Review article

Geoenergy

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The future of geoenergy – a perspective

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Abstract: Energy from Earth resources (geoenergy) in the form of coal, oil and gas has fuelled the global society since the Industrial Revolution began. Amongst the consequences of fuelling society and associated population growth, is climate change, driven by the emission of greenhouse gases liberated through unabated combustion of fossil fuels.

There is much more to Earth energy systems, however, than just coal oil and gas. The Earth contains, in human terms, an unlimited supply of accessible heat and pressure (differences), as well as copious quantities of storage space, non-hydrocarbon gases and valuable solutes. These resources can be targeted to provide sustainable energy sources with low to zero carbon footprints.

This report does not contain any new radical technologies that will deliver energy free from all environmental impacts but it does show that, when considering geoenergy, society needs to look at the whole system, which combines chemical, thermal, potential, kinetic, gravitational and other energy forms that could be used from individual developments to minimize waste, maximize efficiency and reduce unwanted impacts.

We demonstrate that geoenergy will continue to play a key role in decarbonized energy systems for centuries to come.

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The aim of this work is to appraise Earth-energy resources without it 'costing the Earth'; minimizing the impact on the atmosphere, hydrosphere, biosphere and lithosphere. Energy resources are examined, those for which extraction will be sustainable and use of which will not lead to the large-scale release of greenhouse gases. We are UK-based and, hence, the energy systems examined are dominantly those of the UK. However, whilst the UK is a geographical island, or rather many islands, it has not been isolated in energy terms since the early days of the Industrial Revolution. It has, and continues to be, an exporter and simultaneous importer of energy. Energy imports are currently larger than exports. The reverse was true in the last century. Before that, the UK was self-sufficient when 'coal was king' in the nineteenth century and earlier (Paxman 2021), only becoming a significant importer of liquid fuels after World War I (Warr *et al.* 2008). This account, therefore, includes reference to other parts of the world.

For many people, the term 'Earth-energy resource' will be interpreted as nebulous and a form of greenwashing (a cover up for the frequently derided fossil fuel industries, coal, oil and gas). It should always be recognized, though, that it has been the availability of (relatively) cheap and plentiful energy produced from the combustion of these three materials has though helped 80% of a growing global population escape abject poverty (Rosling *et al.* 2018). This fact is often forgotten while only the ongoing legacy of the fossil fuel industries is highlighted (Gao *et al.* 2021; Q. Li *et al.* 2021) emission of greenhouse gases; oil leaks and spills; collapsing coal slag heaps; human-induced seismicity; and more. In contrast, the public image of an offshore wind farm is typically better – gently turning turbines generating clean, green (low-carbon) electricity, dispatched to shore, and ready to power our lives and our futures. But this narrative is far too simplistic. The Earth still needs to supply the materials for every wind turbine, every solar panel and all the transmission systems, with this also being true for any other renewable energy technology. Whilst operations may well be close to carbon neutral, the full life-cycle carbon costs can remain high (Campos-Guzmán *et al.* 2019). There is no corresponding positive story from the geoenergy lobby. Indeed, there is little by way of a geoenergy lobby and yet the Earth can and does supply low- and zero-carbon energy and energy materials, and could do so much more. In this paper it is the 'more' that is examined; geothermal, geokinetic and geopotential energy, together with energy storage and energy-carrying geofluids. And so, the aim is to answer, what is our geoenergy future?

Geoenergy past

It is worth examining why fossil fuels emerged as the key primary energy source around the globe. The use of coal initially, followed by oil and natural gas, is what drove the Industrial Revolution in both the literal and metaphorical senses. The driver to first exploit coal in large quantities was not the inventive genius of eighteenth and nineteenth century industrialists, scientists or market capitalists but, rather, fuel poverty in pre-industrial England. Coal had been known for centuries, possibly millennia, as rock that would burn. Oil too had been produced from natural seeps well before the self-proclaimed Colonel Drake drilled a well at Titusville Pennsylvania in summer 1859 (Dickey 1959), such as in the form of Trinidadian tar for caulking warships (Spielmann 1938) or possibly a key ingredient of Greek Fire (Haldon *et al.* 2006) and other ancient incendiary missiles. Gas wells have also been drilled in China for centuries to provide heat for drying salt pans (Vogel 1993). However, these and other older instances of fossil fuel use were but sideshows, because the main fuels of those times then were organic matter, wood and dried dung later, with the later use of whale oil or animal fats for lighting. By the end of the seventeenth century, many parts of England were suffering an acute shortage of wood, the land shorn of trees, meaning food could not be cooked and many were starving (Nef 1977). Mining for coal had been disfavoured (Nef 1977) but needs must, and coal production increased to meet a growing demand for energy. It proved to be a versatile fuel with a far greater energy density than wood, meaning it could be transported, stored and used for energy in more practical ways. Steam engines, invented to pump water from mines, found alternative uses – the Industrial Revolution had begun. Britain was the first to substantially exploit energy-dense coal. In particular, coal mined in NE England (the Durham and Northumberland coalfields: Paxman 2021) was conveyed downriver from upland coal mines to coastal ports and shipped into London. London grew to be the first global city (population >1 million) and it was fuelled by coal. Paradoxically, in its time coal was also considered to be the modern and clean alternative to dirty biofuels in an age where domestic lighting was still often provided by burning tallow or the oil of sperm whales.

Oil came of age as the twentieth century began. It had been growing in importance in the latter half of the nineteenth century but it was a surge in demand that came in the wake of the invention of the internal combustion engine, coupled with the discovery of the world's first giant oilfield at Masjid-i-Suleiman in Persia (now Iran), which changed the world forever (Owen 1975). Karl Benz sold his first car in 1895, the Wright brothers flew at Kittyhawk in 1904 and naval shipping switched from coal to fuel oil as World War I ended.

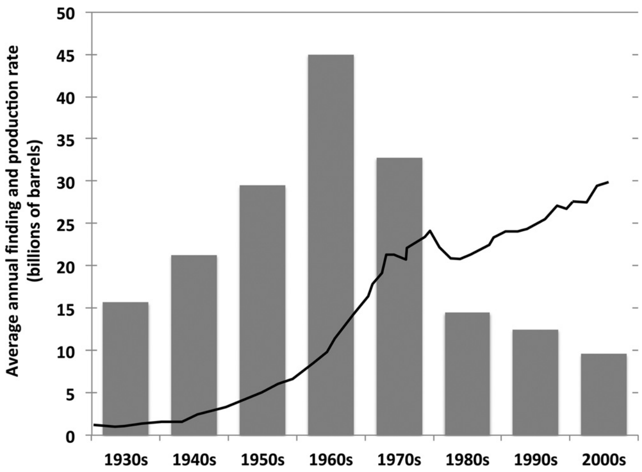

Fig. 1. Comparison of oil findings and consumption rates. Source: from Gluyas and Swarbrick (2021).

Geoenergy present

The UK faded as the first global giant of coal production but the USA continued and was soon joined by Australia, South Africa, India and subsequently China as the world's mega-producers. Global coal production continues unabated both in terms of volume and in terms of not capturing or storing the derived carbon dioxide when it is combusted.

In the earliest years of the twentieth century, California (USA) produced the most oil in the USA and many other areas in the Lower 48 (states) were quick to follow, most notably Texas, which is now considered by many as the home of the oil industry. Oil production from Texas faded by the mid-twentieth century but its role in a geoenergy future was to become important again in the 1970s in response to the first oil crisis (reported below).

Following the discovery of the first giant oilfield in Persia (now Iran) by D'arcy Oil (now bp), the race was on to find more in the Middle East, especially Saudi Arabia, Iran, Iraq, Kuwait and other known oil provinces such as Latin America (Mexico and Venezuela). Technology too was advancing, and seismic acquisition and interpretation of the data became the key tool for identifying prospective areas in which to drill. By the mid-twentieth century, the volume of oil discovered each year was massively more than that being used. The peak years for oil discovery were the 1960s and the rate of discovery has since declined, with 2015 marking the first year in which no new giant discoveries (>500 million barrels recoverable) were added. Today, the production rate of oil significantly outstrips its finding rate (Fig. 1), meaning that the oil age is of limited duration, even if we ignore the negative impact of petroleum consumption on the climate.

A group of nations that both produced and exported oil (OPEC) was formed in 1960, in part to better control supply and reduce the dominance of developed nations in controlling both the price and supply of oil. The first oil crisis occurred in 1973 when OPEC restricted supply. Aside from the obvious impact on oil-consuming nations, there became a significant push to improve recovery from existing fields. Large-scale application of enhanced oil recovery (EOR) was first practised in Texas with anthropogenic carbon dioxide being injected into oilfields to improve oil recovery, this was a technique pioneered in Hungary in the 1950s (Remenyi *et al.* 1995). There are now some 100 plus CO_2-EOR projects running in Texas, which collectively have added an extra billion barrels of production. Unfortunately, from a climate perspective, only a small proportion of the injected CO_2 is from anthropogenic sources; most instead comes from naturally trapped CO_2 accumulations (Kuuskraa *et al*. 2013).

Natural gas exploitation at a large scale lagged behind oil because of the relative difficulty in transporting it to locations other than where pipelines could be constructed linking field(s) with customers. Some countries already had manufactured 'town' gas (syngas from coal) production and distribution networks. In the UK, for example, almost every town had a gas works and local distribution network by the beginning of the twentieth century. Yet after the discovery of North Sea gas, beginning in 1965 with the West Sole Field, the then government determined that town gas would be phased out (largely to improve air quality in cities) and it was displaced by natural gas from the Southern North Sea. This necessitated construction of pipelines from the fields to shore and the creation of a national (gas) grid onshore. Every gas boiler also had to be converted from burning town gas (a mix of methane, hydrogen, carbon dioxide and carbon monoxide) to North Sea gas (essentially pure methane spiked with very smelly mercaptans for safety reasons).

Whilst natural gas became the mainstay of domestic heating and power production for the UK, in many areas of the world it was considered without value. In oil-rich Venezuela, discovered gas fields were left undeveloped and in oilfields the methane coproduced with oil was simply flared or even vented (Anon. 2004). Most gas is transported via intracontinental pipelines (in 2021, 643 Bm^3: bp 2022) and less by tanker (in 2021, 398 Bm^3: bp 2022). This has led to a partially segmented global gas market with large variations in gas price across the world. It was not until gas liquefaction and, hence, transportation by supertanker became technically and commercially viable did natural gas become a semi-global commodity with intercontinental markets formed. Qatar was able to develop North Dome, the world's largest gas field as liquified natural gas (LNG), with the LNG process also unlocking Algeria's and Australia's NW shelf gas deposits to markets in Europe, Japan and elsewhere. Pipelines too were built over long distances, linking land-locked circum-Caspian and Siberian gas into Europe and leading to a dependency of Europe on imported gas, much of which is from Russia, which by the 2020s proved fateful following Russia's invasion of Ukraine. Gas supply became restricted and this led to significantly increased prices.

