LLNL-JRNL-868312

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August 13, 2024

Applied Energy

Applied Energy 377 (2025) 124135

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Underground hydrogen storage resource assessment for the Cook Inlet, Alaska

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ARTICLE INFO

Keywords:
Hydrogen
Underground hydrogen storage
Reservoir engineering
Energy

ABSTRACT

Underground hydrogen storage will be essential to a hydrogen economy. This work focuses on the challenge of identifying and screening candidate storage systems, given the unique behavior of hydrogen in the subsurface. Here, we describe a resource assessment methodology and apply it to Alaska's Cook Inlet region. Alaska provides an interesting case study because of its abundant renewable energy resources, relatively low energy demand, and isolated electrical grid. The assessment framework considers each site's ability to (1) store a specific volume, (2) physically-contain the stored gas, and (3) limit biogeochemical activity. We estimate that reservoirs in the Cook Inlet area could theoretically store a total of 286 TWh (or 8.6 million tonnes [Mt]) in hydrogen working gas in 92 pools. This is likely sufficient to meet both local hydrogen demand and support an array of exportable products. We further identify seven pools that may be especially well-suited for hydrogen storage. Broadly, this work demonstrates a framework for regional resource assessments. On a finer scale, this work supports an early demonstration of porous–media hydrogen storage in the United States.

1. Introduction

To combat global warming, global energy systems must decarbonize. In recent years, there has been growing interest in hydrogen (H_2) as a key element of a sustainable energy portfolio. H_2 is a flexible energy carrier that can be deployed in situations where direct electrification is difficult, like long-haul shipping and industrial heating. It can also serve as a chemical feedstock for valuable products like ammonia, methanol, and sustainable shipping and aviation fuel. Lastly, it can serve as a long-duration energy storage medium, providing scalable energy storage to address imbalance in the electrical grid [1]. However, most of these H_2 applications require a reliable, dispatchable supply of H_2. This prevents intermittent renewable power sources, like wind and solar, from directly supplying the H_2. Low-cost (<$ 1/kg), high-volume (>20,000 metric tonnes [t]) H_2 storage could overcome this hurdle by buffering H_2 production and H_2 use on a seasonal basis [2].

There are several existing methods for storing H_2. Tanks, solid or liquid carriers, or other methods can store H_2 above ground. However, these methods can be expensive and energy inefficient, and have relatively small capacity for storing large quantities of H_2 [3]. Conversely, underground gas storage – practiced with natural gas for over 100 years [4] – provides significant cost and safety advantages for storing large volumes of gas, complementing smaller-scale surface storage facilities [5,6]. Salt caverns are currently used for subsurface H_2 storage, but thick salt deposits are not geographically widespread. Storing H_2 in depleted hydrocarbon reservoirs, which are more geographically widespread, may be cheaper and could provide greater storage volumes than salt caverns [7]. If such storage reservoirs are co-located with an abundant source of renewable power, transportation hub (s), and an accommodating community, they could be the kernel of a low/no-carbon industrial hub.

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https://doi.org/10.1016/j.apenergy.2024.124135
Received 19 March 2024; Received in revised form 7 June 2024; Accepted 3 August 2024
Available online 21 September 2024

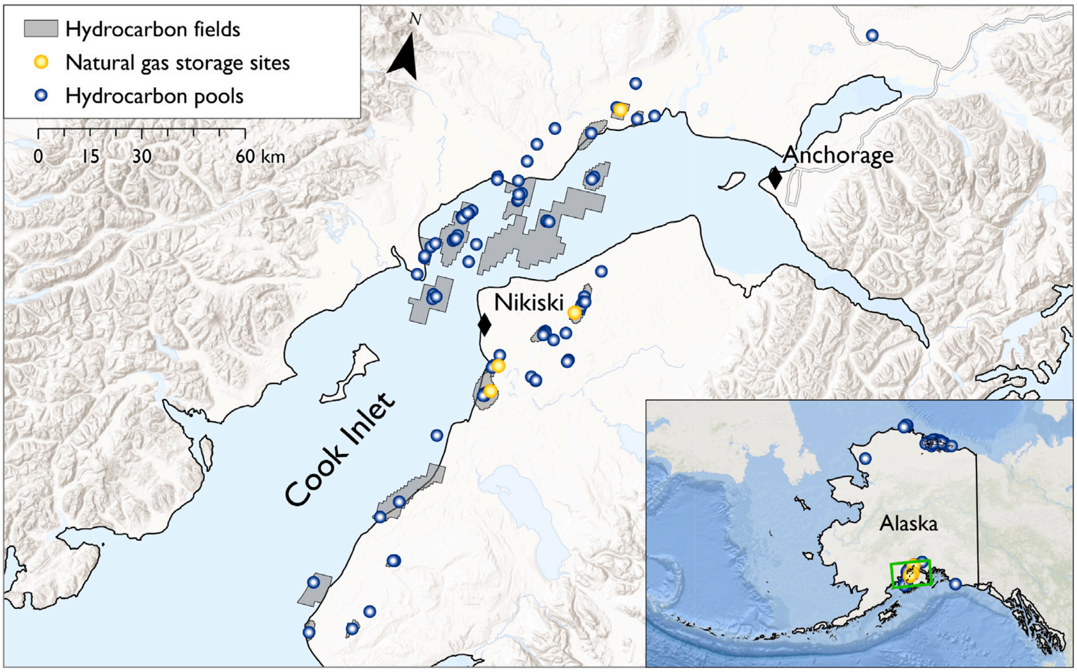

Fig. 1. Regional map of the study area. Locations of Anchorage, Nikiski, existing hydrocarbon production fields (gray polygons) and pools (blue circles), and natural gas storage sites (yellow circles) are shown.

Significant public and private investment is now being directed toward establishing "hydrogen hubs" in regions around the world where clean H_2 production, transport, storage, and end-use opportunities will be developed [8]. However, because of the relative immaturity of subsurface hydrogen storage, how and where H_2 storage sites will be selected remains a crucial question. Establishing a reproducible, adaptable framework for H_2 storage resource assessments is a key enabler for H_2 economies in the future.

In this global context, we provide a H_2 storage resource assessment for Cook Inlet, Alaska. We introduce the study region in Section 2 and explain why it is an especially compelling case study for a H_2 economy. Next, we perform a detailed assessment of H_2 storage potential in Alaska. We begin with a state-wide perspective and then focus on the Cook Inlet region in Section 3. In particular, a framework for site assessment and selection is presented. Using this framework, we identify promising storage options in the Cook Inlet region for further characterization and field testing. We conclude the paper with recommendations for future work in Section 4. Our work demonstrates a reproducible methodology for assessing and selecting favorable hydrogen storage sites and supports an early demonstration of porous–media hydrogen storage in the United States.

