offset the release of methane allows all biogas pathways to achieve net negative carbon

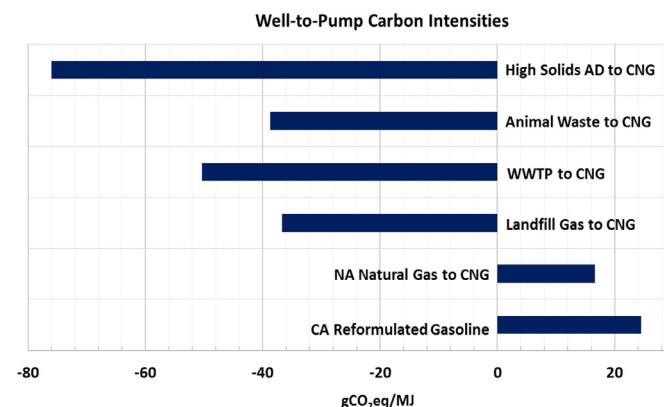


Fig. 6. Well-to-pump carbon intensities for compressed natural gas derived from various biogas feedstocks and conventional natural gas. CA reformulated gasoline also shown for comparison. Values calculated using the CA-GREET 2.0 Tier 2 model [233]. WWTP = waste water treatment plant, NA = North American, AD = anaerobic digestion.

Table 13
Life cycle GHG emissions for biopower pathways.

Biopower Pathway	LCA GHG Emissions [g CO ₂ eq/kWh]	References
Total	–1368–360	[41,170,234–251]
Woody Crops	4–360	[170,237,238,245,247–250]
Waste Stream	–633–320	[170,236–239,241–251]
Direct Combustion	22–120	[235–240]
Engine	14–110	[41,234]
Deployment with CCS	–594–(–1368)	[251,252]

intensities, although it should be noted that values do not include emissions from the point-of-conversion.

Table 13 provides a summary of life cycle GHG emissions reported for a range of biopower pathways. The potential for offset from waste stream resources results in the possibility of very low to even net-negative emissions depending on the resource and conversion pathway. The results also highlight the significant variation possible with DEC, potentially resulting in emissions at levels comparable to advanced natural gas generation and with other environmental concerns. Therefore, DEC biopower pathways must be developed carefully to achieve GHG and AQ benefits.

Biopower is distinct from other renewable resources in that some pathways (e.g., combustion and gasification) have direct pollutant emissions including PM, CO, VOC, NO_x, SO_x, acid gasses, and heavy metals comparable to or in excess of natural gas generation. Pollutant emissions generated per unit energy are related directly to the specific pathway and vary with respect to consumed feedstock, utilized conversion technology, the use of co-deployed pollutant controls, and others. Variation in resource types, characteristics (e.g., energy, ash, and moisture content), utilized conversion technologies, and end-uses yield a range of generated emissions. Direct pollutant emissions from conventional solid biomass combustion are generally favorable to coal, but often higher than natural gas. [218,253–255]. Biopower pathways with fluidized bed or gasification emit NO_x similar to NGCC plants, however emissions are higher if SCR is used in NGCC [218,219,256]. In addition to direct facility emissions, upstream emissions occur as a result of activities required to produce, process, and transport feedstock to facility locations [257]. When emissions are considered over a life cycle, species-level increases and decreases are observed relative to conventional fossil generation [218,258,259]. However, in contrast to GHGs, the regional nature of AQ dictates spatial and temporal emission patterns as the determinants of impacts and biopower systems require evaluation on a site-specific basis, rather than solely a life cycle approach. Introducing a biopower facility results in the introduction of an emissions source into a region which could have detrimental impacts on regional- and local-scale PM and ozone concentrations, as well as levels of HAP. For assessment of regional AQ impacts it is also necessary to develop an understanding spatially and temporally for emissions both directly from source contributors (e.g., exhaust of conversion devices, machinery used to collect/transport feedstock) and from those avoided (e.g., decomposition, flaring) in entirety. Therefore, biopower systems can have multi-faceted impacts on emissions and AQ when compared to reference fossil systems.

With similarity to natural gas, advanced conversion devices can support biomass and biogas fuel pathways. The most common technology for power generation of biogas resources currently is a reciprocating engine, largely due to lowest costs. However, the high emissions associated with such devices can cause difficulties meeting permitting requirements [260]. In particular, the use of fuel cells to directly convert chemical energy from biogas resources into power, heat, and fuels represents an opportunity to reduce emissions [261]. Suitable gaseous fuels include biogases and syngas

produced from gasification of solid biomass. In addition to low emissions, benefits of using biogas in high temperature fuel cells include high electrical efficiencies, water neutrality, and the generation of multiple useful products via tri-generation systems (e.g., waste heat, industrial steam, hydrogen) [262]. Fuel cells have been demonstrated with landfill gas [263,264], anaerobic digester gas from municipal WWTPs [265] and agricultural wastes [262]. However, the use of biogas in high temperature fuel cells requires additional considerations with a notable example being the clean-up of fuel contaminants which can degrade key components of fuel cells including the stack and fuel reformer, even at trace levels [266]. The cost of clean-up can represent a significant portion of overall cost from such systems [267]. Advances in the materials science of adsorption systems are needed to develop cost-effective purification of biogas including reducing reactor volumes within systems [266]. Other advanced conversion technologies suitable for biogas applications that offer potentially improved environmental performance include Stirling engines, organic Rankine cycle, and micro gas turbines [231].

4.2. Nuclear power

Nuclear power is the largest current source of domestic low-carbon power by a wide margin [29]. Electricity generated via nuclear processes is a proven, readily available generation strategy which requires no further technological advances prior to large-scale deployment and has reasonable economic competitiveness relative to fossil fuels and the other mitigation options considered [268,269]. However, considerable barriers exist to expansion of nuclear capacity including initial investment costs, lack of waste disposal programs, weapons proliferation concerns, and, perhaps most prominently, societal concerns regarding the safety of nuclear energy leading to social opposition to existing and planned nuclear plant operation [270,271]. Advanced nuclear technologies offer the potential for improved safety and security, and reduced cost and waste generation. Third- and fourth- generation reactor designs could alleviate challenges associated with nuclear power including generating little to no long-lived waste, lower life cycle GHG emissions, lower capital costs for plant construction, and no production of weapons grade material [55]. A complete description of different advanced nuclear fuel cycles is outside the scope of this work and a detailed overview can be found in References [55,272].

Nuclear generation produces electricity with very low life cycle GHG emissions relative to coal power plants [55]. Estimates vary with respect to specific plant types and fuel cycles but are consistently reported as comparable to some renewable technologies, and 1 to 2 orders of magnitude lower than fossil technologies (see Table 14) [273]. A comprehensive review reported a central value for the carbon intensity of nuclear energy of 10 g CO₂eq/kWh with an uncertainty range of 5 to 17 g CO₂eq/kWh [274]. An assessment of 103 life cycle studies reported a mean value of 66 g CO₂eq/kWh with the bulk of GHG emissions occurring upstream of the operational stage [166,275]. Additional studies have shown a range of carbon intensities with values as low as 1.4

Table 14
Reported life cycle GHG emissions for various nuclear power technologies and reductions from average coal and gas technologies.

Plant Type	LCA Emissions [g CO ₂ e/kWh]	References
Boiling Water Reactor	3.7–11	[41,50,284]
Pressurized Water Reactor	3.9–220	[41,276,278,280]
Fast Breeder Reactor	0.8–0.9	[276]
Fusion	23–44	[285]
Light Water Reactor	3.5–55	[41,279,286]

and as high as 288 g CO₂eq/kWh [41,43,44,50,166,273,275–282]. A subset of reported values and the reduction from both average coal and gas generation is provided in Table 14. Variation generally results from different enrichment methods and fuel cycles (e.g., once-through vs. recycled) and the carbon intensity of electricity used during various life cycle stages. Differences can be attributed to assumptions regarding the carbon intensity of the regional power grid, deployed enrichment path (e.g., centrifugation vs. diffusion), and chosen LCA methodology [279]. In response to uncertainty in reported emissions, Nian et al., (2014) proposed a value of 22.8 g CO₂eq/kWh using a new LCA methodology, roughly 2.5% from the median of globally reported LCA results [283]. It should be noted that even when considering the higher range of reported values nuclear power offers considerably lower GHG emissions than any other fossil option, including advanced coal and natural gas technologies.