The advent of large-scale LNG processing also caused a permanent market change for one other commodity: helium. The second most abundant element in the universe, helium is rare on Earth. The first substantial discovery of helium was in 1903 at Dexter, Kansas, a gas well that became famous as the gas that would not burn, it being largely nitrogen. This curiosity was subsequently shown to be a gas containing 1.84% helium. Helium became a strategic commodity in the World War I when it was wrongly believed Germany was sourcing helium rather than hydrogen to fill its military blimps and balloons. In the wake of the war, both the USA and the USSR screened existing gas wells for helium (Gluyas 2019*a*). The investigations in the USA showed that many of the more than 3000 wells sampled contained small quantities of helium (Anderson and Hinson 1951; Boone 1958). As little as 0.3% helium by volume in a well test was considered economically viable for its extraction. Much helium so extracted became part of the US strategic reserve and for the next 100 years the USA has had a near-monopoly on the helium supply. This changed with the development of major LNG systems. Algeria's Hassi R'Mel Field contains around 0.19% helium and Qatar's North Dome 0.04%. Together, Algeria and Qatar now supply about half of the world's helium production (Fig. 2). Despite the growth in helium supply, it commonly fails to meet demand (Kramer 2023). Helium has a wide range and growing number of applications, especially in the manufacture of fibre optics and computer chips, both of which need to be built in inert, helium-filled, positive-pressure, environments. Medical cryogenic systems also demand liquid helium for cooling magnets and should fusion energy become commercial, it too will require copious quantities of helium as a coolant (Bradshaw and Hamacher 2013). A low-carbon future, significantly dependent upon the availability of helium (Olafsdottir and Sverdrup 2020), presents society with an oxymoron because it is extracted from gas wells and LNG processing in tiny quantities relative to the methane and other hydrocarbons produced. Indeed, today's helium industry has a huge collateral carbon footprint from production alone of about 320 Mt of carbon dioxide, which is equivalent to 95% of that for the whole of the UK, 335 Mt, in 2021 (EDGAR 2022) (see Appendix A).

Geoenergy future

Setting aside petroleum production or coal mining, what is the future for geoenergy? The Earth's crust can still deliver a range of finite but large-scale commodities needed, as well as sustainable energy streams and space for energy storage. Here we will not consider the mining of solids for energy materials such as rare earth elements or critical metals but will examine the abstraction of geofluids, including those that have commonly been considered as unwanted co-products of petroleum production.

Although the emphasis of this work is on non-fossil fuel sustainable geoenergy systems, we cannot ignore that we live in a world and a nation dominated by petroleum. Moreover, thanks to the abundance of oil and gas on the UK Continental Shelf, the nation became a petro-economy for around 30 years from when North Sea gas (1965) and oil (1975) production began (Christophers 2020). Although the UK's petroleum provinces are highly mature, only about 43% of oil from the developed oilfields has been recovered on average; the corresponding figure for gas is about 70–75% (OGA 2017) (Fig. 3). The production of both oil and gas will continue for decades but these remaining producing fields can be partially or totally decarbonized using what we might call geoenergy processes. These too we examine.

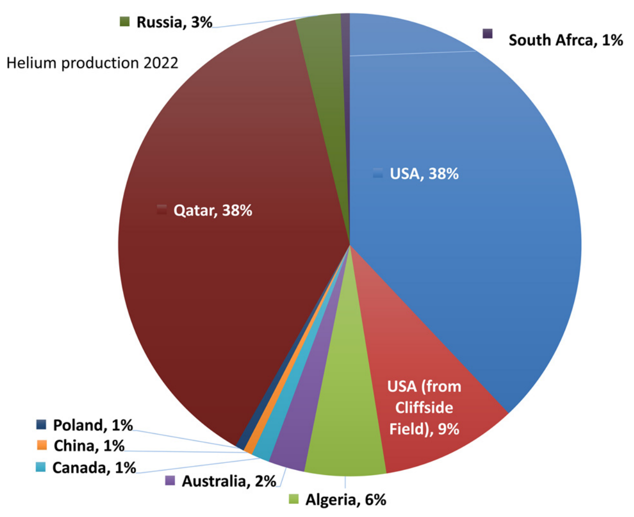

Fig. 2. Global helium production 2022, equalling 160 Mm^3. Source: data from USGS (2023).

Hydrogen, helium and lithium

It is with helium that we will begin to examine coproduced fluids. Although not an 'energy' element, helium is critical to several low-carbon and energy transition technologies (Gluyas 2019*b*). The accidental discovery of helium at Dexter, Kansas in 1903 set in motion an industry based entirely on serendipitous helium discoveries. Until 2016 no one had developed and tested a helium exploration strategy. There were no helium play-fairway maps and no helium source risk statistics, and yet every few years another helium supply crisis would emerge. Danabalan (2017) and Danabalan *et al.* (2022) tell the story of a systematic evaluation of helium sourcing from granitic (Archean basement) rock rich in thorium and uranium to helium migration from source to carrier beds, and from carrier beds to sealed trapping structures. Danabalan *et al.* (2016) provided the first report of a new helium province in a century and the only one from which hydrocarbons are absent – Tanzania's Lake Rukwa area, which contains numerous cold gas seeps of nitrogen with subordinate helium. Typically, the helium content is 5–10%, a helium concentration some 10–100 times greater than currently commercially productive sites in the USA, Algeria and Qatar. The historical coincidence of hydrocarbons and helium is largely that, coincidence. The work of Danabalan and others demonstrated that helium and hydrocarbon systems have fundamentally different origins but can share pore space within reservoir systems. Thus, from a helium perspective, much of the world remains unexplored and with the basic requirements of ancient granitic crust with a cover sequence containing reservoir and high-quality seal combinations, it should be possible to identify prospective areas.

Hydrogen is the most abundant element in the universe but, unlike the rare helium, it is present in huge quantities here on Earth. There are two atoms of hydrogen in every water molecule and upwards of four atoms in every hydrocarbon molecule. If hydrogen is required, then it can be obtained from either hydrocarbons or water. Combusted hydrogen yields only water vapour and no carbon dioxide, and as such there is a growing desire to rebase society on hydrogen instead of hydrocarbons (petroleum). Therein lies a

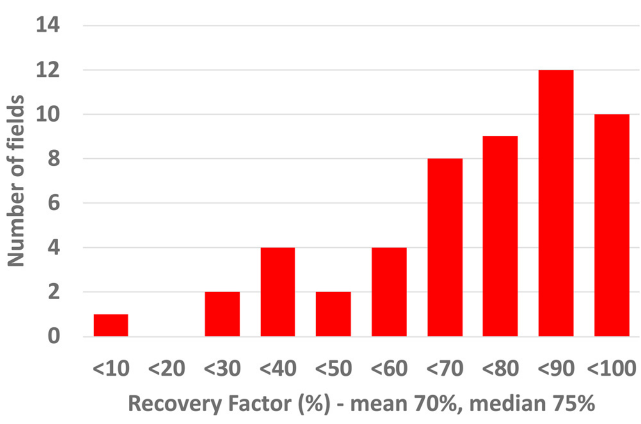

Fig. 3. Gas recovery factor, UK gas offshore gas fields. Source: compiled from data in Gluyas and Hichens (2003) and Goffey and Gluyas (2020).

problem, since, although plentiful, the separation and production of hydrogen is currently energy intensive. About 99.5% of 95 Mt of hydrogen produced in 2022 (IEA 2023*a*) was from natural gas via steam methane reforming, coal via gasification and as a byproduct of oil refining, with only 0.5% from electrolysis. Moreover, only 1% of hydrogen produced from fossil fuels includes carbon capture and storage (Zapantis 2021). Thus, 99% of the co-produced carbon dioxide is released into the atmosphere with 7 t of carbon dioxide liberated for every 1 t of hydrogen produced (IEA 2023*a*, *b*). As it stands, the hydrogen industry has a significant carbon footprint and substantially higher costs, and is less energy efficient than using methane for heat production directly. The emissions profile of hydrogen production can be reduced with carbon capture and storage but the energy penalty of doing so is between about 10 and 14%, and the efficiency of capture is around 90% (Zheng *et al.* 2023).

Because hydrogen has not until now been required in massive quantities and because capture of waste carbon dioxide from its manufacture has not been a concern, few have considered what the Earth has to offer in terms of native, molecular hydrogen. That is changing. Zgonnik (2020) published a comprehensive inventory of natural hydrogen occurrences. There are hundreds of them (Zgonnik 2020) and their locations are clearly spatially biased to locations with gas seeps or flows that have been tested for hydrogen. In that regard, the former Soviet Union and its then allies are very rich in hydrogen occurrences, and the USA apparently very poor. When, after World War I, the Soviets and Americans both searched for helium, the Soviets generally recorded the occurrence of hydrogen but the Americans did not.

The planned start-up of natural hydrogen production in Nebraska in 2024 could be the beginning of a significant hydrogen exploration industry (Ball and Czado 2022). South Australia too has licensed acreage for hydrogen production. There is evidence from wells drilled 90 years ago, on Kangaroo Island offshore Adelaide, of hydrogen-rich gases in the subsurface (Rezaee 2021). Mali was the first country to commercialize hydrogen production (Prinzhofer *et al.* 2018). A well drilled for water at Bourakebougou, Mali in 1987 instead found gas containing 96% hydrogen. Moreover, some of the best known ‘perpetual fires’ – burning gas seeps – are hydrogen, including the famous one at Chimera in Turkey (Hosgörmez 2007).

The Earth produces hydrogen in a variety of biological and abiotic ways. The two most significant geological processes are from the oxidation of iron minerals during serpentinization and ophiolite formation, and via radiolysis of water by the same radioactive decay processes that produce helium. The hydrogen produced by both processes is estimated at *c.* 0.1–0.5 Mt a^{-1} in the Precambrian continental lithosphere (Sherwood Lollar *et al.* 2014). Using the hydrogen production rate range calculated by Sherwood Lollar *et al.* (2014), in the last 1 Gyr the Earth’s Precambrian lithosphere has produced 0.36×10^{20} –2.27×10^{20} mol of hydrogen. This is sufficient hydrogen to displace the whole of the petroleum industry for 18–112 kyr (160 764 TWh global energy use in 2022 from Our World in Data 2024). However, most of that hydrogen will have been lost, especially given how reactive and, hence, bioavailable hydrogen is. It is too early to know whether there is a significant natural hydrogen resource but what is clear is that conventional petroleum provinces are not the place to look for it. There may well be an overlap between (natural) gas areas and hydrogen areas but not so for liquid petroleum, which will react with hydrogen to saturate undersaturated hydrocarbons.

There are other subsurface fluids that are gases at standard temperature and pressure; the most common are nitrogen, carbon dioxide and hydrogen sulfide. Such gases do not have value as sources of energy via combustion and do not share the unique physical properties of helium. Nonetheless, nitrogen is not a greenhouse gas and therefore it may be possible to exploit its geokinetic and geothermal energy potential. These properties are examined later in this paper.

The remaining abundant geofluid, indeed the most abundant geofluid, is saline water (brine). The thermal properties of water are key to its value in geothermal energy systems but here let us first examine solutes present within subsurface brines. The compositions of subsurface brines (formation waters) are very varied (Hardie and Eugster 1970; Warren and Smalley 1994) and some contain high concentrations of lithium, a key element for the energy transition.