2. Regional context

Alaska is the largest state in the U.S. by area, yet has the second smallest population. It is isolated and remote, connected to world markets only by long-haul marine and air transport. About 70% of its 700,000+ population is inter-connected by road, rail, and electricity transmission infrastructure. The remaining 30% travel the state's undeveloped arctic/sub-arctic wilderness by air, ferry, river boat, or snow machine and rely on marine-distributed fossil fuels and local renewable power generation for electricity [9]. The state has vast natural resources, but their development is limited by the small local demand and the high cost of transporting these resources to markets further afield [9]. Some high-value resources have been exported using purpose-built infrastructure – for example: the Kennecott copper mine and railroad (1911–1938), the Cook Inlet gas fields and ammonia (1969–2008) and liquefied natural gas (LNG) (1969–2015) terminals, and the Prudhoe Bay oil field and Trans-Alaska Pipeline system (1977+). Other significant resources, such as hydro, wind, and geothermal power, are untapped and stranded from external markets. H_2 offers an opportunity to exploit these resources [10].

Alaska's Cook Inlet region, located southwest of Anchorage at the head of the Gulf of Alaska, is an especially compelling case study for future H_2 deployment (Fig. 1). First, the region is rich in natural resources. There is enormous (10's of gigawatts) untapped wind power [10] that could be used to generate H_2 and myriad geologic reservoirs that could be used to store H_2. Second, the Cook Inlet area is home to most of Alaska's people and industry, which could support H_2 end use (the city of Anchorage, at the northern end of the inlet, alone hosts ~40% of the state's population) (Fig. 1). The population could use H_2 to create synthetic fuels (eFuels) - like ammonia and sustainable aircraft fuel - to enable renewable energy exportation. Additionally, Alaskans could use H_2 domestically for heating or electricity generation [1,11]. Third, the region's low energy demand [12], high generation potential [10], and isolation relative to other parts of the world present a strong contrast to H_2 hubs that may emerge in more densely populated regions. H_2 offers the region an opportunity to exploit its resources in a low-carbon future. In the same way that commissioning the Cook Inlet LNG export terminal helped initiate the international LNG trade from the United States in 1969, developing underground H_2 storage in the Cook Inlet could have an analogous impact on national and global energy markets.

3. Hydrogen storage resource assessment

3.1. Geologic setting

Alaska exhibits a long and continuing geologic evolution. Many of the rocks in present-day Alaska formed elsewhere as distinct geologic terranes [13]. Tectonic processes carried these terranes to the

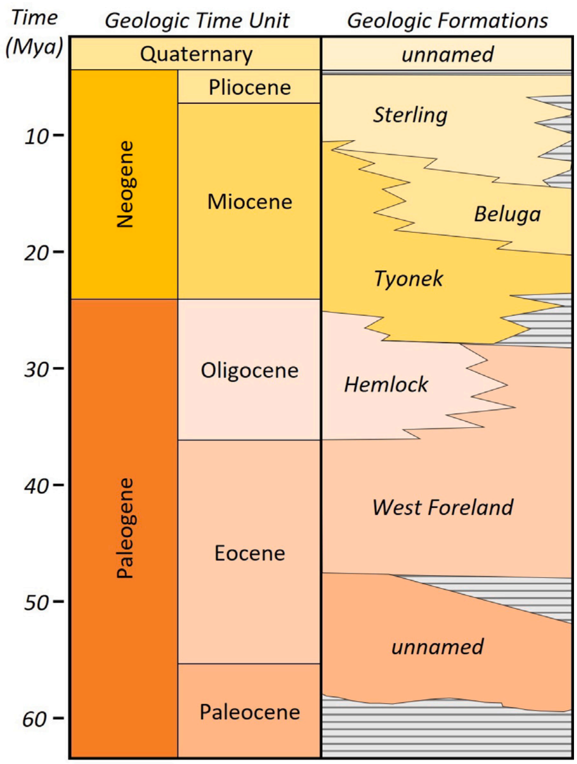

Fig. 2. Generalized stratigraphic column for Tertiary sediments in the Cook Inlet, modified after [18].

western margin of the ancient North American continent around 200 to 50 million years ago [13,14]. Subsequent terrane accretion was associated with metamorphism and igneous activity in the crust and formed sedimentary basins [13,14]. In the last 50 million years, uplift, deposition, and continued convergence controlled Alaskan geology: eroded sediments filled basins, volcanism from the subduction of the Pacific Plate formed new crust, and continued plate subduction generated earthquakes [13]. Today, sedimentary basins that evolved from the region's complex geologic history provide important resources for Alaska, the U.S., and the world.

The Cook Inlet basin formed between the topographical highs of two accreted belts and filled with marine and continental sediments over the last 200 million years [15]. The continental sediments — consisting of sand, silt, mud, and varying amounts of conglomerate — were deposited in the last 60 million years by fluvial and estuarine processes and formed hydrocarbon reservoir rocks and their associated caprocks throughout the basin [15,16]. A series of anticlines aligned northeast-southwest [17] formed the trapping structures for these reservoirs. Several large, southwest trending faults now bound the Inlet: the Bruin Bay and Castle Mountain thrust faults to the northeast and the Border Ranges fault system to the southeast [15]. Some of these faults show evidence of displacement within the last 11,000 years.

Until recently, the Cook Inlet was one of two major hydrocarbon-producing sedimentary basins in Alaska [16]. Hydrocarbon production began in the Cook Inlet in the late 1950s with the discovery of the Swanson River oil field [16]. Since then, 37 hydrocarbon-producing fields in the Cook Inlet are responsible for 7% of Alaska's historical oil production and 9% of its historical gas production [19]. The North Slope is responsible for the majority of oil and gas production in the state. Each Cook Inlet field contains several pools, which are distinct hydrocarbon accumulations in individual reservoir formations. There are 92 hydrocarbon-producing pools identified in the Cook Inlet basin, mainly distributed across five sedimentary formations. From oldest to youngest, these are the West Foreland, Hemlock Conglomerate, Tyonek, Beluga, and Sterling formations (Fig. 2). The West Foreland, Hemlock, and Tyonek formations contain significant oil-producing reservoirs. Total oil production from individual oil-producing pools in the basin ranges from near-zero to ~87.9 million m^3 (553 million barrels). The Sterling, Beluga, and Tyonek formations contain significant gas-producing reservoirs. Natural gas production to-date from individual pools in the basin ranges from near-zero to ~82.3 billion m^3 (2900 billion ft^3) [19]. Natural gas is also stored in the Sterling, Beluga, and Tyonek formations by four natural gas storage operations. The total natural gas storage capacity of these operations ranges from 0.054 to 0.92 billion m^3 (1.9 to 32.5 billion ft^3) [20]. In the future, the wealth of geological, engineering, and operational experience in the Cook Inlet basin can be leveraged for H_2 storage.