Nuclear generation is devoid of direct pollutant emissions – though emissions occur from up- and down-stream life cycle stages including construction, fuel enrichment and transportation, and others. However, the magnitude of indirect emissions is comparable to those from renewables and the avoidance of direct emissions could significantly improve AQ, particularly in the displacement of current or new coal-fired capacity [34]. Reported life cycle pollutant emissions for a nuclear power plant are significantly lower than coal and natural gas [287]. Using the estimates for coal power from [54], nuclear power offers reductions of 95 to > 99% in SO₂, and 80% to > 99% in NO_x for conventional and advanced coal generation. In addition, nuclear power can achieve emission benefits relative to gas-fired plants, e.g., reductions in NO_x of 86% to 96% [54]. Similarly, reported PM_{2.5} emissions for nuclear plants are approximate to a reduction of 54 to 68% from natural gas and over four orders of magnitude less than coal [54].

Reductions in precursor emissions from coal and natural gas generation support the conclusion that increasing capacities of nuclear power would contribute to reductions in ground-level concentrations of primary and secondary pollutants. With similarity to GHG impacts, contributions to regional AQ improvements would be maximized by the displacement of coal generation. However, even the offset of natural gas generation could offer GHG and AQ co-benefits due to the low embodied emissions associated with nuclear energy. A factor that should be considered is the spatial discrepancy in life cycle emission profiles for nuclear relative to fossil which could have implications for AQ impacts, e.g., in regions supporting uranium mining or enrichment. Though a lack of robust modeling studies prevents an accurate quantification of impacts on ozone and PM_{2.5}, replacing coal and gas in many regions of the U.S. would likely be beneficial to both. The importance of GHG and AQ improvements achieved through nuclear power have been demonstrated via human health impact assessments [288]. Using historical production and global projection data; it is estimated that replacing fossil fuel combustion with nuclear power has prevented an average of 1.84 million air pollution-related deaths and could prevent up to 7.04 million deaths by 2050 [289]. In addition, achieved GHG emission savings are estimated to be 64 gigatonnes (Gt) CO₂-eq with reductions potentially rising to 240 Gt CO₂-eq by 2050. Notably, a transition to natural gas may not mitigate climate concerns and could result in more air pollution-related human mortality events compared to nuclear power [289].

4.3. Carbon capture and storage (CCS)

CCS involves the separation, removal, transport, and storage of CO₂ from energy-related processes in appropriate sinks including deep saline formations, depleted oil and gas reservoirs, un-minable coal beds, shale basins, and others. Potential opportunities for CCS deployment include large fossil fuel energy facilities (e.g., coal- or

gas-fired power plants), biomass energy facilities, major industrial sources (e.g., cement production facilities), synthetic fuel plants, and fossil-based hydrogen production facilities. A full review of the technologies, processes, and challenges associated with CCS is outside the scope of this work and can be found in [40,290,291]. Interest in CCS strategies often stems from the fact that large-scale deployment could facilitate GHG mitigation in tandem with the continued use of coal as it is cost-effective with large, proven domestic reserves [290,292]. Given the projected growth of fossil generation to meet increasing regional power demands [29], CCS has been acknowledged as an important technology in decarbonizing the U.S. power system [290]. Indeed deep GHG reductions may only be achieved if existing coal and gas plants are retrofitted with CCS technologies or retired [10].

Current CCS technology has the ability to capture approximately 80–90% of CO₂ produced during generation with the IPCC reporting 85% reductions in CO₂ per kWh for new PC or NGCC plants [293]. This value assumes secure storage with no leakage compared to a plant without CCS [149]. CCS processes are energy intensive necessitating additional fuel consumption for equivalent electrical output relative to a facility not equipped with CCS. This results in additional emissions of CO₂ and pollutants (essentially the energy used represents a loss in net efficiency of the plant) – although additional CO₂ is also captured with 90% efficiency [294]. Decreased efficiencies vary across technologies including NGCC (–11–22%), pulverized coal (–24–40%), and IGCC (–14–25%) plants [295]. Advanced technologies can reduce efficiency penalties and provide the potential for synergies. IGCC integration with CCS is technically attractive as CO₂ can be captured prior to combustion, with the concentration of the CO₂ in the syngas produced during gasification ranging from 30% to 32% allowing for more efficient collection [296]. Therefore, the net impacts of CCS must account for the efficiency penalty, capture efficiency, and additional life cycle emissions including leakage during storage. Studies have indicated that fugitive emissions and uncaptured indirect emissions could be substantial – about 10% of combustion emissions [149]. Using this value and assuming 30% more fuel is required, 90% capture of emissions is then equivalent to a net CO₂ emissions reduction of 76% from a given source. Also, fuel cell technologies that use hydrogen from fossil fuels that used CCS and integrated gasification fuel cell (IGFC) cycles have shown very high fuel-to-electricity conversion efficiency and low to zero efficiency penalty compared to systems without CCS [135].

A summary table of CO₂ emission impacts reported in the literature is provided in Table 15. The effectiveness of CCS varies with regard to specific plant configurations and fuels. For a 90% CO₂ capture efficiency GHG emissions are reduced by 75–84%, with IGCC technology favorable to NGCC [46]. However, despite reduced CCS performance, NGCC plants continue to have lower life cycle GHG emissions compared to traditional coal-fired technologies due the reduced carbon content of natural gas and higher net plant efficiencies [297]. Studies examining PC plants with CCS have demonstrated 71% decreases in GWP and up to a 79% GHG emissions reduction for PC utilizing lignite coal [252,297,298]. A review of PC coal-fired plants with post-combustion capture reported life cycle emissions from 79 to 275 gCO₂eq/kWh, relative to a range of 690 to 1100 gCO₂eq/kWh without CCS [299]. For IGCC plants with pre-combustion CCS, reported emissions ranged from 110 to 181 g CO₂eq/kWh versus 666 to 870 g CO₂eq/kWh for plants lacking capture. Oxyfuel power plants with CCS are reported to have life cycle emissions between 25 and 176 g CO₂eq/kWh. NGCC installing post-combustion capture are reported to have emissions ranging from 75 to 245 g CO₂eq/kWh with a reduction from non-capture plants of 51 to 80% [46,252]. The estimates at the lower range result from assumptions regarding emissions occurring during upstream fuel extraction, production, and transport (e.g., methane leakage) which could potentially lessen the benefits of natural gas CCS application. This

Table 15

Emission impact of CCS from coal and natural gas power plants. PC: Pulverized Coal, SCPC: Supercritical Pulverized Coal.

Technology	CO ₂ [Per kWhr]	CO ₂ [Life Cycle]	NO _x	SO ₂	P.M.	References
PC	–82 to –84%	–75 to –89%	+13 to +79%	–96 to +20%	–29 to –35%	[46,299–301]
SC PC	–72 to –87%	–	+25 to +44%	–61 to –95%	–35 to –49%	[46,301,302]
IGCC	–81 to –88%	–79 to –83%	–16 to +20%	+10 to +19%	–0 to –41%	[46,299,301,302]
NGCC	–59 to –83%	–51 to –80%	–50 to +17%	+0 to +100%	–42 to +25%	[46,299–303]

could be particularly relevant if, as discussed previously, non-conventional gas sources continue to meet a growing portion of domestic gas reserves. High estimates for coal-fired power are similar to advanced NGCC without capture, demonstrating the mitigation potential of CCS if coal continues to meet an important fraction of the domestic energy mix.

Shown in Table 15, equipping different plant technologies with CCS can both increase and decrease levels of emitted pollutant species by different mechanisms, and impacts must be considered by specific technology, fuel, and pollutant species. With similarity to GHG, additional pollutant emissions are generated from efficiency penalties associated with energy required for CCS processes including SO₂, NO_x, VOC, and PM – although such emissions are subjected to installed control technologies. Thus, most emission rates of pollutants (i.e., emissions per unit primary energy input) are expected to remain equal or be reduced by other mechanisms. However, increases in total pollutant emissions (i.e., emissions per electricity output) could result from increased total energy input [304]. The increase in total emissions for all pollutants could be assumed to be approximately proportional to the efficiency penalty associated with a given CCS technology. This could mean for example, that emissions of NO_x may not increase from an individual power plant but increase from the power generation sector as a whole via reduced efficiencies across the power plant fleet [300]. Note that fuel cell technologies that include CCS are particularly attractive from both a GHG and AQ emissions perspective, due in-part to the fundamental difference of fuel cell technology which maintains a separate compartment and flow for the fuel and oxidant, which makes CCS more efficient [305].