The importance of lithium in the global economy has grown substantially in the past two decades (Ambrose and Kendall 2020) (Fig. 4a, b) because it is a key component in rechargeable batteries and thus the electric vehicle industry. A battery for a typical family electric car contains about 8 kg of lithium carbonate. Traditionally, lithium has been obtained from processing minerals such as spodumene and lepidolite or pumping brine from salars (salt pan) of the Andes (Argentina, Bolivia and Chile). Both industrial processes have substantial environmental impacts (Kaunda 2020). However, geothermal brines and unwanted but coproduced oilfield brines can also be rich in lithium (Fig. 5), and with recently developed direct lithium-extraction techniques using ion exchange processes (Stringfellow and Dobson 2021) the lithium can be won without concomitant waste products. Pilot projects include Qinghai Salt Lake and Qarhan Salt Lake in China, Salton Sea in the USA, and two projects both in the UK that will combine geothermal and lithium production in Cornwall and Weardale (County Durham).

In addition to lithium there are a few other energy-linked elements that could be extracted from some subsurface brines including zinc and boron (Bloomquist 2006).

Geothermal energy

The Earth is an enormous heat engine. It has remained hot since its formation 4.53 Gyr ago and will still be hot when the Sun switches from consuming hydrogen to helium, grows and eventually destroys life on Earth (Schröder and Smith 2008). Despite the availability of the Earth to deliver sustainable heat to humanity it is little exploited, with only 0.5% of global energy (electricity generation and heating) use coming from geothermal sources (IRENA 2023). The Earth’s heat is a combination of primordial, from the gravity-induced formation of the planet and that generated from the decay of radionuclides such as potassium, thorium and uranium. Natural hot springs have been exploited by animals including humans and plants but it was not until 1904 at Larderello in Italy that geothermal energy was harnessed to produce electricity. In 2023 (Table 1), the biggest users of electricity generated using geothermal heat were the people of California, USA (Sanyal and Enedy 2011; Richter 2023), whilst China had developed the most direct use geothermal heat systems (Table 1; IRENA 2023). Iceland is the nation with the largest proportion of its total energy demand coming from geothermal sources at 65%, with a further 20% from hydroelectric schemes (Government of Iceland n.d.).

In spite of these examples, and its near-universal geographical availability, geothermal has not been widely harnessed and has been slow to develop as a major energy source for two main reasons:

- Cost – more than 80% of the cost of a geothermal development can be associated with well construction (i.e. drilling) costs (Augustine *et al.* 2006).
- The materiality of project relative petroleum development costs – the energy density of oil is about 44 MJ kg^{-1} and that of natural gas 55 MJ kg^{-1}. Cooling 1 kg water by 30°C liberates 0.126 MJ kg^{-1}.

It is important to recognize that these reasons are not technical, as these would be, for example, in the case for deploying nuclear

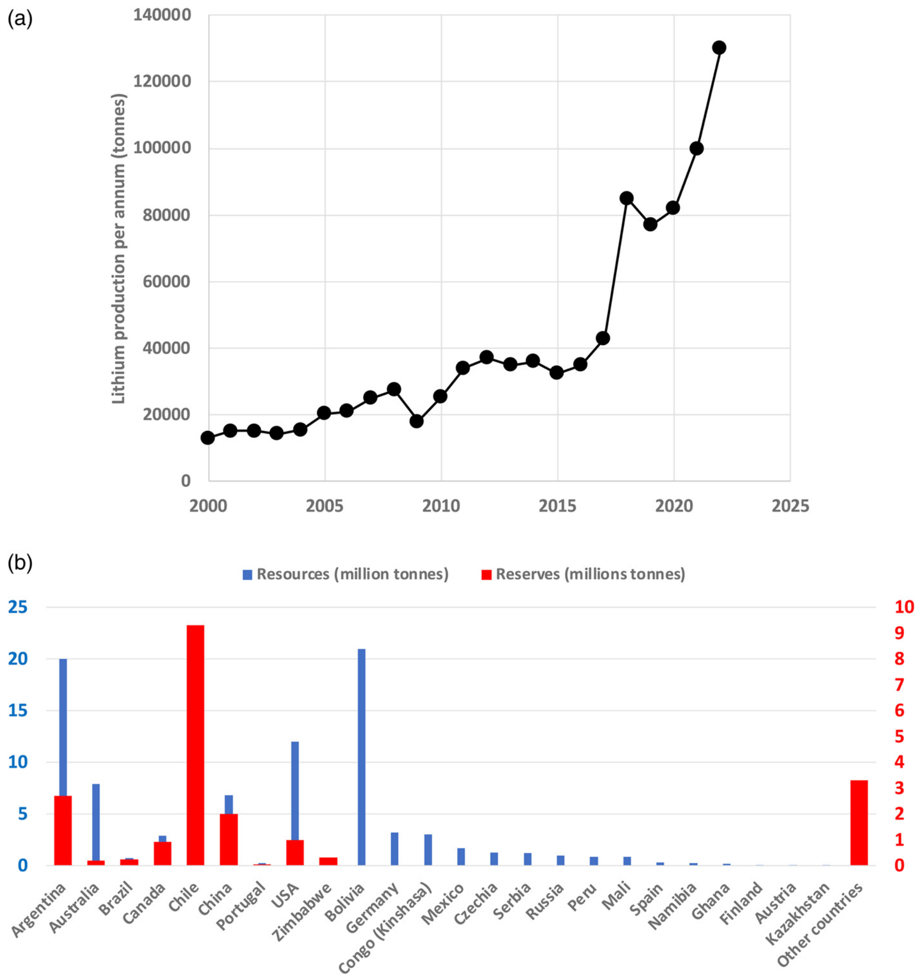

Fig. 4. (**a**) Global production profile for helium. (**b**) Global lithium resource and reserves by country. Source: compiled from USGS (n.d.).

fusion (currently). The technology to harness geothermal certainly exists and the resource is also undoubtedly big enough. The reasons for the lack of uptake of geothermal energy might therefore appear strange but are usually cited or dismissed as ‘techno-economic’; however, this is an economic choice to use alternatives in preference to geothermal. The typical argument is that the capital intensity (the cost) and return on investment (the materiality) upon which any new energy project is assessed can be poor for geothermal in an economic environment where ‘cheaper’ alternatives exist. Being somewhat biased, though, we find this argument weak because we do not believe it is often rigorously applied to other sources of energy. If the full life-cycle economic and environmental costs of unabated fossil fuel usage, nuclear and other types of renewables were also considered (Campos-Guzmán *et al.* 2019) and properly compared with geothermal they may no longer appear so cheap. For example, a housing developer will consider only the connection costs for gas and electricity installation compared with geothermal energy in which the whole infrastructure cost would commonly be assessed. In addition, we have been asked to provide the costs for backup to geothermal energy systems should they fail. This is not something a developer would request prior to installation of electricity or gas. Energy security is also a political issue, and resources are often developed or encouraged for strategic and political reasons rather than just pure economics. If the political will existed, the use of geothermal could be massively expanded, and with its expansion, like wind- and solar-derived power, the cost would also come down as the technological and manufacturing bases improved.

Because of geothermal energy’s techno-economic challenges, current areas of research are specifically targeting both the cost and the materiality challenges to help it ‘break through’ the economic hurdles and therefore encourage the political recognition of

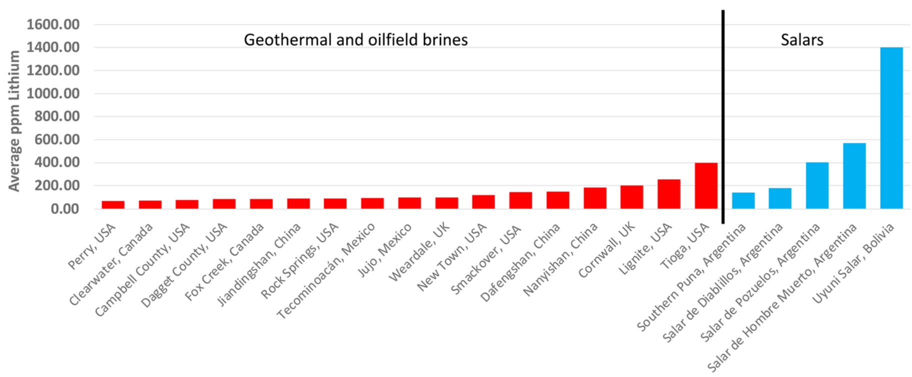

Fig. 5. Lithium content of geothermal brines and co-produced brines from petroleum fields compared with that in salars (salt pan). Source: Collins (1976), Manning *et al.* (2007), Birkle *et al.* (2009), Mernagh *et al.* (2013), Daitch (2018), Lopez Steinmetz *et al.* (2020), Wrathall (2020), J. Li *et al.* (2021) and E3 Lithium (2023).

Table 1. Power production from geothermal energy – global league table 2022 (Richter 2023) and installed geothermal heating and cooling in 2020 (IRENA 2023)

Country	Installed capacity – electricity (MW_e)	Installed capacity – heating and cooling (MW_{th})
USA	3794	20 700
Indonesia	2356	
Philippines	1935	
Turkey	1682	3500
New Zealand	1037	
Mexico	963	
Kenya	944	
Italy	944	
Iceland	754	2400
Japan	621	2500
China		40 600
Sweden		6700
Germany		4800
France		2600
Finland		2300
Switzerland		2200
Other	1097	Not recorded

geothermal as an economic, stable, reliable and available source of renewable energy for all nations. In part, a breakthrough has been achieved for low-enthalpy district heating systems linked to both extraction of heat and storage of heat in abandoned and flooded mines. Operational systems exist in The Netherlands (Verhoeven *et al.* 2014), Germany (Hahn 2022) and two locations in Gateshead, UK (Adams 2023).

Recent start-up companies are researching, developing and challenging the paradigms associated with geothermal development cost. New and experimental drilling technology using microwave and acoustic technologies seek to dramatically increase rates of penetration for drilling whilst simultaneously reducing the cost per metre drilled (Oglesby *et al.* 2014; Song *et al.* 2023). If the cost could be reduced, the techno-economic argument might well reach a tipping point in geothermal energy's favour.

The lack of a well-developed supply chain for geothermal energy development is also often perceived as a current hurdle because of the belief that well costs will be high. This is changing rapidly, however, and temperatures useful enough for direct heating purposes can be reached at relatively modest depths in much of the UK with large geotechnical drilling rigs.

Despite the slow uptake of geothermal energy, the potential is enormous and much more evenly spread around the globe than fossil fuels. Because everywhere on Earth can access geothermal energy and because heat does not travel well, there can be no geothermal equivalent of the 1973 oil crisis. For example, it would be possible to develop geothermal energy in the Niger Delta region even though the geothermal gradient is lower than 10°C km^{-1} in the central area of the delta due to a high accumulation rate of cold sediments (Akpabio *et al.* 2003). Admittedly, any wells in the Niger Delta would need to be drilled much deeper than any in Iceland, Italy, Indonesia or similar areas of high heat flow in order to target similar temperatures.