3.2. Data sources and assessment methodology

Repurposing hydrocarbon fields for H_2 storage requires technical analyses tailored to H_2's unique properties. The most favorable conditions for H2 storage are still an area of active research. However, lab experiments (e.g., [21–23]), numerical simulations (e.g., [24–26]), and field experience (e.g., [26,27]) identify properties that may determine the success or limitations of a storage system. Further, numerous studies describe workflows for selecting underground hydrogen storage sites based on these properties (e.g., [6,28–36]). Common themes from past studies are shown in Table 1. We used these themes, along with data and use-cases specific to our study region, to build a H_2 storage resource assessment framework.

Alaska benefits from extensive, publicly available datasets assembled over its history of hydrocarbon development and similar subsurface activities. These include:

- Pool-specific production history and reservoir data available from the Alaska Oil and Gas Conservation Commission [19]. Total gas, oil, and water volumes produced from and injected into each pool are reported monthly. Reservoir data (e.g., porosity, permeability, discovery pressure, temperature, depth) for each pool are reported annually. For some pools, reservoir structure maps are also available.
- Formation-specific water chemistry data available from the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database [43] and mineralogy data available from the literature [44]. Specifically, this study used the pH, salinity, and sulfate (SO_4^{2-}) concentration of formation water and the quartz, clay, calcite, and sulfur-bearing mineral content of formation mineralogies.

Publicly available datasets are most useful for identifying a few potential storage sites that are worth further investigation. This is the first step to realizing H_2 storage potential in an area of interest (i.e., Alaska). After this step, a more detailed site characterization is required to acquire more data (e.g., 3D seismic, well logs, well test data, core analysis), build static geological models of reservoir-seal systems, simulate injection/withdrawal scenarios, and perform field testing at the prospective storage site(s). Once additional data, testing, and simulations reduce uncertainty about a prospective site's ability to store and redeliver the required H_2 resource, site development and operation can proceed. This work serves as the first step, or screening, for developing H_2 storage in Alaska by identifying sites that are worth future investigation.

We evaluated potential H_2 storage sites using three metrics:

- *Storage volume*: The ability to store enough H_2 working gas to meet end-use demands.
- *Containment and storage effectiveness*: The ability to safely and effectively contain the stored H_2, considering the geologic and hydrodynamic properties of reservoirs, caprocks, and trapping mechanisms.

Table 1
Criteria suggested by the literature to minimize risks to H_2 storage. Research on these properties will grow with time, and these properties are not meant to eliminate any sites from consideration. However, for this study, these works serve as guidelines for comparing potential H_2 storage sites.

Property	Less risk	More risk
Containment and storage effectiveness		
Trap	High-relief [24]	
Caprock	Proven gas storage	Faulting
Depth	Deeper/higher pressure [37]	
Fluids in injection zone	Gas	Oil, water [38,39]
Biogeochemical compatibility		
Fluid/gas composition [23]		High carbon, sulfur, iron content
SO_4^{2-} [40]	<1250 mg/l	
Salinity	Higher for microbial growth (>1.4 M NaCl [equivalent to at least 81,682 mg/l TDS] with high temperature) [31]	>100,000 mg/l TDS for salt precipitation [41]
pH [31]		8 > pH > 6
Mineralogy [23,25,41,42]	High quartz content	Carbonate, sulfur, clay bearing minerals
Temperature	Higher for microbial growth (>75 °C with high salinity) [31]	>90 °C for abiotic reactions [22]

- *Biogeochemical compatibility*: The ability of the storage complex to limit abiotic or biotic effects on the H_2 or storage formation, considering the storage conditions, minerology, and fluid-chemistry properties.

Well integrity and related mechanical infrastructure were not considered in this study.

Through these metrics, we were able to identify a number of prospective gas pools in the Cook Inlet basin that are promising for H_2 storage. The following subsections first discuss H_2-specific considerations to each storage metric, then present the relevant data for that metric in our study region. The subsections conclude with an interpretation of these data as they relate to the potential success of a H_2 storage operation.

3.3. Storage volume

H_2 has a lower volumetric energy density than CH_4 [45], the dominant component of natural gas. This means that different volumes of each gas are required to store the same amount of energy in the subsurface. Depending on storage conditions and estimation methodology, a reservoir using H_2 can store 25%–40% of the energy that it can using CH_4 [29,37,46]. For regional H_2 storage estimates, H_2 storage volumes are estimated using static constraints, like the geometry of saline aquifers [47], cumulative gas produced and original gas in place volumes of hydrocarbon fields [48,49], and natural gas storage capacities of natural gas storage sites [50,51]. Generally, H_2 storage estimates for individual storage opportunities are thousands of TWh H_2 for aquifers, one to hundreds of TWh for hydrocarbon fields, and tenths to several TWh for natural gas fields.

H_2's unique set of use-cases determines the amount of H_2 storage required. In Alaska, H_2 could be used by the power, transportation, heating, or industrial sectors. Existing subsurface H_2 storage facilities in salt domes store between 830 t (0.028 TWh) and 3720 t (0.12 TWh) of H_2 for the industrial sector [6]. Individual natural gas storage sites, which currently supply the power and heating sectors with natural gas, could store between 42 t (0.0014 TWh) and 384,000 t (12.8 TWh) H_2 working gas [51]. Lastly, a large eFuels plant, which services the transportation sector, requires 300,000 t H_2 per year [52]. To buffer 25 days of production with H_2 storage, at least 20,000 t (0.67 TWh) of H_2 would have to be stored. Therefore, a reasonable H_2 storage working gas requirement for this study may be 20,000 t, or 0.67 TWh H_2. This value exceeds H_2 storage requirements by the industrial and transportation sectors and is similar to the H_2 storage potential provided by individual existing natural gas storage sites [51].

To investigate the ability of hydrocarbon reservoirs to meet H_2 demand in Alaska, we calculated how much H_2 working gas existing hydrocarbon pools could store. Using the temperature and discovery pressure of each pool (from [19]), we calculate H_2 and natural gas densities at reservoir conditions using the Peng-Robinson equation of state [53]. For simplicity in the density calculation, we assume the natural gas composition can be approximated as pure methane. If no values for pool temperature and original pressure are available, we assume a depth of 1 km, a pressure gradient of 0.01 MPa/m, and a temperature gradient of 0.035 °C/m. Next, by assuming that the pore space that once held natural gas is now available to host H_2, we calculate how much H_2 working gas each pool can store using a static, produced volume approach. For a given pool, we estimate the working gas energy [TWh] of hydrogen (WGE_h) as

$$WGE_h = V_n^{stp} \times \left(\frac{\rho_n^{stp}}{\rho_n^{res}}\right) \times \rho_h^{res} \times LHV_h \times WGF, \quad (1)$$

where V_n^{stp} is the net (extracted minus injected) volume [m^3] of natural gas produced from the pool at standard temperature and pressure (STP) conditions, ρ_n^{stp} is the density [kg/m^3] of natural gas at STP conditions, ρ_n^{res} is the density of natural gas at reservoir conditions, ρ_h^{res} is the density of hydrogen at reservoir conditions, LHV_h is the lower heating value of hydrogen [$=3.33 \times 10^{-8}$ TWh/kg], and WGF is the working gas fraction. Here, the working gas fraction is taken to be 0.5 for all facilities. In the future, these H_2 storage estimates must be updated with detailed numerical simulations to include dynamic, operational, and economic constraints, like H_2 injectivity, deliverability, trapping, and recovery [24,54]. However, the static methods used in this study are conducive to the limited data available for a regional scale assessment of our study area.