Thus, CCS deployment has the potential to worsen or improve regional or local AQ while providing substantial GHG mitigation, making it somewhat unique among considered strategies. The complex impacts of various CCS technologies on pollutant emissions make it challenging to assess definitively, as AQ impacts will be specific to technology type in regards to plant design and capture strategy, and to the utilized fuel(s). A study of the Dutch power sector reported that the introduction of CCS (post- and pre-combustion) increased emission of NO_x, PM, and NH₃, but significantly reduced SO₂ [291]. Similar results were demonstrated for deployment of three major capture systems (post- and pre-combustion and oxyfuel combustion) with impacts varying with respect to specific

technology deployed (e.g., SO₂ reduced 27 to 41%, impacts on NO_x varying from –20 to +15%, and PM ranging from –59 to +26%) [304]. Increased emissions could be particularly important with regards to the formation of ozone and PM_{2.5} as the largest reported increases are for NO_x, a precursor emission for both species. Contrastingly, SO₂ emissions are expected to be significantly reduced as a result of CCS utilization and could provide benefits to PM_{2.5} levels due to reduced sulfate PM formation and others including acid rain. The technology-driven nature of impacts gives value towards pursuing advanced generation technologies such as IGCC, IGFC, or fuel cells if CCS is deployed at a large-scale. It should also be considered that related pathways for carbon management including CO₂ re-utilization to embed CO₂ in a commercial products (e.g., synthetic fuels and chemicals, concrete curing) are advancing and may play a role in future GHG mitigation efforts [306,307]. Thus, tradeoffs and synergies exist with regards to GHG and AQ impacts across different CCS applications, both with regards to technologies and fuels.

4.4. Regional AQ and GHG implications of low-carbon generation options

It is important then, to measure the performance of current natural gas conversion technologies and infrastructure against current alternatives and to measure future natural gas and infrastructure use against future alternatives. The majority of renewable pathways on a life cycle basis produce very low-carbon power relative to natural gas and provide additional environmental benefits e.g., emission reductions for most renewable technologies exceed 80% even compared to a state-of-the-art NGCC without CCS (Table 16). Thus, it is also important to establish and support (e.g., policy, incentives) a vision for the evolution of the natural gas system to one that ultimately supports renewable electricity and a 100% renewable gas delivery system. Undeniably, the optimal sustainability goal for energy systems is to source all primary energy from renewable resources and convert such energy with zero GHG, and zero pollutant emissions, environmental disruption, water demand, or waste. While reduced significantly from coal generation, even the best current natural gas generation options produce emissions of CO₂ and pollutants at levels that contribute to climate and regional AQ concerns [34]. The carbon footprint of both conventional and advanced

Table 16Life cycle GHG emissions for renewable resources relative to state-of-the-art NGCC. *Assumed at 358 gCO₂e /kWh from Reference [308].

Renewable Technology	LCA Emissions (g CO ₂ e/kWh)	Reduction From NGCC*	References
Wind (offshore)	3–22	94–99%	[44,170,187,189,194–197]
Wind (onshore)	3–40	89–99%	[41,50,187–194]
Solar-PV Thin Film	19–95	73–95%	[163,167–169,309]
Solar-PV Crystalline	20–104	71–94%	[50,162,164,168,170–172]
Solar-CSP	12–241	33–97%	[174–179]
Geothermal	5–57	84–99%	[50,193,201,202]
Ocean-tidal and wave	2–56	84–99%	[193,310,311]
Hydropower	1–39	89–99%	[41,44,312–315]
Biopower	–633–360	0–277%	[41,170,234–251]
Biopower with CCS	–1368 to –594	266–482%	[251,252]

fossil natural gas generation is greater than many other low-carbon strategies including nuclear power and most renewable resources. Therefore, long-term sustainability requires that the natural gas system evolve to support and complement other zero GHG and zero AQ emissions technologies.

In addition, the majority of the so-called “advanced” natural gas technologies presented herein (e.g., fuel cell systems) have no or very low point-of-use pollutant emissions and can potentially offer regional AQ benefits as they become part of the natural gas system evolution. Fig. 7 shows the relative potential for GHG mitigation and regional AQ improvement for current and advanced natural gas generation methods operating on fossil natural gas, and the other low-carbon generation strategies considered here. Intermittent renewable resources including wind and solar have high potential for GHG and AQ co-benefits, particularly if advanced zero- and near-zero complementary generation strategies are used. Similarly, nuclear power generation, while it has the challenges discussed previously, represents an option for GHG mitigation and AQ improvement that is greater than advanced natural gas generation. Biopower strategies offer the potential for the highest GHG benefits (i.e., potentially net-zero or net-negative emissions) and very high AQ benefits due to the ability to offset emissions from traditional management practices and energy conversion methods. However, this requires careful design of conversion pathways as the potential for direct emissions and other impacts from biogas and biomass resource pathways can result in detrimental AQ impacts. The deployment of CCS technologies may reduce GHG emissions from coal plants relative to natural gas generation without CCS, but the commercial success of CCS would likely facilitate the use with NGCC as well. The AQ impacts of CCS are not necessarily beneficial with conventional technologies (e.g., PC and NGCC plants) due to the potential for AQ emissions increases associated with efficiency losses. The opportunity for natural gas generation to provide AQ benefits together with GHG reductions when using CCS is most significant for advanced generation methods. For example, fuel cell systems can incorporate CCS with much lower efficiency penalty compared to traditional generation due to separated fuel and oxidant compartments. In addition, fuel cells, advanced NGCC, and CCHP strategies are associated with higher potential for AQ benefits than CCS of traditional technologies and some biopower pathways. However, the challenge of attaining deep GHG reductions while still using fossil gas supply limits the mitigation potential of such devices. It is therefore reasonable to select renewable resources or even nuclear power generation as a

preferred GHG mitigation and AQ improvement strategy when directly comparing emissions and other environmental impacts. The role of the natural gas system then is to evolve to increasingly support the limitations of these zero emissions technologies.

Additionally, understanding implications for regional AQ is not as straight forward due to the complexity associated with the formation and fate of atmospheric pollution. The dynamics of formation are complex and predicting how technologically-driven pollutant emissions translate to changes in ground-level concentrations is challenging. Strategies to reduce GHG emissions will also affect regional sources of pollutants and vice versa. Such shifts could be in quantity (i.e., net reduction or increase) and/or chemical composition (i.e., different pollutant species) and/or dynamics (i.e., time series of release). Ambient concentrations are determined by multiple factors, including the quantity, location, and timing of direct emissions from sources, and various atmospheric processes including transport, dilution, deposition, and chemical reaction. Emission impacts in the electricity sector directly depend upon the displaced generation source which is complicated by variations in technologies, fuels, and demands that comprise regional power grids. Furthermore, spatial and temporal shifts in emission patterns can influence the formation and fate of secondary pollutants that carry human health consequences, including ozone and PM_{2.5}, with multifaceted atmospheric chemistry that ultimately determines the formative species level impacts. Additionally, emissions themselves are insufficient to create AQ problems, which require certain features of regional geography and meteorology coupled with population exposure. As a result, AQ conditions are dependent upon natural factors, including topography, meteorology, biogenic emissions and climate; in addition to the local emissions signature associated with anthropogenic sources. Thus, predicting how technologically-driven pollutant emissions impacts translates to changes in atmospheric concentrations requires more than a simple emissions quantification and comparison, even at the life cycle level, as this fails to capture these important sources of impact.

Using ozone as an example, NO_x emitted as nitric oxide (NO) rapidly reacts in the atmosphere to produce nitrogen dioxide (NO₂), which further reacts with VOC in the presence of sunlight via a series of photochemical reactions involving hydroxyl-, peroxy-, and alkoxy radicals to form oxidants including ozone and peroxyacetyl nitrate (PAN) [316]. Additionally, regions can be either NO_x- or VOC-limited (generally VOC-limited areas encompass urban centers with high anthropogenic emissions and NO_x-limited areas include rural locations) which directly impacts resulting variations in ground-level ozone from the initial reductions or increases in emissions [317,318]. Similarly multifaceted relationships exist between direct emissions and atmospheric PM concentrations [319,320]. Thus, predicting how implementation of a generation strategy will impact ozone or PM based off approximations of emission reductions or increases is quite limited. In fact, a thorough assessment of such impacts requires characterization of technological information to develop detailed spatially and temporally resolved pollutant emission fields to serve as input for atmospheric models that can account for chemical and physical atmospheric processes, e.g., mixing, transport, and photochemistry [321].

While many studies have been conducted for the power sector utilizing atmospheric modeling, e.g., for DG implementation [123,322,323], coal power plants [34,69,70] and others [102,324], additional assessments are needed to further understand AQ impacts that result from changes in emissions. Therefore, a significant research need exists for studies involving realistic scenarios of various future power generation mixes across a range of possible socio-economic and techno-economic drivers. Emissions should be resolved spatially and temporally, and would be best if attained via modeling that accounts for the dynamic dispatch of generators and utility grid network constraints within a specified network, as well

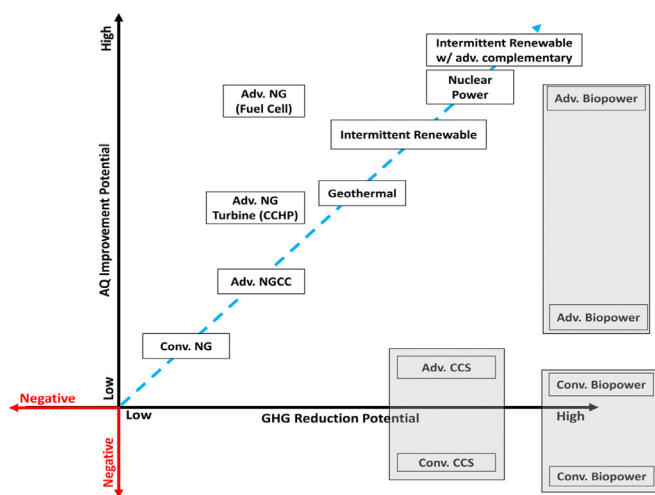


Fig. 7. Relative potential for GHG mitigation and AQ improvement for current and advanced natural gas generation utilizing fossil natural gas resources and additional low-carbon generation methods.