Average (mean) geothermal gradients are typically *c.* 30°C km^{-1}. The UK as a typical average geothermal area could still supply all its heating (and cooling) needs for at least 100 years if it chose to exploit deep saline aquifers, radiothermal granites, and abandoned and flooded mines (Gluyas *et al.* 2018*a*); yet, it has little by way of a historical geothermal industry. A single geothermal well in Southampton was until very recently the only operating geothermal system in the UK. As such, opportunities to develop the UK's geothermal potential are viewed by many as untested and, hence, risky. This response could be considered bizarre if one recognizes that industry has drilled many more than 10 000 'geothermal wells' on the UK Continental Shelf as oil and gas exploration, appraisal and development wells (OGA 2018). Of course, the petroleum has been produced and used from some these wells but the co-produced and commonly boiling brine is wasted. The hottest of these wells at a depth of >5 km in the Central North Sea have bottom hole temperatures in excess of 200°C. About 70% of the exploration wells drilled failed to find petroleum but they did find hot water. Referred to as 'dry' by the petroleum industry, all such wells are plugged (with cement) and abandoned. Auld *et al.* (2014) demonstrated that co-produced water from larger fields such as Ninian and Statfjord could deliver tens of megawatts of power (electricity). This has not been realized but still could be for producing fields. Auld *et al.* (2014) proposed using organic Rankine cycle engines to convert the heat to power but it is possible that large-scale thermoelectric devices could be developed to do the same thing with minimal interventions required to the production facilities on the field. Wu *et al.* (2022) described photo-thermal-electric systems that might be so developed.

Brine is not the only fluid that could be used to extract heat from the Earth. This could also be done using dense-phase carbon dioxide in a process known as CO_2 plume geothermal (CPG: Fleming *et al.* 2022). As yet there are no operational systems but there are a number of properties of dense-phase CO_2 that are important despite the heat capacity of CO_2 being much lower than that of water. Dense-phase CO_2 has the viscosity of a gas, meaning that it will easily flow through the matrix porosity of a reservoir and gather heat. It also has a density that varies widely as a function of pressure and temperature around its critical point. This means that for a good quality reservoir with a mean permeability of *c.* 100 mD or better and a temperature of 100°C or above, it should be possible to establish open-cycle thermosiphons between paired injection and production wells (Adams *et al.* 2014) (Fig. 6). The absence of a requirement for a parasitic load to pump the CO_2 into the ground and using a CO_2 expansion turbine to extract energy, it would be possible to produce and dispatch electricity (Adams *et al.* 2015). If CPG can be proven to work commercially, no matter how small the profit margin, then it will represent a possibility to commoditize CO_2 rather than simply treat it as a waste product.

It is even possible to develop geothermal energy in rock that has very low permeability, albeit less efficiently than for open-loop geothermal systems. Single-well geothermal systems rely on conduction to heat the fluid in a well's annulus. The warmed fluid is returned to surface up the centre of the well and heat is extracted before the same fluid is injected via the well's annulus (Falcone *et al.* 2018) through a 'counter-current' heat exchanger. Such systems are currently at the centre of commercial development and deployment by several companies. The main advantage is the need for only a single well with consequentially reduced development costs.

Energy storage and waste disposal

Energy storage is straightforward when dealing with solid materials such as wood, coal and even fissile materials with little energy cost over and above that required to produce the solid fuel and move it to the site where it will be used. Heaps of coal at power stations is still a common site in many parts of the world. Coal can degrade at the Earth's surface but does so slowly. Pumped storage is also a simple, albeit energy-intensive method, involving moving water uphill to a reservoir ready for it to be used for hydroelectric generation when required. The following subsections examine the temporary and permanent storage of fluids including air, methane, hydrogen and carbon dioxide, as well as heated fluids.

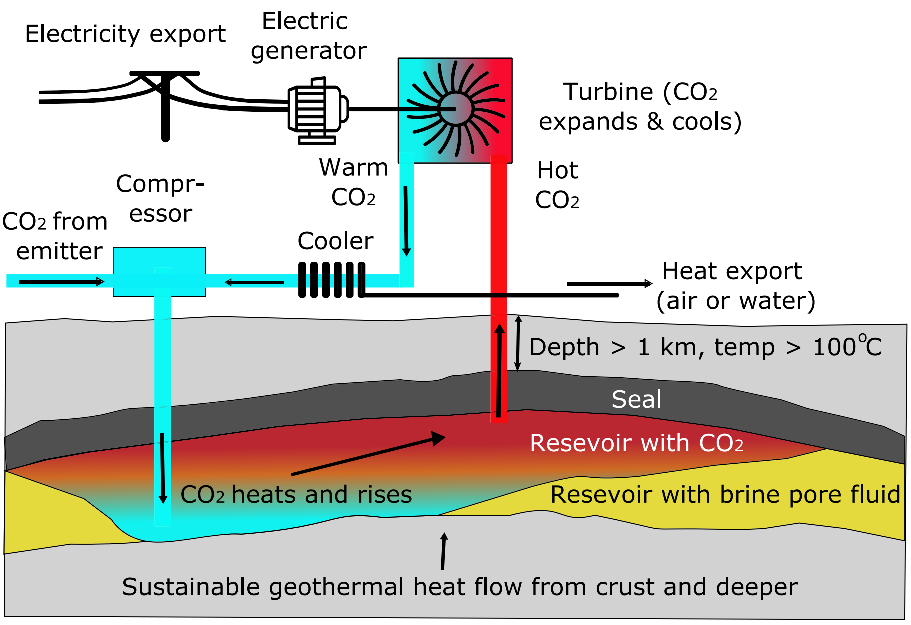

Fig. 6. CO_2 plume geothermal (CPG) system. Source: modified by a figure originally drawn by Martin Saar; generator from Saurus Icon, turbine by Arthur Shlain of the Noun Project (both Creative Commons).

Syngas

Syngas, also referred to as manufactured gas or town gas, is a mix of hydrogen, methane, carbon monoxide and carbon dioxide. It tends to be stored on the surface in large telescopic cylindrical containers – gasometers, the pressure within which is controlled by extending and reducing the cylinder height. Such gasometers were once a common site in UK towns but were progressively decommissioned and removed as North Sea gas displaced town gas.

Natural gas and biogas

Both natural gas and biogas are predominantly methane; the former is classified a fossil fuel and the latter a renewable fuel. Natural gas storage and retrieval in either salt caverns or porous media (most often spent gas fields) is already commonplace. These same sites could also be used for biogas storage without modification.

The use of natural gas as a major fuel source for a nation presents more of an issue because of the vast quantities required, at least for nations that need to import it in substantial quantities. Such gas tends to be stored in the subsurface in manufactured salt caverns or in porous media such as saline aquifers or depleted petroleum fields. For example, France and Germany, both nations with only modest domestic natural gas fields, each has about 100 days of supply in storage. For the UK, the situation is different. It developed little storage capacity because it had many gas fields, especially those in the North Sea, connected directly to the national gas grid, and the contracts between producers and gas distribution companies ensured a secure supply. Nothing was changed when in 2004 the UK ceased to be able to meet the demand from domestic supply and imports began. At that point the UK had about 14 days of storage capacity, much of which was in the offshore Rough Field (Stuart 1991) that was capable of holding 100 Bcf (2.832×10^9 m^3) of gas; but this was closed in 2017 (and is now being re-examined with a view to recommissioning). The UK now imports about 60% of the natural gas it uses and lacks storage facilities, thus being at the mercy of nations from which it receives its supply. The vulnerability of gas supply into many countries in Europe has been exposed in the wake of the Russian invasion of Ukraine (began February 2022) as Russia is a major gas supplier to much of Europe (Di Bella *et al.* 2022).

Hydrogen

When considering the possibility of a switch to an economy that uses hydrogen as an energy storage vector, rather than one fuelled by petroleum, the safe, reliable storage of large quantities of hydrogen becomes an issue. Geostorage of hydrogen is possible and small-scale systems have been operational for decades. The most common geostorage facilities are manufactured salt caverns (Stone *et al.* 2009; Portarapillo and Di Benedetto 2021). Porous media storage sites are few and are limited to depleted petroleum reservoirs in Argentina (Sambo *et al.* 2022). No purely hydrogen storage sites have been developed in saline aquifers, although town gas has been stored in this way at a few locations in Europe (Muhammed *et al.* 2022). The properties of hydrogen are such that it presents a few problems not encountered when storing natural gas.

Hydrogen can be geostored as a compressed gas but not as a supercritical fluid because the increased pressure alone is insufficient. Cryogenic temperatures are required, and these are incompatible with subsurface storage for which the temperature will increase with depth in accordance with whatever the geothermal gradient is at the storage site. This means that for a given pore volume, the quantity of hydrogen that can be stored is substantially less than for hydrocarbon gases (Fig. 7). At a typical virgin reservoir pressure of about 25 MPa and temperature of 350 K (73°C) (as for many Permian Rotliegend sandstone reservoired fields of the Southern North Sea), methane would have a density of *c.* 125 kg m^{-3} and hydrogen 25 kg m^{-3} (and carbon dioxide 722 kg m^{-3}). The energy density of hydrogen, per unit mass, at 142 MJ kg^{-1} is much higher than that of methane at 55.5 MJ kg^{-1} but since the methane has a density about 5 times that of hydrogen, at standard temperature and pressure, then the overall effect is that a little over twice the volume used for methane storage would be required for hydrogen to deliver the same calorific value.

Hydrogen is also very reactive and is a favoured energy source by a variety of bacteria common in the deep biosphere. In recent years evidence has emerged of natural systems in which abiotically generated natural hydrogen has been converted by bacteria into methane and other light alkanes (Flude *et al.* 2019; Karolyté *et al.* 2022). The speed of such biologically mediated reactions is fast, occurring over years to decades. This has significant implications for even seasonal geostorage of hydrogen (Thaysen *et al.* 2023). Even partial conversion of stored hydrogen to methane would add significant costs to storage and may even render sites unusable. There are workarounds to limit the bio-reaction process that could include deep storage at temperatures higher than 122°C (Thaysen *et al.* 2023), typically equating to a depth of more than 4 km depth in the North Sea, or in supersaline aquifers. It may also be possible to limit bacterial activity simply as a function of the pressure in the

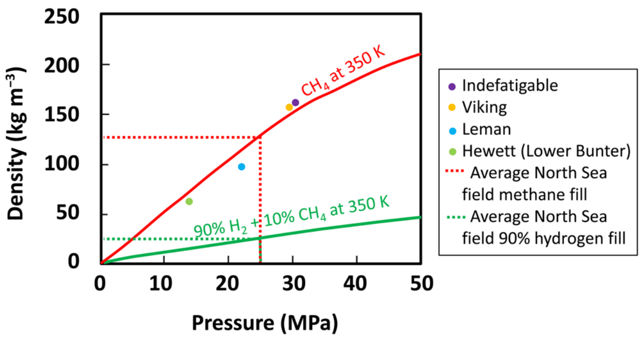

Fig. 7. Pressure–density relationships for methane and a 90% hydrogen–10% methane mix at a temperature of 350 K (77°C) typical of gas fields in the Southern North Sea. A few major fields that might be considered for hydrogen storage are also plotted. Their positions slightly above the 350 K isotherm reflect slightly higher or lower reservoir temperatures. Source: the methane curve was constructed from data in Friend *et al.* (1989) and that for the hydrogen–methane mix is from Hassanpouryouzband *et al.* (2020).