Detailed results of this assessment are presented in Appendix Table 2. In all of Alaska, 655 TWh (19.7 Mt) of H_2 working gas energy could be stored in hydrocarbon reservoirs. The individual working gas energies of these pools ranges from zero to 275 TWh (8.3 Mt) H_2. In the Cook Inlet specifically, 286 TWh (8.6 Mt) H_2 could be stored in existing hydrocarbon pools. The individual working gas energies of these pools range from zero to 60 TWh (1.8 Mt). Of the five main sedimentary formations in the Cook Inlet, the Sterling Formation has the greatest storage potential (111 TWh, 3.3 Mt) and the West Foreland Formation has the least (0.34 TWh, 10,204 t). Spatially, the greatest storage potential in the Cook Inlet is offshore in the North Cook Inlet,

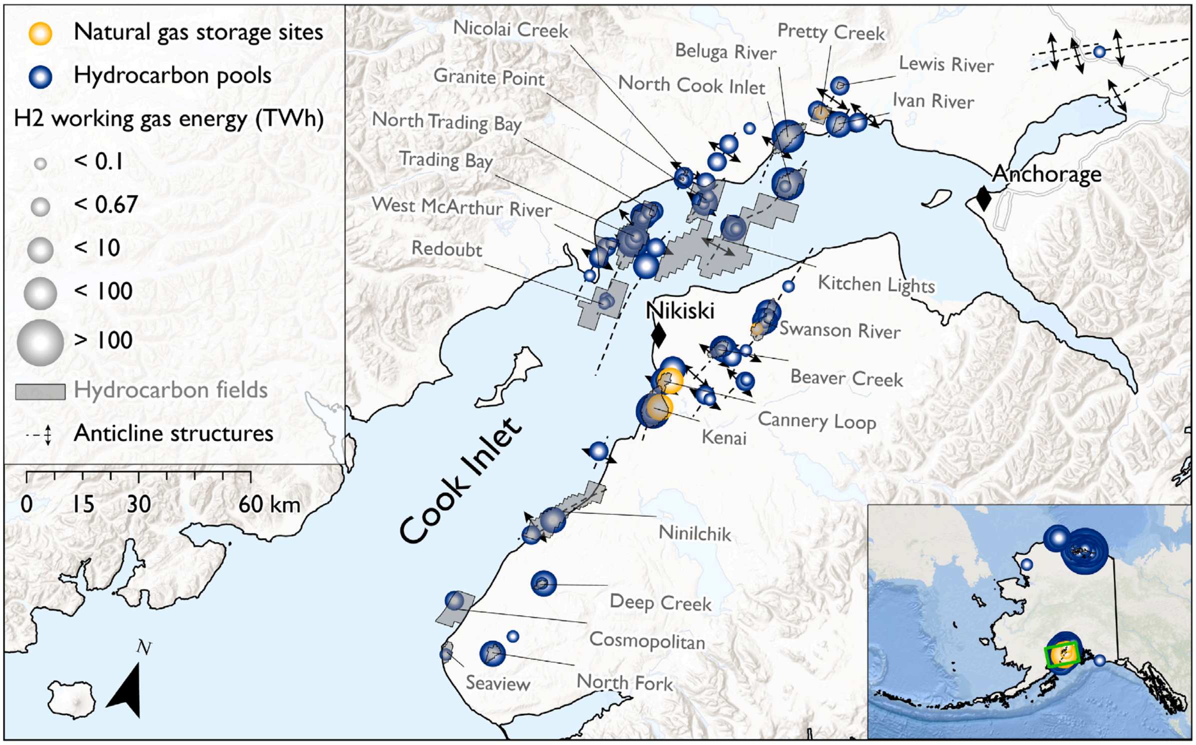

Fig. 3. The calculated H_2 working gas storage energy in hydrocarbon pools and natural gas storage sites in Alaska and (enlarged) the Cook Inlet. Hydrocarbon fields are labeled by leader lines. Cook Inlet anticlines are also displayed, from [15].

and onshore around Nikiski on the Kenai Peninsula. The distribution of individual working gas energies from this assessment (interquartile range: 0.032 TWh–1.2 TWh, median: 0.21 TWh) is most similar to that of natural gas storage sites in the U.S. [50,51]. Some high potential pools (tens to hundreds of TWh) exist, similar to H_2 storage estimates for hydrocarbon pools elsewhere in the world [48,49]. Fig. 3 shows the calculated H_2 working gas storage energy in hydrocarbon pools and natural gas storage sites in the Cook Inlet.

There are three existing natural gas storage sites on the Kenai Peninsula, around Nikiski, and one storage site onshore in the North Cook Inlet. We also report the estimated H_2 working gas energy available in these *existing* natural gas storage sites that was calculated by [51]. This study uses the reported working gas volumes for CH_4 currently stored in these reservoirs and calculates the H_2 working gas energy by assuming a replacement of CH_4 with H_2. The four existing natural gas storage sites in Alaska could together store an estimated 2.2 TWh (66,026 t) of H_2 working gas. Individual storage potential ranges from ~0.07 TWh (2100 t) to 1.35 TWh (40,516 t) H_2 working gas.

Many hydrocarbon pools (32%) in the Cook Inlet can satisfy the theoretical H_2 storage volumes required by end-use cases in Alaska. Around relatively industrialized and populous areas, large fields — such as Swanson River, Beaver Creek, Cannery Loop, and Kenai around Nikiski; and Ivan River, Beluga River, and North Cook Inlet around Anchorage — host several pools each that could meet the theorized H_2 storage demand. The Tyonek formation hosts the most of these pools (eight), followed by the Sterling (seven), Beluga (five), and Hemlock (one) formations.

To facilitate use of this storage space for H_2, cessation of hydrocarbon extraction may be beneficial because there are fewer conflicting interests over subsurface use and the operator may welcome re-purposing the pool and its wells to avoid expensive decommissioning. There are 48 pools that are either classified as inactive or reported no gas production in 2023. Eight of these – six in the Sterling Formation, one in the Tyonek Formation, and one in an unknown formation – could meet the theorized H_2 storage demand. Seven of these are located around Nikiski in the Kenai, Cannery Loop, and Beaver Creek fields. Similarly, two existing natural gas storage facilities (the Kenai Gas Field Storage and Cook Inlet Natural Gas Storage Alaska) could store an adequate amount of H_2. However, in addition to storing the required amount of H_2, a reservoir must also preserve the H_2 resource.