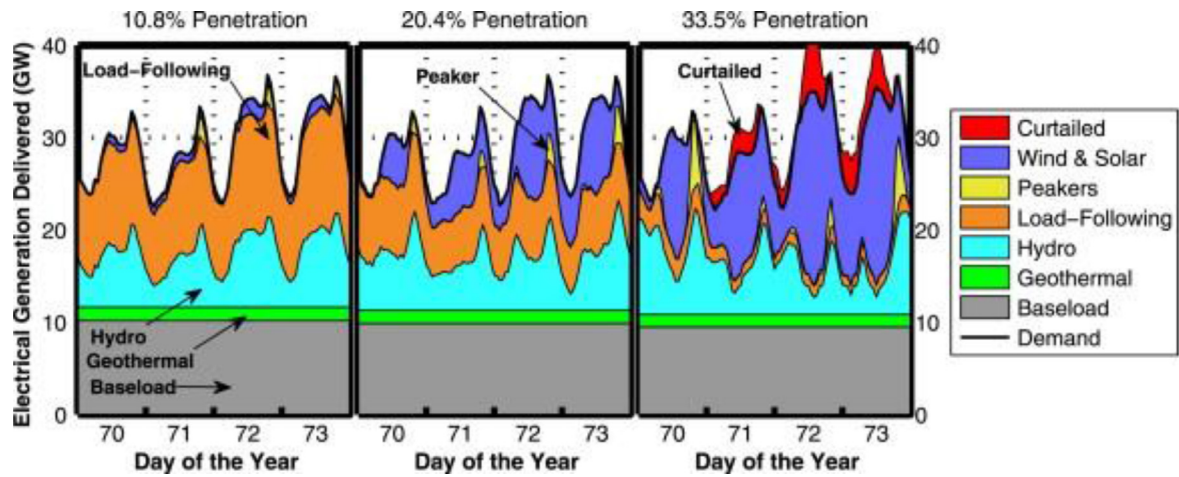


Fig. 8. Impact of grid integration of increasing penetrations of intermittent renewables into the California electrical grid. Reprinted from [327] with permission of Elsevier.

as dynamic emissions rates from all incorporated generators. Finally, three dimensional AQ models should be utilized to quantify and assess resulting changes in atmospheric pollutant concentrations (including secondary pollutant formation and transport phenomena) that result from the technological changes considered.

5. Support of renewable resources to achieve emission reductions

Natural gas is unique amongst fossil fuels with regards to the benefits of complementing renewable resource integration. These benefits include (1) the dynamic ramping ability of modern natural gas power generation methods, (2) low criteria pollutant and GHG emissions relative to other fossil fuel generation methods, particularly during dynamic operation, (3) technical ease with which renewable fuel alternatives such as biogases can be substituted, and (4) potential for transition to 100% renewable fuel (e.g., biogas, renewable hydrogen) injection, storage, and delivery in the future.

5.1. Low- and zero-emission complementary generation

Increasing the capacity of renewable resources will require overcoming challenges associated with electricity system incorporation. The existing structure of the U.S. and regional electrical grids and the nature of renewable resources (e.g., many with characteristic intermittencies, uncontrollability, etc.) cause difficulties for managing load balancing and other key operational parameters that can result in undesirable outcomes, e.g., enhanced power curtailment, increased costs, and large required installed capacities [325]. This is particularly true regarding the integration of high levels of wind and solar generation in terms of systems-level operation [153,325]. Wind and solar resources are characteristically intermittent at multiple time scales (e.g., hourly, daily, seasonally) and complementary strategies are needed to ensure satisfactory systems-level operation – most notably balancing generation with demand. Grid operation must accommodate all load demand conditions irrespective of the availability of renewable power and, due to the rapidity at which intermittent resources come online and/or dropout, additional reserve capacity and ramping capabilities must be constantly available [326]. As a result, high penetration of renewable power dictates rapid responses by controllable generators (mostly fossil fueled today) and energy storage or other complementary technologies. Regardless of the amount of each complementary technology deployed it is likely that high penetration of wind and solar power will lead to greater dynamic operation of existing fossil generators.

In California, natural gas power plants are most often used to provide the complementary generation needed to balance renewables and load including those with load-following or peaking capabilities⁵ [38]. In other regions of the U.S. such capabilities may be required from generators with higher emission rates than natural gas plants, including coal power plants. Natural gas load following and peaker plants are often simple cycle steam or combustion gas turbines with lower efficiencies and higher emissions than baseload plants [66]. Natural gas baseload generation is often provided by higher efficiency and lower emitting NGCC. Consequences of wind and solar integration can include increased load following and peaking generation accompanied by a decrease in generation from baseload generators visible in the modeled generator-level impacts from increasing integration of wind and solar resources in the California grid presented in Fig. 8. Additionally, increasing levels of curtailed generation are observed that could have economic and energy consequences.

The system-wide impacts related to intermittencies of renewable integration can have unwanted and unforeseen GHG and pollutant emission impacts, in addition to the positive benefits of offsetting direct emissions from fossil generators [328]. Emission rates of GHG and pollutants per unit energy of electricity from natural gas power plants increase during dynamic operation events including cycling, ramping and start/stop conditions [329,330]. Ramping has deleterious impacts on plant efficiency (and thus emissions) by two mechanisms – (1) heat rates are higher for ramping resources at full load relative to units designed to be operated at fixed levels of output and (2) the operation of gas plants at partial load results in a higher heat rate relative to full load operation [331]. All of the described stages of dynamic operation (i.e., start/stop, cycling, ramping) result in pollutant and GHG emissions that otherwise would not have been generated. The large-scale electrification of energy systems could potentially exacerbate the issues previously mentioned by increasing the size and altering the shape of the load. Therefore, it is not accurate to assume that increasing the levels of intermittent renewables will have no detrimental AQ impacts as utility grid network integration of these resources requires balancing power that includes emissions from fossil generators that could potentially reduce expected emissions benefits or even yield localized increases in emissions from certain power plants [328,332–335].

⁵ Such plants are typically associated with marginal generation or the last plants to come online in the loading order. Marginal generation is typically impacted by renewable resource integration.

Future complementary generation can be provided by advanced technologies and strategies in place of current fossil complementary generation to improve efficiencies and avoid undesirable emission impacts. Fig. 9 displays the emissions of NO_x per unit energy for traditional and advanced heat engines and fuel cells operating on natural gas that represent potential technologies for load balancing intermittent renewables in place of natural gas load following and peaking units in California. Emissions of NO_x from NGCC are much lower than both – particularly for new state-of-the-art NGCC relative to existing load following and peaking generation. Load following and peaking plants may also require up to several hours to start or stop and therefore often must be run (i.e., cycled) to be ready for any renewable generation drop off. Contrastingly, if available renewable generation increases then the available output from gas generators may be unutilized even though they continue to operate. Therefore, increasing the amount of total generation from load following and peaking plants at the expense of baseload plants (as shown in Fig. 8) can result in additional GHG and pollutant emissions [336]. In contrast, fuel cell generation results in negligible emissions relative to other devices including combustion turbines, microturbines, reciprocating engines and NGCC. Technologies utilizing combustion (i.e., reciprocating engines, combustion turbines, microturbines) can also operate with lower emissions than load-following and peaking generation but may require pollutant control technologies to achieve minimum emission limits. For example, microturbines must be integrated with CCHP to achieve reductions in GHG, and must be integrated with SCR technology to achieve low criteria pollutant emissions [35,125,126].