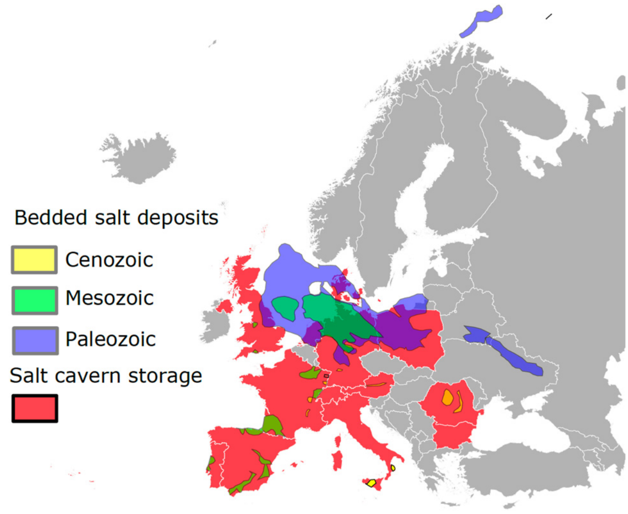

Fig. 8. Distribution of bedded salt deposits in Europe and countries with developed salt cavern storage (shown in red) of natural gas, oil and/or other gases. Source: compiled from figures and data in Breivik (1998), Crotogino *et al.* (2010) and Caglayan *et al.* (2019).

storage system. A small number of studies have been interpreted to indicate that once bacterial populations are exposed to an excess of hydrogen, as would be the case in high-pressure hydrogen storage, the hydrogen loss rate does not increase over that seen in experiments at standard temperature and pressure (Heinemann *et al.* 2021). Nonetheless, depleted oil and gas fields that are currently favoured may not in many instances be suitable because they do not exist in conditions that would preclude bacteria.

Compressed air energy storage (CAES)

Energy storage using air compressed during periods when renewable electricity generation exceeds demand can be undertaken in manufactured salt caverns or possibly in subsurface porous reservoirs. Key considerations include ensuring that the overburden at the storage site can withstand repeated and possibly rapid pressure changes as the storage site is charged and then discharged with air, as well as dealing with the heat generated during compression and the subsequent heat required as the air is discharged for power generation. Currently there are only a few systems in operation, including Huntorf in Germany. This became operational in 1978 and has a power rating of 290 MW (Wang *et al.* 2017). The McIntosh CAES plant in Alabama, USA has been on stream since 1991 and generates 110 MW peak during the discharge phase. McIntosh operates using a salt cavern 67 m in diameter and with a volume of *c.* 32 000 m^3 and has a 2860 MWh capacity (Wang *et al.* 2017).

Both of the above plants require combustion of natural gas for the heating phase, and clearly this is not acceptable for a carbon-free or low-carbon energy future. In both instances the efficiency of the systems is around 50%, meaning that only half of the energy put into charging and discharging them is usable at the discharge phase (Wang *et al.* 2017). Round trip (compression, expansion) efficiency has a maximum of *c.* 70% (Bazdar *et al.* 2022).

It is interesting to speculate on where CAES might be developed and what form the storage may take. The main salt deposits in Europe are Permian and Triassic, with smaller areas containing Paleozoic salt basins, many of which already contain manufactured salt caverns that are used to store a variety of bulk fluids (Fig. 8). Such areas could host compressed air storage, although consideration needs to be given to the integrity of the salt when subjected to rapid loading, unloading and temperature oscillation during the CAES compression and expansion cycles (Martin-Clave *et al.* 2021).

Another possibility is to use depleted petroleum fields or saline aquifers as porous media CAES (PMCAES) storage systems. A theoretical and likely advantage to such systems would be the ability of the stored compressed air to maintain its temperature or even be heated by geothermal heat. The potential for natural geothermal heating of the stored air would dramatically improve the round-trip energy efficiency of the storage system.

An important consideration would be the permeability of the storage reservoir at and local to the injection–production well(s). The permeability needs to be high to enable pressure to dissipate away from the wellbore during injection and to provide pressure support during production. There is already experience of gas (methane) injection in several fields in the North Sea and East Irish Sea. Both the Statfjord Field (Gibbons *et al.* 2003) on the Norway–UK median line and the Ula Field (P. Zhang *et al.* 2013) on the Norwegian Continental Shelf have injected gas for EOR in what is known as a water alternating gas (WAG) process. The Magnus Field has also seen gas injection, with the gas being transported by pipeline from the Foinaven and Schiehallion fields on the Atlantic Margin to support EOR (Macgregor *et al.* 2005). These examples demonstrate that injection of gas into a subsurface reservoir is possible. However, subsurface environments are typically anoxic. Thus, the introduction of oxygen is likely to cause oxidation of some minerals and consequential impacts on pore fluid properties, including acidification, as well as possibly weakening the rock fabric.

Another field, the Lennox Field in the East Irish Sea, has also been taken through a protracted gas-injection phase followed by gas production (Bunce 2020). This field may be the model for a different kind of large-scale compressed air storage scheme using less aggressive injection rates than salt caverns or some porous media storage sites. At the time of discovery, Lennox comprised a thick gas column of 226.8 m overlying a thin oil leg of 43.6 m, with both sitting atop a very active aquifer. The oil was developed first using horizontal wells drilled in a radial pattern (Fig. 9). Each well was placed close to the oil–water contact but to prevent coning of the lower-viscosity water into the oil production wells, the pressure was increased in the gas column by the injection of gas from elsewhere in the Liverpool Bay complex of fields. On the completion of oil production, the field was turned over to gas production with the natural ingress of the aquifer aiding gas recovery. Thus, the Lennox Field development history has demonstrated the elements required for compressed air storage at a large scale, with *c.* 18 Bm^3 of gas recovered during the final phase of field production (Bunce 2020). There are quite a few gas fields that have very active aquifers, including the Frigg and NUGGETS fields (De Leebeeck 1987; Saha

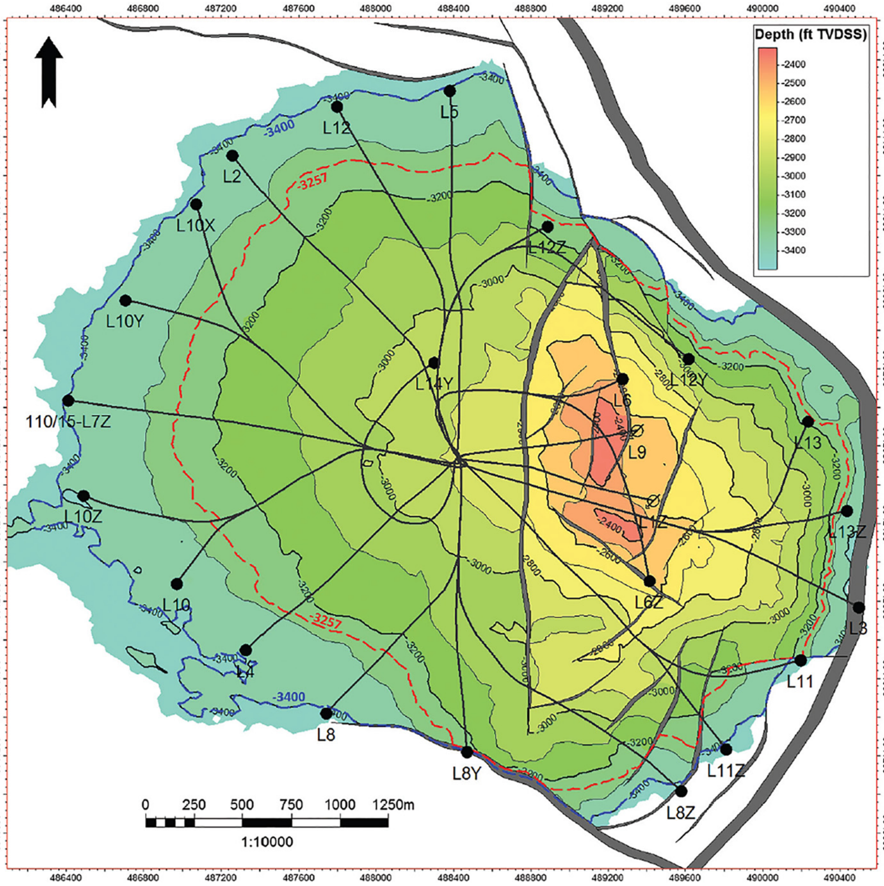

Fig. 9. Top reservoir structure map of the Lennox Field (Ormskirk Sandstone Formation) showing the horizontal development wells and the original field fluid contacts (the oil–water contact is shown as a dashed blue line; the gas–oil contact is shown as a dashed red line). TVDSS, true vertical depth subsea. Source: from Bunce (2020).

et al. 2014). It is therefore possible that such systems could be used for compressed air storage with the active aquifer providing pressure support.

Heat storage

The demand for heat in the populated global north in both temperate regions in winter and for longer periods in Arctic locations is high. For example, in the UK about half of all the energy used annually is for heat production (Gluyas *et al.* 2018*a*). The opportunity to meet such heat demand using geothermal energy alone is possible. The experience in Iceland is that the inflow of heat is sufficient to keep pace with heat abstraction in many geothermal developments (Stefánsson 2000). However, Stefánsson (2000) also recognized that the extraction of heat from the subsurface may occur more quickly than it can be replaced by heat inflow from adjacent volumes of rock when cooled water is reinjected (Gong *et al.* 2011). Another approach is to inject heat, the source of which could be waste heat from industry or harvested solar heat (Gluyas *et al.* 2020; Albert *et al.* 2021).

The mine water geothermal project at Heerlen in The Netherlands injects waste heat from industry and other sources; accumulating heat during the summer months and producing it in the winter when demand is high (Verhoeven *et al.* 2014). A comparable project Heatstore in Germany is harvesting heat from solar thermal panels and, as in Heerlen, storing the heat in abandoned and flooded mines (Kallesøe *et al.* 2021). Mines are not the only storage option; porous media (sedimentary rocks) also present an option for storage. Work undertaken for the UK's Energy Technology Institute has explored the possibility of storing heat in porous shallow sandstones close to major power stations (ETI 2011). Given that typical coal- or gas-fired stations are only 30–50% efficient at converting the chemical energy in fossils fuels into electricity and wasting the rest as heat, such storage options could vastly improve the total efficiency and thus sustainability of fossil fuel or even nuclear power generation.

Carbon storage

The global consumption (combustion) of coal oil and gas led to the emission of 40 Bt of carbon dioxide in 2022, the highest annual quantity ever recorded. Since the Industrial Revolution began, the concentration of this potent greenhouse gas in the Earth's atmosphere has risen from *c.* 280 ppm to *c.* 430 ppm. This increase in CO_2 concentration is the main agent driving anthropogenically induced climate change (IPCC 2023).