3.4. Containment and storage effectiveness

H_2's physical interaction with the storage system will influence the storage site's ability to safely and effectively contain it. H_2 has a lower molecular mass, density, and dynamic viscosity compared to natural gas, oil, and water [45,55]. As a result, viscosity-driven (i.e., viscous fingering) and buoyancy-driven (i.e., gravity override) fluid flow patterns could result in lost or unrecoverable H_2 [37,56]. H_2 could also have different capillary entry behavior than CH_4. This behavior, combined with H_2's low density, could affect the caprock's ability to vertically contain H_2 in the reservoir. Lastly, H_2 has a higher diffusivity and lower solubility in water than natural gas [57]. These properties govern the dissolution and diffusion of H_2 in the reservoir or caprock pore water, which can lead to lost or unrecoverable H_2. Because experience with H_2 storage in porous media is limited, it is unclear how much these processes will impact successful storage operations.

However, preliminary research indicates which factors control these risks. To mitigate complicated fluid flow processes, some results suggest storage in high-relief traps [24], gas saturated — as opposed to water or oil saturated — zones [38,39,49], and at deeper depths [37]. Next, to ensure vertical H_2 containment, a continuous, impermeable caprock is necessary. Research suggests that a caprock that once vertically limited

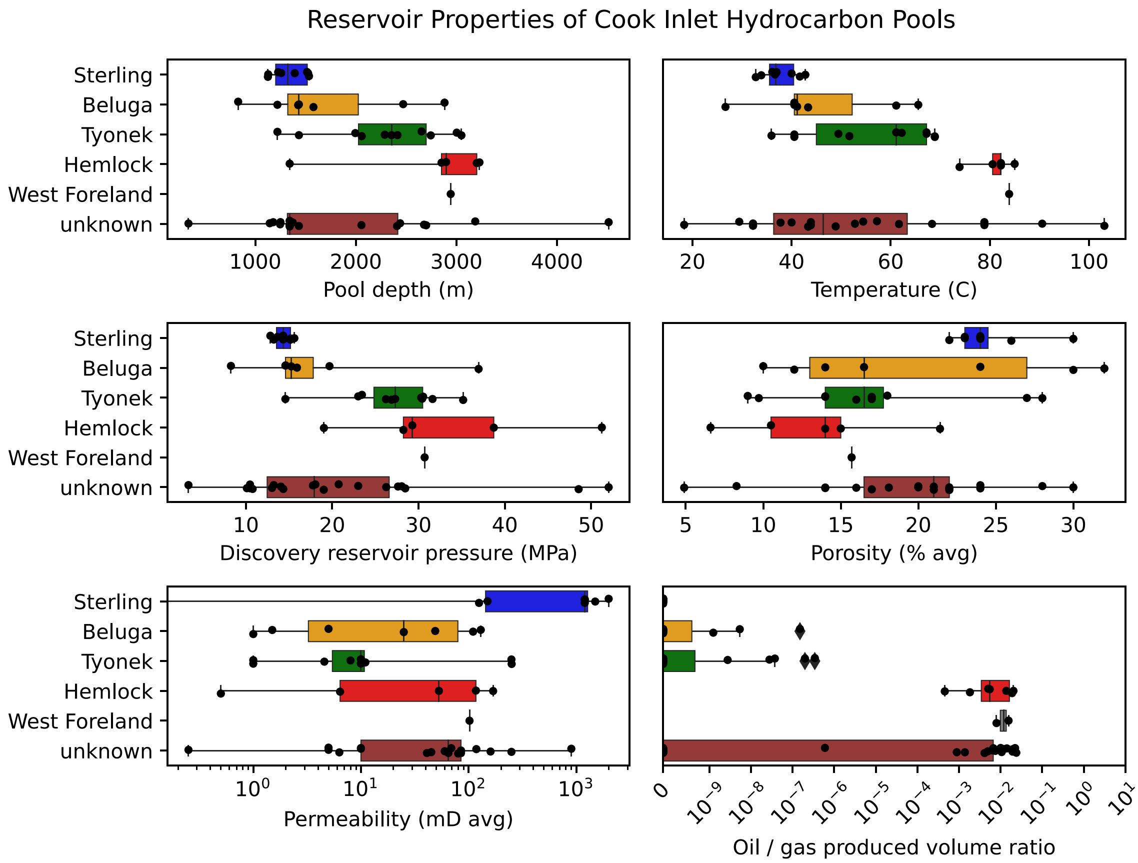

Fig. 4. Reservoir properties for Cook Inlet hydrocarbon pools. The oil/gas produced volume ratio is dimensionless and at surface conditions. *Source:* Data are from [19].

CH_4 migration through pore space will do the same for H_2 [58–60]. However, leaky flow pathways through the caprock, such as faults or wellbores, may pose greater threats for H_2 migration than CH_4 migration [37]. Lastly, diffusion and dissolution losses of H_2 could be limited by salinity, depth, and other reservoir properties [37], but are expected to be small (<0.1%–2.2% of stored H_2) and will decrease with each injection/extraction cycle [23,46,57,61]. Thus, reservoir, caprock, and trap properties are important guides for predicting H_2's physical interaction with the storage system. Table 1 shows some of the properties suggested by preliminary research to increase confidence in H_2 storage containment and effectiveness.

Caprock and trapping mechanisms vary among Cook Inlet pools. Because of the depositional architecture of the Cook Inlet basin, there is no regionally extensive, impermeable caprock overlying Cook Inlet reservoirs (Fig. 2). Mud and siltstone facies deposited on floodplains, interbedded with the fluvial and alluvial fan-deposited reservoir formations, constitute impermeable caprocks [62,63]. Caprocks in Cook Inlet hydrocarbon reservoirs have contained gas over geologic timescales (tens of millions of years), but most reservoirs were not filled to their structural spill point at discovery and there are many stacked gas accumulations, which might suggest vertical gas migration over geologic timescales [63,64]. Most of the caprocks in the Cook Inlet are strained to form anticlinal trapping structures (Fig. 3). Specifically, the trapping structures for individual pools range from hundreds of feet of four-way, domal closures with no evidence of faulting (i.e., Kenai Field Sterling Gas Pool 4, Kenai Field top Beluga Formation, North Cook Inlet Field) to three-way domal/anticlinal structures constrained by significant faulting (i.e., Swanson River Field, top Hemlock Formation) (Appendix Fig. 10). The data on trapping structures for specific pools are limited, but the fold and fault map of the Cook Inlet suggests that three-way anticlinal trapping with a varying amount of faulting is likely for all pools.

Reservoir properties like depth, pressure, oil saturation, porosity, and permeability also vary among pools (Fig. 4). Pool depths range from less than 1000 m to greater than 4000 m, and discovery pressures range from less than 10 MPa to greater than 50 MPa. Deeper formations, like the Tyonek, Hemlock, and West Foreland formations exhibit higher pressures than shallower formations, like the Sterling and Beluga formations. Oil/gas ratios (the volumetric ratio of oil produced to gas produced) range from zero to greater than three. Sterling, Beluga, and Tyonek pools mostly report close to zero oil/gas ratios, whereas Hemlock and West Foreland pools often report significantly higher oil/gas ratios. Lastly, porosities and permeabilities are greatest in the Sterling Formation, which regularly exhibits excellent porosities (>20%) and permeabilities (several darcies), though these are quite variable in the other formations. Generally, porosity decreases with depth and permeability varies from one to a couple hundred millidarcies (mD) within each formation.