Fuel cells can deliver peaking or intermediate load-following service, which can prevent the need for new transmission and distribution infrastructure and provide peaking capacity in emissions and/or electricity infrastructure constrained areas. Fuel cells have been evaluated for providing grid support in energy systems with very high levels of intermittent resources [338] including a 100% renewable energy system in support of climate mitigation [339]. Future fuel cell or fuel cell hybrid systems can provide load following capabilities in tandem with low emissions with proper system and control configurations [340]. Clusters of 10–100 MW scale fuel cells installed at distribution substations have been proposed as a method of supporting high penetrations of intermittent renewables through the provision of baseload and load following services with very low NO_x and CO_2 [38]. Fuel cells can also be integrated in the residential sector to support and complement solar PV deployment

[341]. Power conditioning inverters in fuel cell systems that are needed to transform DC electricity into AC can be used for system power factor correction and voltage support. The load-following capabilities of fuel cells are particularly important in regions with projected increases in intermittent wind and solar power generation that will necessitate increasing amounts of clean, efficient, load-following power generation. This would maximize the GHG reductions of renewable resources while limiting any negative effects on regional AQ that the renewable intermittencies would otherwise introduce.

Therefore, emissions must be considered at the systems-level rather than simply comparing life cycle or direct emissions at the point-of-generation. For example, while it is certain that renewables must play a central role in a sustainable energy system, large-scale integration in regional energy systems is not a simple matter. This is particularly true for wind and solar power, which are likely to comprise the largest portion of future renewable capacity in most regions around the world with potential unforeseen electrical grid impacts including sites of emissions increases leading to AQ worsening. For example, emissions of NO_x and VOC from conventional load following and peaking generation could contribute to increases in ground-level ozone concentrations in regions adjacent to power plants. Similarly, direct and secondary emission impacts could drive increases in ground level concentrations of PM. Thus, in the absence of enhanced flexibility and intelligence of the grid and the presence of low or zero-emitting and controllable complementary strategies, high levels of renewable integration could yield some localized worsening in regional AQ. This must be considered in the context that overall AQ impacts of high renewable power use will be largely beneficial as a result of net emission reductions compared to fossil generation. Therefore, the worsening described herein is directly referencing localized areas around impacted fossil generators that would be forced to operate in a highly dynamic fashion to complement renewable intermittencies. This scenario could have particular importance in many urban areas due to high population exposure and for regions currently experiencing challenges meeting ambient air quality standards. Similarly, the GHG impacts of renewables will almost certainly result in net reductions in emissions – but the total reduction could be increased and AQ benefits preserved if emissions from complementary generation could be avoided or minimized.

5.1.1. Other low- and zero-emission complementary generation

In terms of providing complementary generation, energy storage technologies are a key strategy in support of renewable integration. Energy storage, which also represents a complementary option for balancing intermittent resources, also can potentially reduce GHG emissions from natural gas by 21–98% with life cycle emissions ranging from 6–292 gCO_2/kWh [312]. A wide range of technologies are available or under consideration for the support of renewable energy, with a comprehensive overview provided in [342]. It is well understood that energy storage has the potential to support renewable energy and provide environmental benefits [343]. Energy storage devices are more responsive than conventional generators and costs are becoming more competitive with other sources of generation [344]. Further, they can provide emission benefits as many have very low to no emissions during operation, e.g., batteries, flywheels. Energy storage can then have GHG and AQ benefits by reducing emissions associated with load balancing and spinning reserve via replacement of required fossil fuel backup generators [345,346]. Energy storage can also reduce emissions by time-shifting loads away from peak demand, reducing generation from peaking and load following plants in place of base-load generation [347]. The following pathways are recommended for

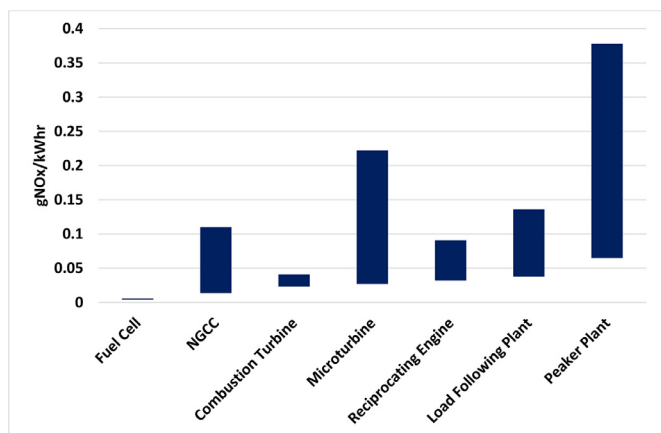


Fig. 9. Emissions of NO_x from natural gas power generation devices to provide load balancing services for intermittent renewable resource integration. Data for NGCC from [36,40,337], data for fuel cell, combustion turbine, reciprocating engine, and microturbine from [35], data for load following and peaker plants from [38].

providing dispatchable power to support renewables in [348], and would likely provide very low to zero emission complementary generation with AQ and GHG benefits.

- Expand the use of high-capacity batteries including the development and commercialization of advanced technologies such as solid state and flow batteries, supercapacitors and superconducting magnetic energy storage.
- Develop high-capacity compressed air storage resources including underground caverns where geologically and technically feasible.
- Expand the use of thermal energy storage mechanisms including molten salts, solids, and other high heat capacity media, or via phase change.
- Construct high-capacity pumped-hydro storage facilities where feasible.
- Develop large-scale flywheels for direct storage and recovery of kinetic energy.

However, large-scale deployment of energy storage faces barriers including, among others, economics, regulatory and utility structures, and siting of facilities [349–351]. These barriers complicate an understanding of when and how the very large capacities needed to match increasing levels of renewables will become available. Therefore, while providing complementary generation from advanced strategies, including energy storage, represents an important and valuable long-term goal, natural gas generation is currently the most feasible method of balancing fluctuating renewable power with load and may continue to be so in the near- to mid-term.

Further, energy storage may not always be the environmentally preferred option for providing reserves if not managed properly, even if it is assumed to have no operational emissions [352]. For example, if energy storage enables system operators to use lower cost generation with higher emissions that would otherwise not be possible due to reserve requirements [353]. Analysis of adding energy storage to a power system concluded emission impacts were highly case-dependent [354]. In systems with high renewable penetration levels and significant curtailment energy storage did provide emission reductions. However, in other systems emission impacts were reported to be positive, neutral, or negative. It should be noted that the most appropriate comparison for the discussion here is the high renewable integration scenario and the use of otherwise curtailed power. In such a case energy storage is likely to provide emission reduction benefits by making available renewable electricity to meet demand otherwise satisfied by dispatchable generation.

Additional options for low environmental impact complementary generation includes Smart Grid technologies, demand response, clean dispatchable power generation, and other strategies including transportation sector integration through vehicle-to-grid services. Smart Grid technologies offer benefits relative to the current grid; including improving power quality and reliability, reducing costs, improving efficiency and conservation, facilitation of increased renewable resources, and advanced technology penetrations, and enabling enhanced supply- and demand-side energy management [355]. Implementation of Smart Grid technologies can have important direct GHG and pollutant emissions benefits by improving systems-level efficiency, thus reducing levels of necessitated generation [356–358]. Vehicle-to-grid strategies also can provide emission benefits, essentially functioning as a form of battery energy storage [359]. As with other forms of energy storage, these strategies will require further advancement, both techno-economically and in social acceptance, but represent an optimal method of providing complementary generation in place of fossil fuels.

5.2. Low carbon renewable fuel storage and transmission

An additional avenue of support for renewable resources in pursuit of GHG and AQ reductions includes the use of existing natural gas infrastructure to transport, store, and distribute renewable gaseous fuels with two prominent examples including biogas and hydrogen sourced from renewable resources. Within the U.S. a robust and established infrastructure network exists to support the natural gas industry, including greater than 300,000 miles of transmission pipelines, gathering systems, storage sites, processing plants, and distribution pipelines [25]. Gaseous fuels can be upgraded and injected into existing natural gas infrastructure to provide a source of flexible fuel which can be utilized in various end-use applications [216,217]. The use of renewable gaseous fuels as energy resources is desirable due to potentially net-zero GHG intensities, reduced pollutant emissions and additional energy and environmental benefits [360]. In addition to directly providing fuels for energy services, use of low-carbon pipeline fuels can provide additional emission reductions, e.g., avoidance of emissions associated with the construction or expansion of transmission infrastructure for hydrogen or electricity. The use of renewable gaseous fuels can further support and enhance other forms of renewable energy including renewable power generation from intermittent resources. Relative to renewable resources and electrification alone, the addition of low-carbon gaseous fuels distributed via existing natural gas pipelines is complementary in meeting future GHG mitigation goals by [361]:

- Assisting in reducing emissions from sources that experience greater challenges to electrifying (e.g., industrial process heating, heavy duty vehicles, aircraft).
- Supporting intermittent renewable power integration by providing a form of energy storage amenable to large-scale energy magnitude and long-duration storage to balance load and demand.
- Offsetting the need for new infrastructure (e.g., electric transmission wires) construction by enabling continued use of existing gas pipelines.
- Enabling widespread use of the renewable low-emissions fuel in all sectors of the economy due to the pervasiveness of the natural gas grid.
- Helping reduce technological risk and improve flexibility for decision makers.