Capture and geostorage of much of the generated CO_2 is possible and the processes proven, only a lack of political will in many countries to create the business case to promote carbon capture and storage (CCS) is holding back its widespread uptake. Progress is slow because it is a loss-making waste disposal process and because first-mover nations will, it is often claimed, put themselves at a financial disadvantage if they spend money capturing and burying CO_2 relative to those that do not. Even so, many countries now have active storage schemes and many more are in the development stage (Fig. 10). The estimate of global, permanent storage potential is highly uncertain, with the most recent figure available being between 8000 and 55 000 Bt (Kearns *et al.* 2017). Despite this uncertainty, Y. Zhang *et al.* (2022*b*, 2023) showed in two studies based in Europe and the USA that the intrinsic storage capacity of the subsurface is substantially larger when considered on a multi-national or continental scale than any targets published for Europe and the USA. Y. Zhang *et al.* (2022*a*) also showed, using publicly available data, that 29 Mt of CO_2 was geologically stored in 2019, with a cumulative total for the period 1996–2020 of 197 Mt.

The most common storage sites are in depleted petroleum fields and deep saline aquifers. Other options exist such as at Carbfix, a

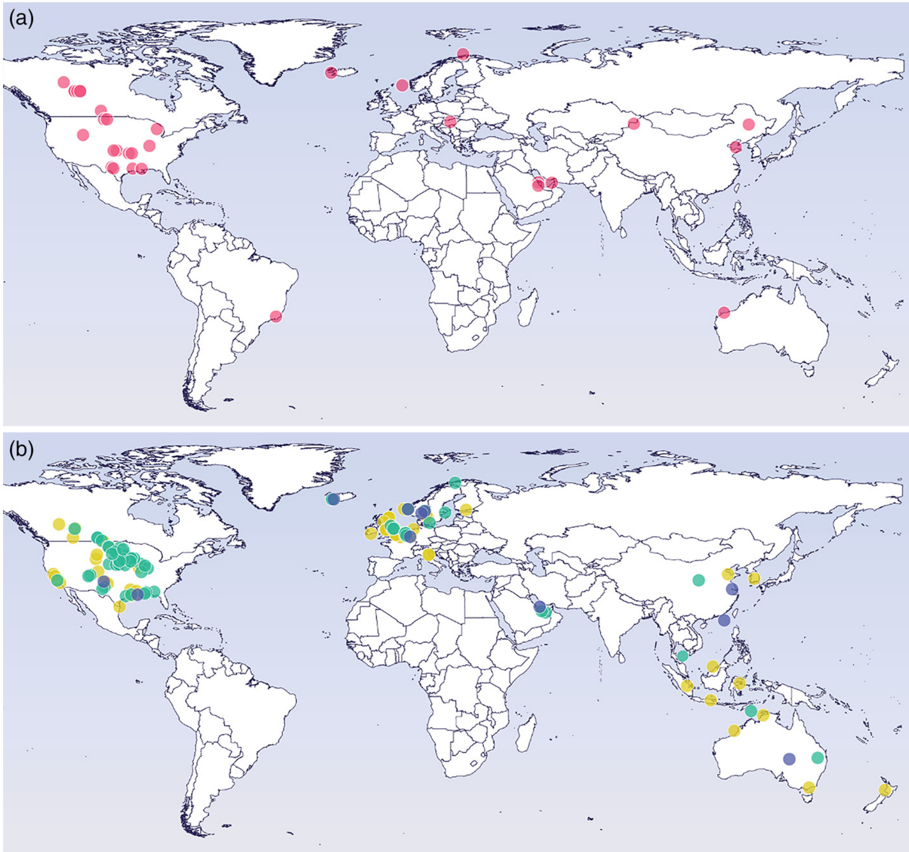

Fig. 10. Global distribution of carbon capture and storage (CCS) projects: (**a**) operational and (**b**) in construction (blue), advanced development (green) and early development (yellow). Source: from Global CCS Institute (2022).

project in Iceland that is extracting CO_2 from its geothermal systems and injecting it into basalt where alkali earth metals react with the CO_2 and sequester it (Kristjánsdóttir and Kristjánsdóttir 2021). Similarly, Dobrzanski (2016) demonstrated that industrial waste streams containing alkali earth metals could also be used to sequester CO_2 and produce a stabilized bulkier and potentially commercially useful product.

For systems in which the carbon dioxide would be stored as a dense-phase (supercritical) fluid, the key attributes required of a site are similar to those needed for a natural petroleum accumulation. The receiving reservoir needs to be both porous and permeable, and to be able to hold and transmit fluids. The reservoir also needs to be capped by a low-permeability seal rock. Former depleted oil and gas fields have the advantage that there is clearly pressure (pore) space into which the CO_2 can be injected. The disadvantage of such sites is that the reservoir pressure may be so low that any injected dense-phase CO_2 would transform to the gas phase with concomitant adiabatic cooling that could freeze the rock and its pore fluids (Joule–Thompson effect: Mathias *et al.* 2010). Storage sites in saline aquifers would not suffer from the Joule–Thompson effect when CO_2 is injected but may need to produce brine to enable the injection of CO_2, leastways if the bottom hole pressure in the injection well begins to rise.

The integrity of the seal needs to be retained during the injection period and possibly for centuries thereafter (IPCC 2005 suggest 99% retention of CO_2 for 1 kyr), and while geological risk (of leakage) is rarely considered to be anything but very low, concerns remains about the integrity of any old wells on the storage site. These, however, can be monitored, and remedial interventions enacted when needed.

The UK along with North Sea neighbours, Norway and The Netherlands, have a huge array of potential storage sites in both depleted petroleum fields and saline aquifers on their continental shelves (Fig. 11). That such sites are generally well characterized is a legacy of some 60 years or more of petroleum exploration and development in basins ranging from offshore Arctic and Mid-Norway to west of Britain, the East Irish Sea, Celtic Sea, Western Approaches, English Channel, and, of course, the UK, Norwegian, Dutch and other sectors of the North Sea. Rystad Energy (2020) estimated that by 2035 up to 75 Mt of CO_2 could be captured annually and geostored in the UK, Norway, Denmark, The Netherlands, Italy and Ireland, with about 80% in UK projects. This compares with total emissions for the six countries of over 1000 Mt in 2021 (data from UK CCC and European Environment Agency). This means that only 7.5% of the CO_2 produced is captured, while 92.5% is emitted.

To date, the UK has stored zero tonnes of CO_2, with first injection planned to begin at two sites in 2025. HyNET will store CO_2 in the depleted Hamilton Field in Liverpool Bay (Becker *et al.* 2021), the CO_2 derived mainly from (blue) hydrogen manufacture, whilst the Northern Endurance Partnership (Sovacool *et al.* 2022) will take CO_2 from both the Drax power station in Lincolnshire and from a suite of industries on Teesside, and store it in the huge Endurance site, a saline aquifer, offshore Norfolk, eastern England (Gluyas and Bagudu 2020). The CO_2 from Drax will be captured from the combustion of biomass and is claimed that this will thus be carbon negative. This may well be true given the way carbon accounting works but the claim is much less firm when one considers that the biomass comes from mature trees felled, dried and pelleted in North America (Carrington 2022).

Norway has a long record of CO_2 storage, having begun with the Sleipner system in the South Viking Graben in 1996 and now with additional site Snøhvit. The annual CO_2 stored is up to 1.7 Mt (Norway Petroleum n.d.; Eiken *et al.* 2011; K. Zhang *et al.* 2022) relative to annual national emissions of around 40 Mt.

Carbon geostorage is often referred to as a transition technology, meaning that once humanity has weaned itself off burning fossil fuels for power (electricity generation), transport and heating that it will no longer be required. This, however, is not so if humanity continues to use concrete and steel. Cement production and steel

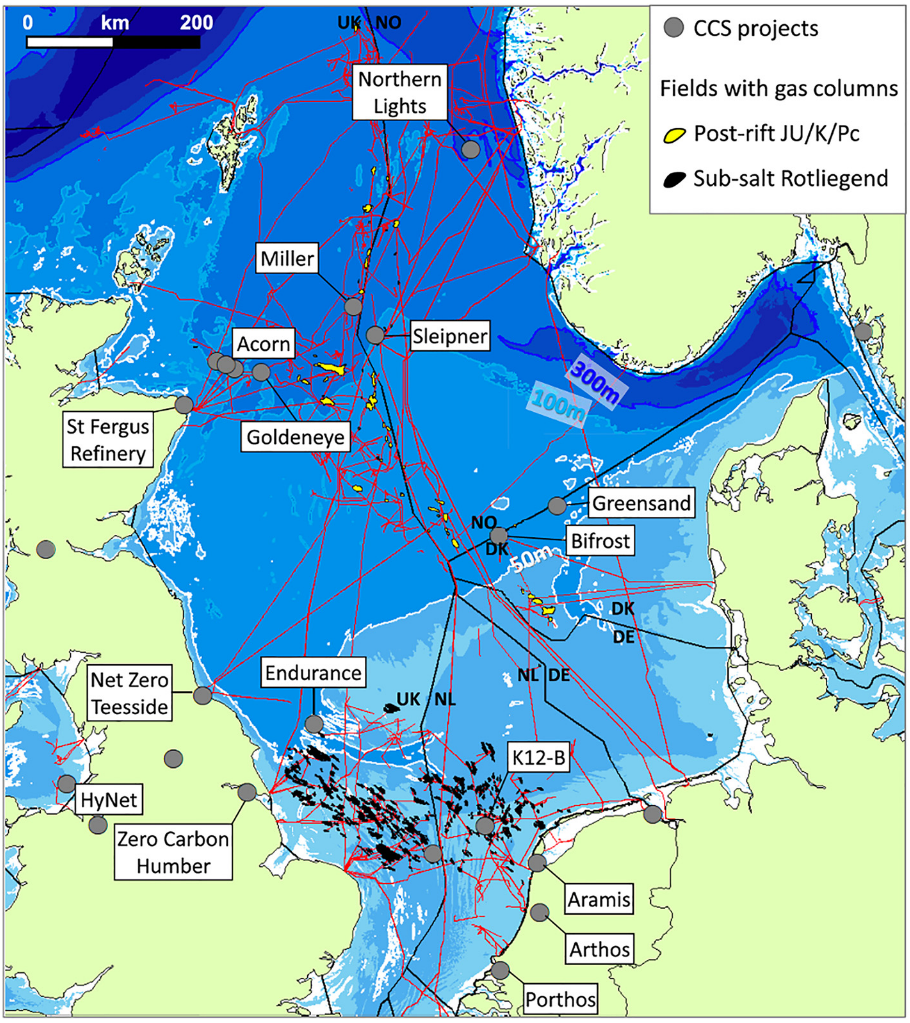

Fig. 11. Map of the North Sea Basin showing carbon dioxide disposal projects and fields with demonstrable gas seals. The grid is water depth, with 50 100 and 300 m bathymetric contours shown. Source: the data come from Scottish Carbon Capture and Storage, OGA, NLOG and EMODNet, collected April 2020 to January 2021; from fig. 7 of Quirk *et al.* (2022).

making are inherently CO_2-producing processes, the former because cement is made by roasting limestone until it breaks down into its constituent lime and carbon dioxide, the latter because carbon in the form of coke is used to combine with the oxygen in iron oxide, thus releasing iron from its ore. So these processes and several others will emit CO_2 that must be captured and stored. CCS will be with us for the foreseeable future and nations that have and are developing it will be able to monetize skills and spare storage capacity in order to accommodate those countries that are late to adopting the process.