Based on the evidence available for the Cook Inlet, there are no overwhelming challenges to the physical suitability of hydrocarbon reservoirs for H_2 storage. Caprocks are the source of the greatest uncertainty. The presence of gas caps in Cook Inlet hydrocarbon fields, and in some cases the successful operation of gas storage, instills confidence in each pool's ability to vertically contain buoyant gas. However, there are a few lines of evidence that suggest gas migration through the caprock over geologic timescales, such as stacked gas accumulations. On gas-storage time scales, these lines of concern may be negligible. Regardless, the data available are not sufficient for comparison among pools, and caprock characterization for each prospective storage reservoir will be necessary during development. The data for trapping mechanisms in the Cook Inlet basin confirm that individual fields, such as Kenai and North Cook Inlet, have promising trapping structures for operating a H_2 gas plume. Other pools also likely have promising domal trapping structures, although the extent of faulting needs to be characterized. Next, depth induced pressure, which might limit buoyancy-driven fluid flow patterns and therefore increase H_2 recovery, is highest in reservoirs in the Tyonek, West Foreland, and Hemlock formations. However, reservoirs in the West Foreland and Hemlock formations also have the greatest oil saturations, which could complicate these same fluid flow processes. Finally, the porosities and permeabilities are exceptional in the Sterling Formation, but sufficient in all (Fig. 4). Therefore, based on the available evidence, the Tyonek and Sterling formations may have the most favorable properties related to containment and storage effectiveness for H_2.

3.5. Biogeochemical compatibility

H_2 serves as an electron donor for a unique set of geochemical and biogeochemical reactions that can pose problems for underground H_2 storage. H_2, in the presence of CO_2, SO_4^{2-}, CO_3^{2-}, Fe^{3+}, and/or others, can react to form CH_4, HS^-, CH_3COO^-, Fe^{2+}, and/or others [22,25,61,65]. These reactions can consume and contaminate H_2, precipitate new minerals and biofilms that block flow pathways, and alter formation water chemistry, which could lead to mineral dissolution of carbonate, sulfate, clay, feldspars, and iron oxide minerals [61]. Most of these reactions can occur abiotically but are catalyzed and sped up by hydrogenotrophic bacteria [26]. Additionally, H_2 could become unrecoverable through sorption to clay minerals.

Current research shows that the risk posed by biogeochemical reactions could be significant but is somewhat uncertain. Considering only abiotic reactions, numerical simulations and experimental studies [22,26] reported negligible H_2 losses at storage conditions and timescales in sandstones. In calcite-rich rocks, however, abiotic hydrogen-calcite reactions reduced porosity by almost half [66]. While also considering microbial processes, simulation studies [31,46] have shown relatively small gas consumption (0.01–3.7% of stored H_2), whereas experimental studies [21,42] reported microbial processes converting or consuming 32%–40% of stored H_2. Field experience, at a test site in Czechia, storing gas with significant H_2 content observed up to 17% of H_2 consumed, likely by microbial activity [31].

To mitigate these effects, ongoing work aims to identify influential storage properties for biogeochemical interactions. Broadly, some studies suggest storing H_2 in reservoirs with low carbon, sulfur, and iron-content in formation gas and water [23,40] and low carbonate, sulfur, and clay-bearing mineral content, and high quartz content in the reservoir mineralogy [23,31,41,42]. Additionally, higher temperatures and salinities, non-circumneutral pH values, and lower oil saturations could discourage microbial species growth [25,31]. However, these optimal storage properties are balanced by other factors. For example, higher salinities could risk salt precipitation in the reservoir [41], which could inhibit permeability during pressure changes in gas storage operations, and higher temperatures could increase the rate of abiotic reactions [22]. Regardless, minerology, water chemistry, and storage conditions are main factors that can influence biogeochemical reactions during H_2 storage. Table 1 shows some of the properties/values suggested by preliminary research to decrease biogeochemical risks. For the Cook Inlet basin, these properties vary among sedimentary formations.

A thorough analysis of 238 Cook Inlet sandstone samples in [44] provided mineralogical data, briefly summarized here and displayed in Fig. 5. Broadly, the Cook Inlet formations are poorly to medium sorted feldspathic litharenites to litharenites. The West Foreland, Beluga, and Sterling formations generally have high percentages of lithic fragments (>60%) and low percentages of quartz (<40%). The rock fragments in the Beluga and West Foreland formations are clay-rich, whereas the rock fragments in the Sterling Formation are largely felsic-intermediate volcanic clasts. The Hemlock and Tyonek formations are generally richer in quartz (>60%) and have lower percentages of lithic fragments (<40%) than the other formations. All of the reservoir formations show little or no calcite, and no sulfur-containing minerals (pyrite and gypsum).

The USGS National Produced Waters Geochemical Database contains the most comprehensive water chemistry data available for the Cook Inlet, displayed in Fig. 6 [43]. Waters produced from Cook Inlet formations generally show SO_4^{2-} concentrations <1000 mg/L, salinities between 10,000–30,000 mg/l TDS, and pH between 6–10. However, because of the data resolution, it is difficult to compare the water chemistry between formations.

Lastly, the oil to gas produced volume ratio and temperature of hydrocarbon pools are displayed in Fig. 4. Oil to gas produced volume ratios (used as a metric of oil saturation) in Cook Inlet pools are greatest in the Hemlock and West Foreland formations. Temperatures of Cook Inlet hydrocarbon pools range from 18–103 °C, with most values falling around 44 °C. Because of the Cook Inlet's stratigraphy, temperatures in the Tyonek, Hemlock, and West Foreland formation reservoirs are, on average, >60 °C, whereas temperatures in the Beluga and Sterling formation reservoirs are lower. Only one pool (Beaver Creek Oil) reports temperatures >90 °C.

Based on the available data, some reservoirs show promising characteristics to limit biogeochemical interactions with H_2. The fact that all reservoir formations exhibit low or no calcite content and no sulfur-containing minerals is encouraging. The sulfate content of Cook Inlet sedimentary formations also looks to be compatible with H_2 storage, based on preliminary research (Fig. 6). Further, the relatively quartz-rich, clay-poor Tyonek and Hemlock formations and clay-poor Sterling Formation may have less reactive mineralogies than the other reservoirs (Fig. 5). Additionally, the Sterling, Beluga, and Tyonek pools host the least amount of oil, which might help limit microbial reactions in these pools. In contrast, the temperatures, salinities, and pH ranges of Cook Inlet hydrocarbon reservoirs might be conducive to microbial growth. All reservoirs fall below or outside the temperatures, salinities, and pH ranges that may be sterile to all hydrogenetrophic bacteria. But, the higher temperatures in the Tyonek, West Foreland, and Hemlock formations may discourage growth of some species of hydrogenetrophic bacteria. Overall, based on public data and current research, the Sterling and Tyonek are the most favorable formations for limiting biogeochemical interactions with H_2.