Therefore, the natural gas system inherently possesses features that are, and will be, valuable to ultimate sustainability, perhaps offering the only technically feasible option (and certainly one of the most cost effective options) for achieving massive and long-term storage of renewable electricity, and achieving 100% emissions-free energy conversion in all sectors of the economy and especially the challenging sectors (e.g., heavy duty transport and industry).

5.2.1. Renewable fuel injection in the grid

The potential for increased biogas resources is significant e.g., biogas generation could potentially be expanded to provide 3 to 5% of the total domestic natural gas market [362]. Following clean-up for compounds including siloxanes and hydrogen sulfide, biogas is notably similar to fossil natural gas in chemical composition (i.e., a renewable biological source of methane) enabling direct interchangeability in the natural gas system for sources of demand. Upgraded biogas can readily be injected into the existing natural gas system, facilitating the storage, transport, and distribution of a renewable gaseous fuel. This further allows for biogas to be transported to numerous possible end-uses with potential for higher value than that which is available only local to the biogas resource sites [363]. For example, pipeline biogas could supply a portion of

the resources utilized by a centralized NGCC with benefits of scale including reduced emissions [260] and potentially lower cost relative to generation on-site at resource locations, although economics and emission impacts of biogas utilization strategies are complex and depend on many factors [360,362,364]. However, the expanded use of biogas in the U.S. would benefit from nuanced policies and programs supporting site-specific evaluations and actions, as opposed to generic approaches [360].

Biogas is generally 55–65% methane with the remainder composed of CO₂, fractions of water vapor, traces of hydrogen sulfide and hydrogen, and other contaminants including siloxanes. An important step in facilitating long distance transport from an economic and energy sensibility standpoint is increasing the energy content [365]. Additionally, attaining pipeline quality gas for injection represents a techno-economic hurdle for biogas at present. Biogas composition and quality differ across sources of origin (e.g., landfills, manure digesters, gasifiers, etc.) with implications for various end-uses [366]. This requires site- and case-specific selection of upgrading technologies dependent on factors including product purity and impurities, methane recovery and loss, upgrading efficiency, and investment and operating costs [367]. Regulatory and technical standards associated with the acceptance of biogas into pipelines differ by state and country. For example, California gas contaminant standards for investor-owned utility gas are comparable to other States and have been found to be reasonably achievable using conventional gas clean-up technologies [368]. Contrastingly, minimum energy content standards are higher than other locations, and the majority of conventional and emerging biogas upgrading technologies may not provide acceptable gas [368]. Additionally biogas cleaning and upgrading costs can be high, resulting in the economic unfeasibility of pipeline injection for low quantity biogas producers operating small anaerobic digestion systems. To address this issue, the following recommendations were put forth in a report to the California Energy Commission as an example of potential research and regulatory steps in support of biogas utilization and gas grid injection [368]:

- Reduce the energy content requirements for pipeline biomethane from 990 to 960–980 Btu/scf on a HHV basis.
- Collect data on concentrations of contaminants of concern in current California natural gas supply including instate and imported sources.

- Address costs and provide financial support and incentives for biogas upgrading and pipeline interconnection and for small-scale DG systems.
- Develop a streamlined application process (e.g., standardized forms, agreements) to minimize time and resources spent by all parties.

Hydrogen can be produced with very low emissions from a diverse selection of renewable pathways including by electrolysis from electricity generated by wind and solar technologies, the processing of biogas resources, and via direct solar water splitting in a process called artificial photosynthesis [369]. Although not renewable, hydrogen could also be produced from additional low-carbon pathways including cogeneration of electricity and hydrogen via high-temperature nuclear reactors and fossil pathways with the inclusion of CCS, e.g., coal gasification and SMR of natural gas [370]. Even the most common current method for producing hydrogen, SMR of natural gas, provides a relatively low GHG and AQ emissions pathway to produce a fuel that has no GHG and no AQ emissions in its end use in a fuel cell, for example [371]. While current hydrogen production methods generally rely upon fossil pathways, progressive shifts towards renewable and other low-carbon strategies can allow for the production of hydrogen in increasingly sustainable methods.

A notable hydrogen strategy for both the production of very low-carbon fuels and the support of intermittent renewable integration is the electrolysis of water via otherwise curtailed renewable electricity (most often wind and solar power), a concept often referred to as power-to-gas (P2G) [372]. Generally, the P2G strategy is a means of linking the electrical grid and the natural gas grid by converting electricity (typically surplus renewable electricity) into a grid compatible gaseous fuel [373]. An overview of P2G system integration with renewable electricity is shown in Fig. 10. Excess available wind and solar power can be fed to battery energy storage for short-term storage, or sent to an electrolyzer to produce renewable hydrogen, which better enables long-term and massive energy storage. Produced hydrogen can then be stored in dedicated facilities and used on-site when needed in stationary and mobile applications achieving emission reductions. For example, hydrogen can be used to power fuel cell electric vehicles with negligible pollutant emissions in place of petroleum-fueled vehicles or utilized in stationary fuel cells to efficiently generate on-site power and heat. Hydrogen

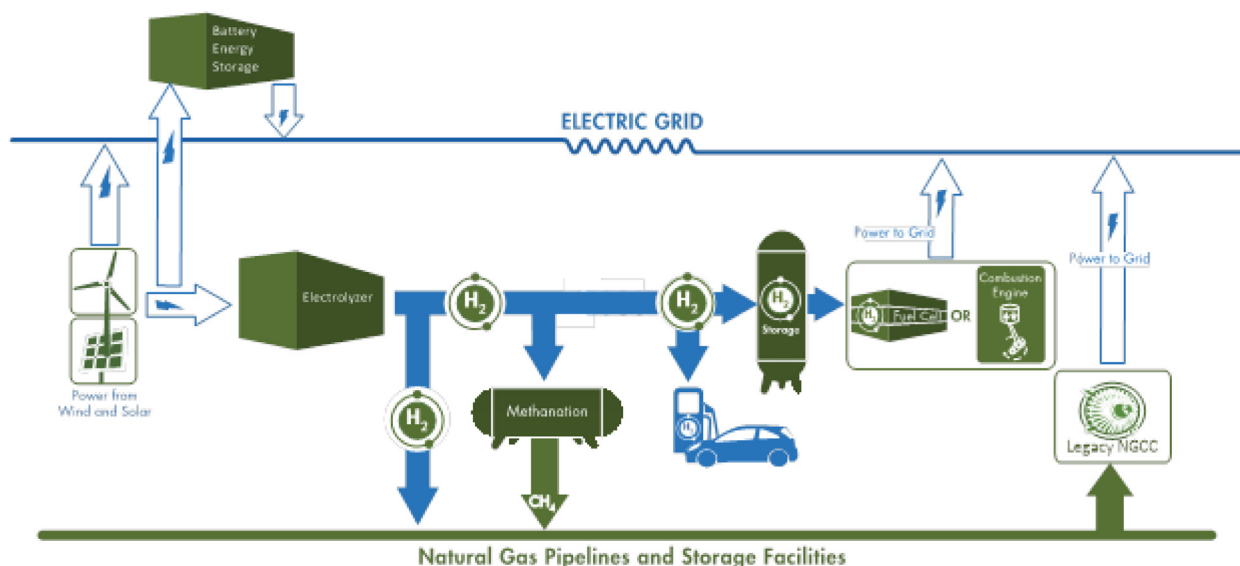


Fig. 10. Overview diagram of Power-to-Gas strategies enabling the storage, transport, and potential end-uses of renewable electricity as a natural gas grid compatible fuel.

may also be injected into the natural gas system directly, or reacted with an external carbon source in a methanation reaction to produce renewable methane. Similarly to hydrogen, this renewably produced methane can be injected into existing natural gas storage and distribution grids, used on-site as a stationary generation or vehicle fuel, or utilized in other established natural gas end-uses.

An important ability of P2G is the potential to support the deployment of electrical systems with very high levels of renewable electricity (e.g., 85%) by providing a means of long-term energy storage potentially from the sub-megawatt to gigawatt power scale and comprising up to 10s of terawatt hours of energy [374,375]. Additionally, electrolyzers utilized in P2G systems can provide grid functions including rapid demand or supply response, spinning reserve, and frequency and voltage regulation. Typically, the most commonly considered renewable energy source for P2G systems is wind and solar power that become difficult to otherwise manage at high use levels [372]. P2G can facilitate hydrogen production during periods of excess renewable generation that would otherwise be curtailed, which assists in addressing the spatial and temporal challenges discussed for renewable energy [375]. Additional benefits of P2G in energy storage include siting flexibility, sub-second response times, and minimal adverse environmental impact in both the production and end-use of the renewable fuel, especially if the hydrogen is converted ultimately to electricity in a fuel cell for either transportation or stationary power applications [376].