Geopotential and geokinetic energy

Primary recovery of both gas and oil relies upon the conversion of potential energy in the trapped petroleum and its conversion to kinetic energy as it flows up a well to the surface. This occurs even when the system is normally pressured (hydrostatic pressure). For gas this is simply an expansion process, enabled when the wellhead pressure is reduced to less than that of the subsurface confining pressure. Gas expansion can in the most permeable gas fields enable recovery of more than 90% of the gas without any intervention (Fig. 12). A different process operates in oilfields. Most natural oils in the subsurface contain dissolved gas. By lowering the pressure at the wellhead, gas evolves from the oil and lifts it to surface. At worst, this may only bring a few per cent of the oil to the surface before the excess pressure is depleted. At best, perhaps as much as 30% of an oil can be recovered if it is gas rich at the initial conditions (Gluyas and Swarbrick 2021).

There are natural systems in which the pressure in the subsurface is well above hydrostatic pressure. Such overpressured or geopressured systems, as they are called, have an even greater potential energy than hydrostatic systems. Geopressured fluids include water, petroleum and non-petroleum gases.

We are not aware that anyone has harnessed the kinetic energy in systems allowed to flow to the surface. Hunt (2007) suggested that a combination of the high and temporally variable pressures in gas wells precludes the use of conventional turbines to generate electricity from the flow of fluids up-well. Instead, Hunt proposed use of a piston ram system but this seems not to have been trialled. Z. Li *et al.* (2023) calculated what they termed the geostress energy potential of major natural gas-producing countries on the basis that the Earth is continuously outgassing and therefore pressure recovery in abandoned wells (and fields) is inevitable. Perhaps unsurprisingly, the potential energy in such systems is very high, accounting for up to *c.* 90% of the total energy available before the exploitation of petroleum. The difficulty of utilizing the geostress energy is significant and has not been realized except in a few instances where natural repressurization of petroleum systems has occurred during protracted periods of non-production fields. A well-documented example of repressurization due to aquifer inflow occurred in the North Sea's Argyll Field. It was twice abandoned and twice redeveloped (as the Ardmore Field and then the Alma Field – the change in name being required because, from a legal perspective, the field ceased to exist once abandoned). Initially abandoned from 1992 to 2003, the field recovered about two-thirds of its initial pressure (Gluyas *et al.* 2005) and during a second

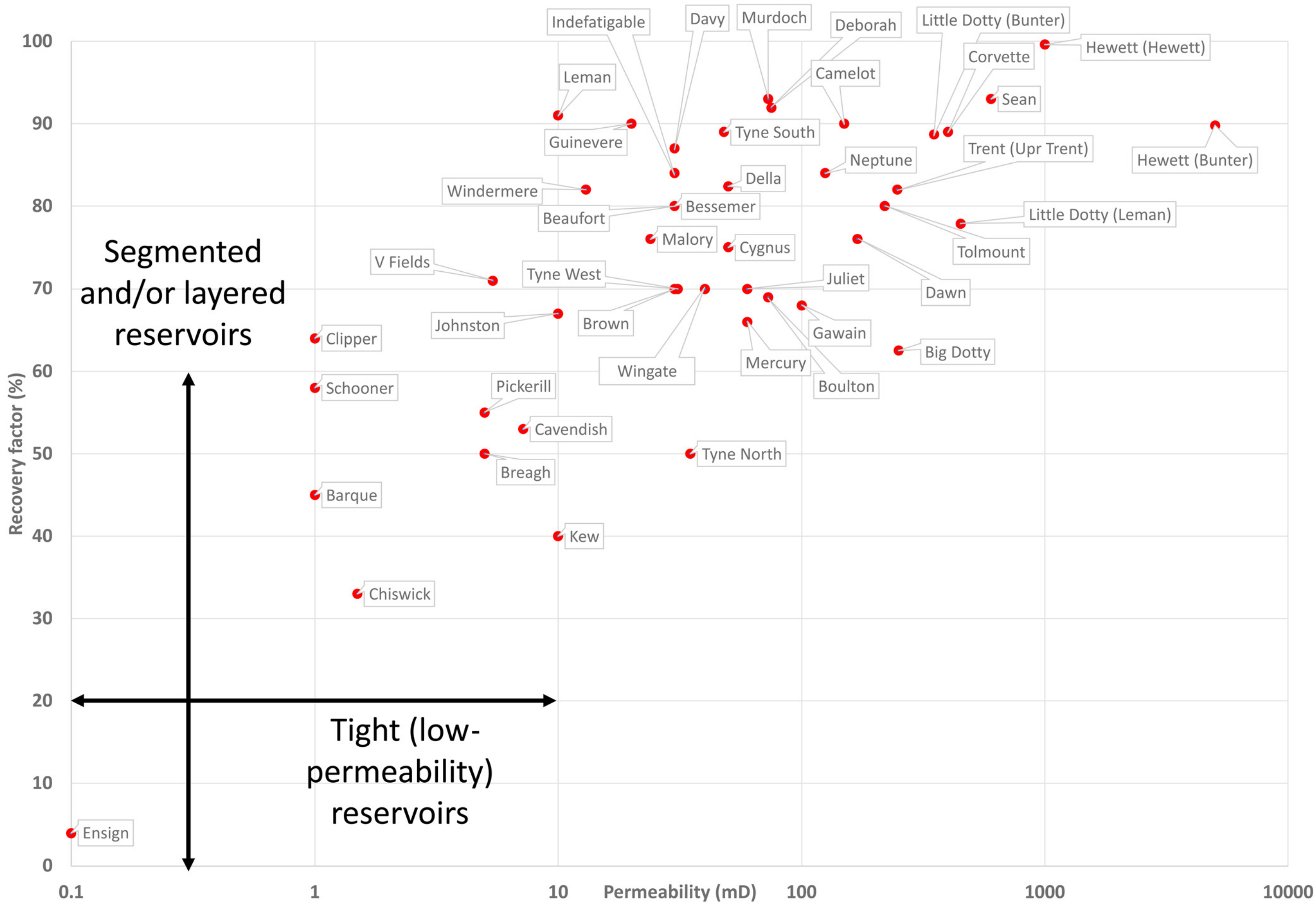

Fig. 12. Recovery factors for Southern North Sea gas fields compared with the average permeability of the reservoir intervals. The horizontal arrow indicates low-permeability reservoirs from 0.1 to 10 mD; the vertical arrow indicates reservoirs that are also likely to be layered and or segmented. Source: data from Gluyas and Hichens (2003) and Goffey and Gluyas (2020).

abandonment, from 2005 to 2015, there was further pressure recovery (Gluyas *et al.* 2018*b*; Tang *et al.* 2020).

Subsea hydroelectric generation

The way in which normally pressured oilfields are developed, as well as both normally pressured and overpressured gas fields, provides an interesting opportunity for end-of-life power generation. We are not aware that this idea of what we term ‘subsea hydro’ has been published elsewhere, although the background technology is a very old one, deployed many times over and referred to as ‘dump flood’ in oil industry vernacular. Gas fields are produced by gas expansion and pressure depletion. At cessation of production, the pressure in the reservoir will be low and out of hydrostatic pressure equilibrium with adjacent rocks. A similar situation commonly exists in depleted oilfields, even if they have had secondary recovery through water injection. This is because fields are typically managed to maintain a reservoir pressure just above bubble point (of gas from the oil) and typically at a significantly lower pressure than virgin pressure.

Basically, water can be poured down wells fitted with a turbine. The falling water drives the turbine and generates power. Analytical work undertaken by Arun Tekchandani, an MSci student at Durham University, in 2022–23 suggested the power generation potential of eight near end-of-life gas fields in the UK to be 1.5 TWh over the power-producing period of up to 26 years (Tekchandani 2023).

A particular advantage to be realized from subsea hydro is that the water flows into the reservoir and thus, once energy extraction is complete, the pressure in the old field will then be returned to hydrostatic or thereabouts. This will reduce or possibly eliminate future incidences of induced seismicity and surface/seabed subsidence as the reservoir section compacts (Gee *et al.* 2016), and hence is an environmentally desirable pre-abandonment process for pressure-depleted oil and gas fields.

Low-grade heat supply

Any number of processes that require moderate or large quantities of heat could use geothermal heat as a sustainable, ultralow-carbon source. Figure 13 lists the temperatures required for various industrial processes. The total energy requirements will be dependent on the quantity of material in the process and its duration. Typically, such processes would use heat generated by burning fossil fuels or electrical heating. Instead, we illustrate in Figure 13 the depth requirement for extraction of geothermal heat for each of these processes based on a surface temperature of 10°C, a minimum thermal gradient of 20°C and maximum temperature of 40°C. The potential carbon (emissions) savings for the individual industries illustrated in Figure 13 are large.

Thermochemical heat storage could also benefit from using geothermal energy to prime systems. Jarimi *et al.* (2019) reviewed the potential for using solar thermal and/or waste industrial heat for thermochemical heat storage but use of geothermal energy could be attractive because it is more reliable than solar thermal and has better sustainability than waste industrial heat. Thermochemical systems typically deploy the properties of materials through hydration/dehydration or adsorption/desorption cycles. They can be dehydrated and desorbed using low-grade heat, whereas the hydration and adsorption processes commonly operate at much higher temperatures. A further advantage of using thermochemical heat storage is that the ‘charged’ materials are stable, do not lose heat,

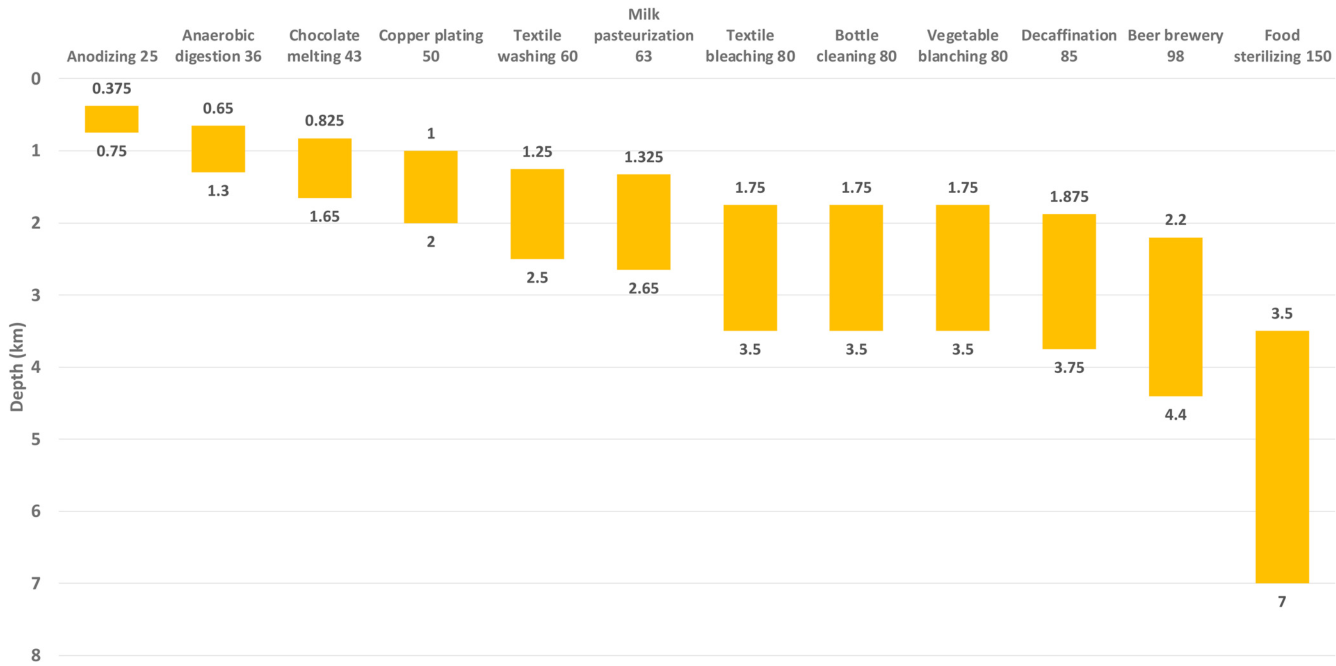

Fig. 13. Common industrial-scale processes and their temperature requirements (°C) and potential geothermal heat-extraction depth range based on minimum and maximum geothermal gradients in the UK. For example, coffee decaffeination would require heat to be abstracted at a depth anywhere between 1.875 and 3.75 km depending on location in the UK to obtain a temperature of 85°C.

unlike heat storage, and therefore can be transported to where needed without the cost of insulation.