3.6. Integrated findings

On a formation scale, the Sterling and Tyonek formations are the most attractive options for H_2 storage in the Cook Inlet basin. Compared to other sedimentary formations, the Sterling Formation boasts high porosities and permeabilities, low clay content, low/no oil saturation, and suitable fluid chemistry, and demonstrates effective natural gas storage. The Tyonek Formation, relative to other Cook Inlet sandstones, has sufficient porosities and permeabilities, high quartz and low clay content, suitable fluid chemistry, higher temperatures and pressures, and low oil saturations, and demonstrates effective natural gas storage. Because there are many fields that produce from the Sterling and Tyonek reservoirs in the Cook Inlet, we can narrow our focus to a pool scale.

On a pool scale, seven pools stand out as especially promising for H_2 storage development in the Cook Inlet. We consider pools that (1) meet the theoretical required H_2 storage resource and (2) may be available for use — because hydrocarbon production has stopped — as the most prospective pools for H_2 storage. Four of these pools are in the Kenai Field (Sterling 3, 4, 5.1, and 6), two are in the Cannery Loop Field

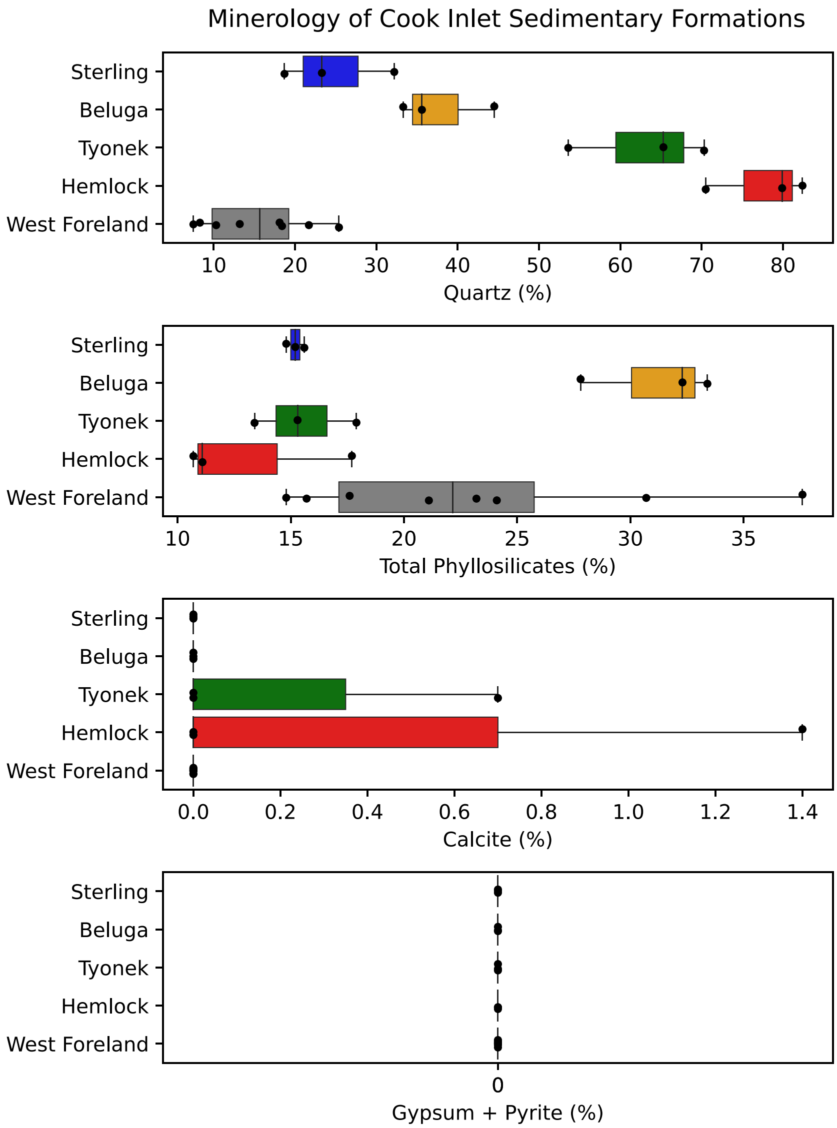

Fig. 5. Mineralogical data for Cook Inlet reservoir formations.
Source: Data are from [44].

(Upper Tyonek Gas and Sterling Undefined), and one is in the Beaver Creek Field (Sterling Gas). All of these fields are onshore and close to potential demand centers.

Integrating our scopes of analysis shows that the Tyonek and Sterling reservoirs in the Kenai, Cannery Loop, and Beaver Creek fields (which comprise the Sterling 3, 4, 5.1, and 6 pools in the Kenai field, the Upper Tyonek and Sterling Undefined pools in the Cannery Loop field, and the Sterling pool in the Beaver Creek Field) are worth further investigation (Fig. 7). Compared to other pools, these pools exhibit (1) favorable working gas energies, depletion metrics, and locations to satisfy demand in the Cook Inlet, and (2) favorable mineralogies, fluid chemistries, and reservoir properties to ensure safe and effective stewardship of the H_2 resource.

These pools can offer unique favorable attributes when compared to one another. For example, the Kenai Sterling pools exhibit higher porosities and permeabilities, whereas the Cannery Loop Tyonek pool is deeper and hotter. A comparison of properties among these pools is shown in Fig. 8.

Our analysis also highlights specific areas of future investigation. For example, the Sterling Formation's relatively shallow depth, low temperatures, and volcanic mineralogy might be conducive to microbial and geochemical effects. Therefore, it is necessary to survey the microbial community and reactivity of Sterling reservoirs. Conversely, the variable porosities and permeabilities and presence of calcite cement in Tyonek reservoirs may limit injectivity/extractability and risk geochemical reactions. Therefore, the performance and reactivity of the Tyonek reservoirs should be characterized. More broadly, the stacked nature of pools in the Kenai and Cannery Loop fields requires a few additional considerations. First, the caprock in each pool must prevent leakage over human time scales. Second, leakage pathways provided by the extensive well penetrations through each formation of interest must be scrutinized. All avenues of investigation discussed in this section are standard during site characterization and development [67].