The injection of hydrogen directly (i.e., without methanation) into the existing natural gas system is being considered as a means of facilitating the production, storage, and transport of large quantities of a renewable fuel that can be used as an energy source by a range of zero-emitting end-use devices [133,377]. Use of the existing natural gas system also represents a solution to the key barrier of current lack of hydrogen infrastructure [378]. However, due to the differences in chemical properties between hydrogen and natural gas, concerns exist including safety, leakage rate and dispersion, and materials degradation including embrittlement of pipeline steel [379]. The amount of hydrogen allowable in the natural gas system varies by region and typically ranges from 0 to 12% by volume [373]. However, the majority of these concerns are being actively addressed through various research and development projects around the world and it is possible that in the future hydrogen may be injected at increasingly higher concentrations as mixed with natural gas.

Methanation of hydrogen to produce synthetic methane has some advantages over simply utilizing hydrogen, namely the ability to serve as drop-in fuel with regards to current infrastructure and use in existing natural gas consuming technologies. Essentially, synthetic methane is completely usable in the existing, technically mature natural gas infrastructure, e.g., can be feasibly injected into existing natural gas grids without many of the challenges associated with hydrogen [380]. This results in economic benefits as no new investments are required for transport, storage, and utilization, but also is beneficial in avoiding issues of obtaining permission from authorities and general public acceptance [381]. Different methods for methanation include both biological and catalytic reactors with implications for achievable gas quality, reactor volume, and the complexity of process technology required [373].

Major technical and economic barriers exist for P2G that must be overcome, however. For example, though water electrolysis has existed commercially for several decades only approximately 4% of global hydrogen supply is derived from such pathways [382]. Considering electrolysis, improvements in efficiency during transient operation and reductions in capital cost are needed [373]. Currently, alkaline electrolysis is the lowest cost and most reliable technology, but has limited efficiency improvement and cost reduction potential. PEM electrolysis can offer improved transient performance and have a simple modular design, but cost reduction and technical

improvement including membrane lifetime of PEM electrolyzers is needed. Similarly, solid oxide electrolysis can offer the benefits of very high efficiencies but will require further technical development prior to commercialization including increased lifetime [383]. If hydrogen storage is utilized this can also contribute to high costs [384]. Methanation as a viable commercial step would benefit from techno-economic advancement including an improved understanding of dynamic reactor operation, advancement in cool fixed-bed reactors, and others [373,385].

An additional issue associated with injection of both biogas and hydrogen into the existing natural gas supply is the potential impact on end-use combustion performance [385]. Current end-use devices (e.g., turbines, engines, industrial burners, residential and commercial appliances) are optimized for use on pure natural gas. Altering the composition of the supplied fuel could result in alterations to key parameters including heating value, Wobbe-index, knock phenomena, flame stability, blow off limits, and flashback [385]. Given the scope of this review, perhaps the most important concern is associated with potential changes in emissions. Impacts on criteria pollutants will vary for systems depending on many factors including gas composition, end-use device geometry, operational parameters, presence of clean-up technologies, etc. One concern is increases in NO_x from the addition of hydrogen, although this could also reduce hydrocarbon and CO_2 emissions [386]. However, if device operation is controlled properly NO_x emissions could be maintained at equivalent levels [387,388] or even reduced due to leaner combustion [389]. Impacts may also be multi-faceted with regards to different pollutants. For example, adding hydrogen to natural gas had a range of impacts on NO_2 , NO , and N_2O emissions from an industrial boiler, including inverse relationships between species for some operating conditions [390]. These results highlight the complicated nature and lack of current understanding of emission impacts from end-use devices due to the blending of renewable fuels. Further studies are needed for stationary power generation technologies under a range of operating conditions and different renewable fuel blends. Studies should also be undertaken elucidating the AQ impacts from economy-wide scenarios of renewable gas blending in future years using atmospheric modeling. Results from such assessments can provide insights into end-use device management to minimize AQ degradation, potentially through policy mechanisms and other programs.

6. Discussion, analysis, and recommendations

Within this review we have demonstrated that natural gas generation and the natural gas system could play several important roles in supporting sustainable energy strategies over time that can achieve the GHG reductions and AQ improvements sought by society, most notably by maximizing the emission benefits of renewable resources. Natural gas generation can support transitions to renewable resources by (1) use in advanced conversion devices to provide complementary grid services efficiently and with very low emissions to maximize the benefits of intermittent renewable resources, and (2) natural gas generation and the existing natural gas system can support the use of renewable gaseous fuels with high energy and environmental benefits. This is because advanced conversion devices (including fuel cells [391]) can operate on natural gas and renewable gaseous fuels, including blends, with very low direct pollutant emissions and the existing natural gas system can support the production, storage, and distribution of renewable gaseous fuels. The ability of hydrogen to be produced via a range of pathways, including from multiple renewable feedstocks, and to be used by high efficiency and zero-emitting fuel cell devices in a diverse range of applications across all economic sectors (e.g., transportation, power generation, industry, the built environment) raises the possibility of energy systems with essentially produce negligible emissions of both GHG

and pollutants [392]. Advanced conversion technologies can thus provide renewable energy pathways that achieve very high GHG and AQ co-benefits [393]. Within this section, we propose a pathway forward for natural gas power generation to achieve AQ and GHG benefits within the broader context of sustainable energy systems and we describe required research objectives.

6.1. Towards a sustainable domestic gas system

Appropriate design, management and evolution of the natural gas system could produce a valuable resource for achieving a sustainable and 100% renewable energy conversion system including maximizing the GHG and AQ benefits of renewable power and fuels. The near- to mid-term use of natural gas in environmentally beneficial methods coupled with a managed evolution to renewable gaseous fuels could facilitate economically and technically feasible pathways to the long-term goal of a truly sustainable energy future characterized by fully renewable energy systems. The judicious use of natural gas to complement renewable intermittency, the increasing injection of renewable gaseous fuels into the current supply, and the evolution of infrastructure to reduce leakage and enable renewable fuel use (including hydrogen) throughout comprise a likely means of reducing the carbon intensity of gaseous fuels and a potential method of complete conversion of the natural gas system in the long-term. In Fig. 11, a potential evolution of gas resources, gas conversion strategies, and intermittent renewable complementary generation strategies are proposed to accomplish these aims.

It should be noted that electrification of end-uses in tandem with provision of renewable electricity should be pursued with priority due to the efficiency benefits relative to hydrogen/fuel cell strategies. Indeed, electrification in tandem with renewable power generation and other very low-carbon forms of energy is known to be an essential strategy in achieving deep carbon reductions and AQ improvements targeted for future sustainability [11,17–19,394]. However, a renewable gaseous fuel system could support large-scale

electrification in many ways, including providing a means of energy for end-uses that are difficult to electrify, e.g., aircraft, ocean going vessels, industrial applications. At the same time, the evolving natural gas infrastructure can provide services for large-scale and long-term storage, energy transmission amongst regions, and energy distribution to almost all end-uses throughout society. These services are valuable and cannot be simply replaced if the system is abandoned.

Nonetheless, a transition of the natural gas system of the type envisioned here is no simple matter and requires societal and technological advancements, innovation, and evolution. A significant set of research and development topics will have to be successfully addressed, and technologies and solutions must be developed to enable the transition as described in Fig. 11. Representative areas of research that are needed are presented in Table 17. The research areas are informed by the current review paper and are not comprehensive nor exhaustive, but rather illustrative of the broad set of needs.

In the near-term, natural gas supply will continue to predominate from fossil fuel pathways. Blends with fossil natural gas could feasibly reach 10–12% using existing infrastructure without modification, but will be technically limited as the initial supplies will largely arise from existing biogas resources (e.g., maximum potential for biogas has been estimated at 3 to 5% of national gas supply [362]). In the mid-term, the blending of renewable fuels up to or exceeding half of total supply should be pursued. This will require an amount of renewable gas production likely to represent a significant portion of total biogas resources and necessitate large-scale production of other renewable pathways including P2G and gasification of solid biomass. Therefore, the expansion of bulk gaseous renewable fuel production should receive a policy focus designed to reduce costs, improve technical feasibility, and quantify and achieve energy and environmental benefits in complete system applications. However, total demand for utility gas may be reduced through wide-spread electrification of end-use sectors thereby reducing the amount of renewable gas required for production. Research at this