Geo-engineered systems

In the earlier subsection on 'Carbon storage, geostorage was mentioned but the Icelandic CarbFix demonstration project was not elaborated upon. In CarbFix, the CO_2 injected into basalt reacts with magnesium and calcium to produce carbonate minerals, permanently sequestering the carbon dioxide as solid minerals. A similar but larger project is current in Oman. It was observed some years ago that mantle-derived peridotites forming the Omani Mountains, and which are rich in calcium and magnesium, are reacting with the carbon dioxide in percolating meteoric water and depositing carbonate minerals as fracture fills (Matter and Keleman 2009). The Climeworks Oman project is, in essence, simply speeding up this process by reacting the rock with direct, air-captured carbon dioxide (Gebeily 2021). The potential is calculated to be 1 t of CO_2 per 1 t of peridotite, yielding a sequestration potential of 50 Tt of CO_2 for Oman alone. Some experimental projects, however, have shown that whilst the minerals on fracture surfaces of mafic rocks can react quickly with injected carbonate-bearing solutions to precipitate carbonate minerals, the reaction can become self-limiting as the precipitated minerals coat the unreacted rock and fill the fracture volume (Xiong *et al.* 2017).

What seems not to be captured in these true sequestration projects or other similar ones is that the reaction between CO_2 and mafic rock (olivine) is highly exothermic. Schuiling (2006) suggested the heat generated thus generated could be used. However, Hangx and Spiers (2009) challenged the hypothesis on the basis that reaction rates and, hence, heat generation would be too slow to be significant unless the grain size of the olivine was of the order of 10 µm.

Carbonation is only one of several possible geo-engineered systems. Earlier in this paper we also discussed the origin of natural hydrogen, with one natural process being serpentinization. Here too the processes could be speeded up. Hydrogen produced from the interaction of iron and magnesium by the injection of water deep into mafic rock has already been dubbed 'orange', although, as yet, orange hydrogen is only a concept (Osselin *et al.* 2022).

There is also a possibility that some geological systems could be deployed directly for thermochemical heat storage. The hydration and dehydration of the gypsum anhydride system would seem an obvious candidate, whilst Grosu *et al.* (2016) examined the use of iron ore deposits (magnetite) in Sweden as a heat storage utility.

Petroleum production decarbonized

Humanity has relied on energy-dense oil and natural gas to develop nations, power the world's industry, and for transport and home comforts since the twentieth century began, and whilst most governments now recognize the ongoing impact on climate change driven by combustion of petroleum, there is no real sign that humanity will stop searching for it or producing it in the near- or even mid-term future. We have already examined CCS as a climate-change mitigation process but CCS as currently conceived applies only to the end-product use of gaseous and liquid petroleum. The process of production is also a source of greenhouse gas emissions and that need not be so. For example, the Scottish oil (and gas) industry operating processes accounts for around half of Scotland's 41.6 Mt of CO_2e emitted annually. The greenhouse gases are emitted because of power generation, flaring and lesser gas venting. Flaring and venting can be eliminated, and the impact of power generation substantially reduced.

Flaring and venting are used to dispose of unwanted hydrocarbon gases that exsolve from the oil when it is brought to the surface. In most Scottish offshore fields, the gas is exported or used for power generation but there are a few where flaring occurs because there is an excess of gas over that needed for power generation (NSTA 2022). Elsewhere in the world, natural gas may be valueless as export facilities do not exist. Either way, flaring and venting are a major waste of a valuable energy resource. Gases exsolved during production can be reinjected to improve recovery from the field from which they are produced. This has occurred for several fields in the UK and Norwegian sectors (South Brae, Statfjord and Ula: Fletcher 2003; Gibbons *et al.* 2003; Hinderaker and Njaa 2010). As mentioned earlier, in one instance, unwanted gas from the Schiehallion oilfield on the Atlantic Margin was to have been flared but bp, in a move specifically designed to reduce GHG emissions, constructed a pipeline 400 km in length to transport the gas to the Magnus Field in the North Sea, where it was used for EOR (Macgregor *et al.* 2005).

Much more significant than flaring is the generation of CO_2 from combusting raw gas for power generation. We have already examined the role that co-produced hot water could play in power generation (Auld *et al.* 2014) but such systems will not produce all the power required because the water is not hot enough. The Norwegian industry has progressively replaced gas burning for power with electricity generated onshore using hydro. When this is not an option, the CO_2 generated when gas is burned for power or as flaring can be captured and reinjected with water as so-called 'fizzy water'. It too will help to increase recovery (Esene *et al.* 2019).

Integrated imagineering – a geoenergy future

What we have tried to do in this study is to examine the range of ways in which the Earth's resources can be used in a sustainable and environmentally responsible way to deliver energy for humanity's future. We have based much of our analysis on the way in which the UK has evolved as an energy-rich nation to one in which the future of energy supply is much less certain and considerably less secure. We have argued that the UK need not be energy poor but our work has amounted to little more than a list of possibilities. What is also clear is that there is no single energy source or technology that will deliver energy security, sustainability and affordability. Instead, we need a combination of technologies to harvest, store and distribute energy, and to balance that while simultaneously using much less energy.

Here we look at the future for the Southern North Sea in energy terms. As junior school children of the 1960s we knew the sea offshore East Anglia, UK as fishing grounds for whiting and plaice, both providing energy for the body. Following discovery of gas at what is now West Sole in 1965, the North Sea fish narrative was replaced by a North Sea gas narrative. The story changed again this millennium to offshore wind-generated electricity. Whiting and plaice aside, a future for this part of the UK's continental shelf could include clean energy provision from wind and from within the Earth.

The Southern North Sea currently (at end 2021: TCE 2021) has 11.3 GW of installed capacity with an efficiency measured over a whole year of about 41% (EWEA n.d.), meaning that at periods of no wind or occasionally too high a wind the power output is low or zero. A backup system that would allow the wind farms to act as a base load is highly desirable and possibly an imperative. Several of the geoenergy processes described above could be used to deliver the power generation continuity required of a base-load provider. The most straightforward of the options is to install subsea hydro on low-pressure, end-of-life gas fields and connect the power output to the wind power generation grid. When low wind conditions occur, the power output could be topped up by simply opening the valves and allowing seawater to flood into the depleted field via the turbines installed in wells.

It is possible to imagine a rather more complex process that could involve the development of some of the hundred or so undeveloped gas discoveries and poorly developed fields in the North Sea (Aberdeen and Grampian Chamber of Commerce 2023). Currently, no critical analysis of the possibilities has been undertaken and, as such, the following section is speculative. Instead of transporting gas to shore, it would be burned offshore for power generation, and the exhaust gases captured and reinjected. Combustion of the methane using oxyfuel would be most sensible because the products would only be CO_2 and some water vapour, both free from contamination by air. This should reduce both the cost and energy penalty of the capture process relative to post-combustion capture. Oxygen could be produced on site either by cryogenic separation from air or possibly through electrolysis of desalinated seawater using surplus electricity from the wind farms at periods of low demand. If generated from water, then hydrogen would also be a valuable co-product. The CO_2 produced during combustion could be injected downdip of the producing wells to effect enhanced gas recovery (Goudarzi 2016) until such time that the injected CO_2 reaches a saturation of about 55% (corresponding to >98% CO_2 saturation in the production well), whereby CO_2 plume geothermal (CPG) power generation could be started (Ezekiel *et al.* 2022; Jefferies 2022). The whole series of processes would be carbon neutral. It would ensure that the UK makes best use of its natural gas and once in CPG mode would deliver a sustainable, base-load complimentary process for the wind-generated electricity used by the nation.

Summary and Conclusions

The Earth's crust has delivered the world's energy needs since the Industrial Revolution began. Mined and combusted coal, oil and gas have delivered the energy for heating, transporting and industrializing human society. The impact of doing so has been recognized in recent decades as driving climate change. Geoenergy is, however, more than fossil fuels.

The little exploited heat of the Earth has a very low carbon footprint, and such geothermal energy can keep us warm (or cool), can displace fossil fuels in any number of processes where heat is required and can be used to generate electricity anywhere on the planet.

The Earth can also act as a storage facility for heat captured from industry or from solar thermal. Storage too of energy fluids such as biogas, hydrogen and compressed air, and more is possible and is already occurring. The Earth too can store or sequester carbon to enable the energy transition away from fossil fuels. However, the scale of CO_2 disposal needs to be far larger than the handful of current, small-scale CCS projects.

Hydrogen, helium, lithium and possibly several other key metals can and are being won from geofluids. Hydrogen has yet to be proven to occur in commercial quantities beyond the one accidental discovery in Mali but this may change as exploration activity increases. It has been demonstrated that helium can be found without associated greenhouse gases, and lithium is already being extracted from several geothermal brines.

Geoscience skills and knowledge will remain critical for a world powered, heated and cooled zero-carbon energy.

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Data availability All data generated or analysed during this study are included in this published article (and, if present, its supplementary information files).

Appendix A: Helium's collateral carbon footprint

Assumptions:

- the global production of helium approximates to 54% at 0.4% helium concentration (USA, Cliffside, Russia, South Africa, Poland, China and Canada);
- the global production of helium approximates to 46% at 0.04% helium concentration (Qatar, Algeria and Australia);
- the global helium production in 2022 was 160 Mm^3;
- 1 Mm^3 of helium has a mass of 178.5 t; and
- methane and higher homologues are combusted to yield CO_2.

1 t of helium from a 0.4% source has a collateral carbon footprint of 2750 t of CO_2.

1 t of helium from a 0.04% source has a collateral carbon footprint of 27 kt of CO_2.

The annual mass of helium produced is 28.56 kt.

Carbon dioxide emitted = 0.54 × 2750 + 0.46 × 27 500 per tonne of helium = 14 135 t.

Carbon dioxide emitted for 28 560 t of helium is 404 Mt CO_2.

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