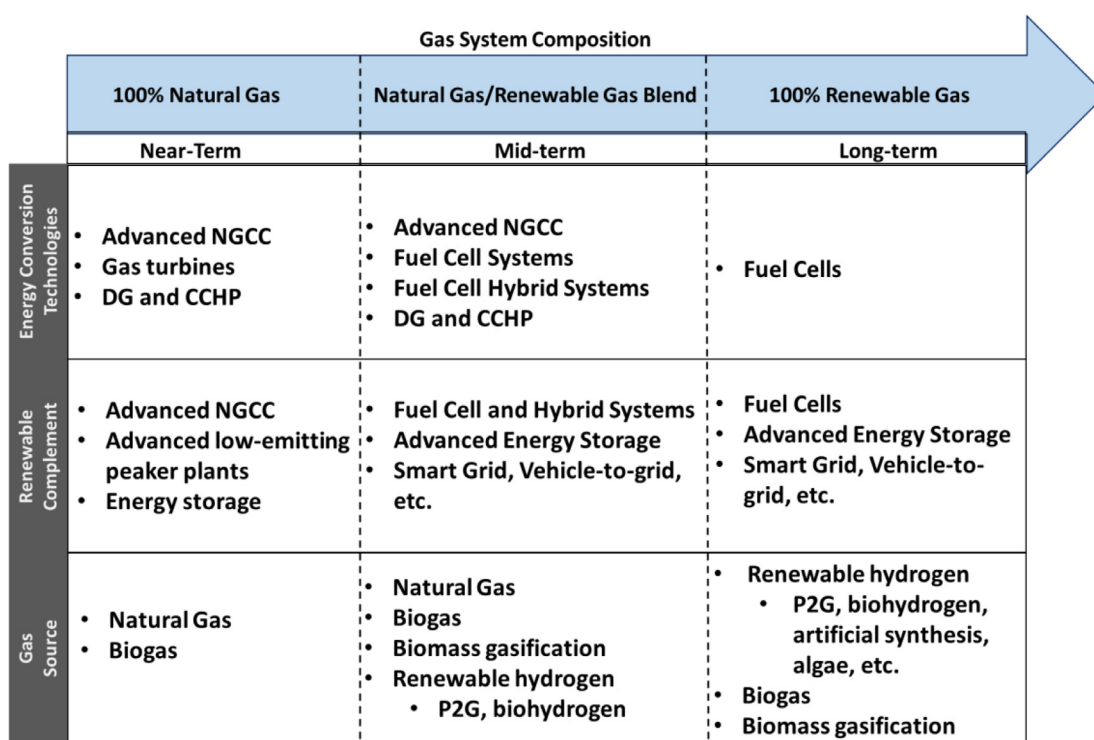


Fig. 11. Proposed steps towards transitioning from a fossil to completely renewable gaseous fuel system that minimizes GHG emissions and AQ impacts.

stage should focus on the economics and technical feasibility of advanced renewable gas production methods including artificial photosynthesis, nuclear generation methods, high temperature electrolysis, and others. The ultimate goal long-term will be 100% renewable gas that is produced, stored, transmitted, and distributed in the utility gas network. To accomplish this, bulk production of hydrogen will be required with the majority likely originating from P2G using the massive amount of peak renewable power that must be generated to meet all of societies energy demands. This may represent an important synergy with the electricity sector, as a goal for 100% renewable electricity will entail significant amounts of intermittent wind and solar that would otherwise be curtailed. Additional fuel production should be accomplished primarily through renewable pathways including artificial photosynthesis, solar water-splitting, etc.

Conversion methods should seek transitions away from devices utilizing combustion to electrochemical conversion such as that of fuel cells, fuel cell hybrid systems, and batteries. Commercially available stationary fuel cell systems and fuel cell hybrid systems should be prioritized over NGCC and other combustion technologies. However, it is likely that NGCC and other clean natural gas power plants will continue to make up some portion of generation in at least the near- to mid-term. Major efforts should continue to identify and limit leakage from the natural gas system, as well as to identify potential impacts of renewable fuel blending on leakage rates. The region of deployment must be considered in technology choice. Regions with current or planned coal generation will benefit from the use of even conventional NGCC, while regions already utilizing significant amounts of natural gas generation, e.g., California, should seek transitions to advanced devices including fuel cells. Also, impacts of renewable fuel blends on the performance and emissions from end-use devices should be pursued. An additional area of research should focus on identifying and prioritizing the best uses of renewable gas in the near-term

due to limited supply and varying opportunities for electrification in end-use sectors.

Complementary generation for renewable balancing should focus on utilizing advanced NGCC in the near-term, as these are commercially available, have favorable economics, and reasonably low emissions relative to other fossil options. Additionally, advanced low-emitting peaker plants exist that can significantly reduce emissions from current peaking generation. In the mid- to long-term, complementary generation for renewable resources should be accomplished via advanced energy storage to the maximum possible extent, with fuel cells and fuel cell hybrid systems providing the remainder. Additionally, Smart grid and related strategies should again be pursued with high priority due to the synergistic and beneficial interactions with integrating higher levels of renewable generation, particularly those with intermittencies. A research focus is needed for developing advanced complementary strategies with low- to zero-emissions including fuel cell systems such as those described in [38], P2G systems, advanced energy storage that can technically and economically provide terawatt-hour-scale storage, and advancement of other load management services including vehicle-to-grid, demand response, and others.

Due to the inherent energy and environmental benefits that are possible, use of biogas resources for energy (rather than no collection or flaring) should be targeted with priority [395]. However, as discussed in Section 4.4, AQ emissions from current conversion methods can represent a major barrier to enhanced deployment levels. For example, while cost effective, reciprocating engines have difficulty meeting stringent AQ emissions permitting requirements, which can prevent new projects or even limit the operation of existing systems [396]. In the near-term then, gas clean-up and injection into the existing gas grid should be pursued as a means of immediately reducing the carbon intensity of the gas system while avoiding permitting challenges.

Table 17

Representative areas of research to support GHG and AQ Co-benefits of a 100% renewable gas system.

Natural Gas System	
• Identification of methane emissions sources and potential mitigation measures in the existing natural gas system • Impacts of renewable fuel blending at high levels in the natural gas system, e.g., emission rates, materials impacts, safety, emissions and effects on end-use devices • Pipeline and other infrastructure impacts of renewable fuels and the management and replacement schedules that are required	Representative Research Topics: leakage identification and quantification; leakage mitigation technologies; natural gas infrastructure materials science research for long-life renewable gas compatibility; combustion and electrochemical conversion of natural gas/renewable gas mixtures and pure renewable gas; strategies for reducing emissions from conversion technologies; infrastructure (pipes, fittings, regulators, compressors, etc.) renewable gas compatibility; infrastructure degradation understanding; degradation mitigation strategies; high efficiency compression (e.g., electrochemical compression); leak detection (e.g., odorants, sensors) science and engineering; pipeline & infrastructure conversion/modification approaches for gradually accommodating more renewable fuels
Conversion Technologies	
• Barriers to the implementation and operation of zero and ultra-low emissions renewable gas conversion technologies (e.g., biogas/natural gas mixture combustion impacts) • Technological development and commercial maturity of fuel cell systems and hybrid fuel cell heat engine systems (e.g., dynamic flexibility of fuel cell and heat engine systems to complement renewable intermittency)	Representative Research Topics: lower pollutant emissions of natural gas combustion; enable renewable gas and mixed renewable/natural gas combustion with low emissions; enable transitions of natural gas end-uses to increasingly use renewable gas (in mixtures) and ultimately pure renewable gas; advance and enable highly dynamic dispatch of high temperature fuel cell systems (SOFC, MCFC) and other controllable low emissions power generators; biomass and biogas compatibility of fuel cell systems; integrated ultra-high efficiency hybrid SOFC and MCFC gas turbine (GT) systems; integrated hybrid SOFC and MCFC chiller systems; electrochemical polygeneration of hydrogen, heat, power, cooling;
Renewable Fuel Production	
• Optimal uses and pathways for biogas resources, e.g., transportation vs. power generation • Technical and economic feasibility of large-scale P2G systems integration at the regional and national scale • Technological development of advanced renewable fuel conversion methods	Representative Research Topics: systems engineering and utility network analyses for integrated renewable electricity, renewable gas, and renewable transportation pathways; lower cost alkaline and proton exchange membrane electrolysis (e.g., noble metal use reduction, corrosion suppression, smaller balance of plant); develop higher efficiency solid oxide electrolysis (SOE) systems; develop molten carbonate electrolysis (MCE) systems; develop reversible SOE and MCE fuel cell systems; SOE and MCE degradation mechanisms; dynamic operation and thermal management of SOE and MCE systems; co-electrolysis of CO₂ and steam to produce renewable methane; artificial photosynthesis; heat-based or heat assisted (e.g., solar thermal, nuclear) hydrogen production; novel rate structures and policies for access to and use of otherwise curtailed renewable electricity

Barriers to the deployment of advanced conversion technologies including fuel cells and micro-turbines should be addressed in the near- to mid-term, as the use of distributed technologies with very low emissions to convert biomass and biogas fuels on-site represents a key opportunity to maximize GHG and AQ benefits of renewable resources [207].

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