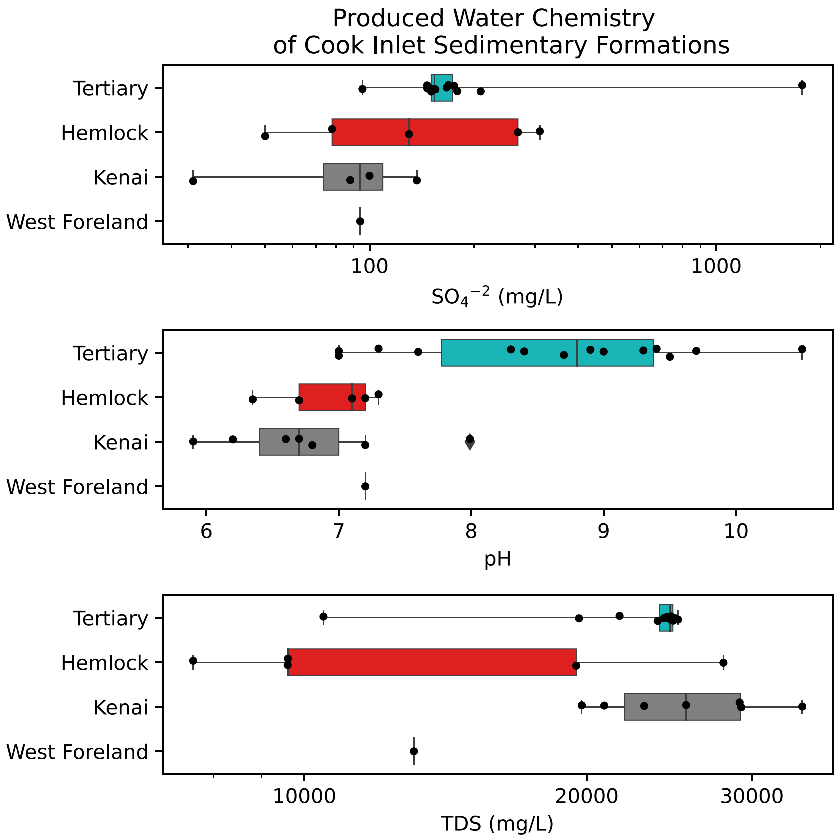

Fig. 6. Produced water chemistry data for Cook Inlet reservoir formations. The "Tertiary" and "Kenai" designations encompass Tertiary sediments, which make up reservoir formations in the Cook Inlet.
Source: Data are from [43].

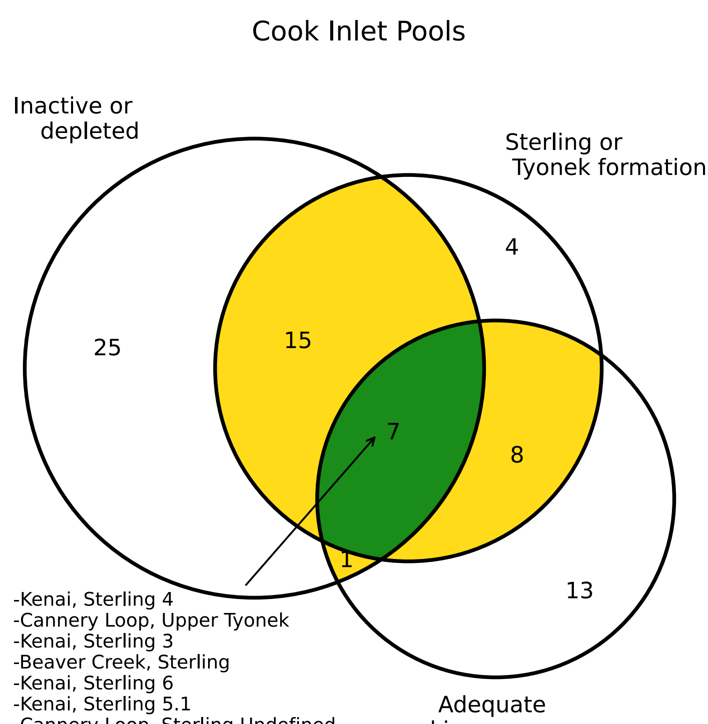

Fig. 7. Venn diagram of selection method for identifying potential suitable pools for H_2 storage. The Sterling and Tyonek formations are preferred for biogeochemical and physical compatibility. Pools that are depleted or inactive and have adequate working gas energy are preferred for energy storage compatibility.

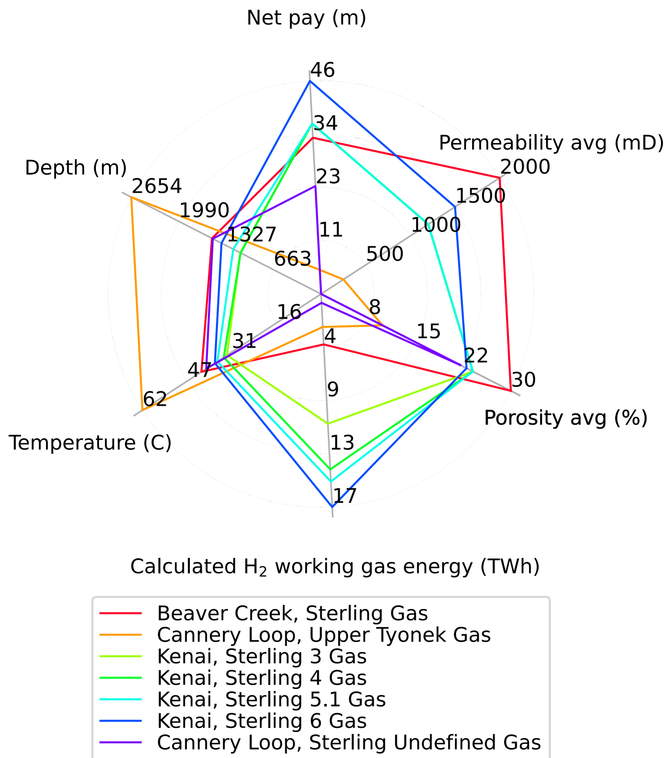

Fig. 8. Selected pool properties for the seven hydrocarbon pools in the Cook Inlet that our analysis identified as especially promising for H_2 storage. For more data on each individual pool, see [19].

4. Conclusions and recommendations

In this study, we demonstrated a reproducible methodology for H_2 storage resource assessments, a key enabler for H_2 deployment. Our analysis used data on reservoir properties, fluid chemistry, and mineralogy to identify prospective sites for H_2 storage in the Cook Inlet, Alaska. Broadly, we find that 29 out of 92 hydrocarbon pools, and two natural gas storage pools, could meet a theorized H_2 storage demand in the Cook Inlet if they were repurposed for H_2 storage. Aditionally, based on available data on reservoir properties, fluid chemistry, and mineralogy, the Tyonek and Sterling sedimentary formations are the most promising for safe and effective H_2 storage. Within these formations, the pools most likely to meet storage demand and be available for development are the (1) Cannery Loop, Upper Tyonek ; (2) Cannery Loop, Sterling Undefined ; (3) Kenai, Sterling 6; (4) Kenai, Sterling 4; (5) Kenai, Sterling 5.1; (6) Kenai, Sterling 3; and (7) Beaver Creek, Sterling pools. The next step is to build on existing data for these pools with additional data collection, modeling, and testing to narrow the selection further and develop these pools for H_2 storage.

To further ensure the prospectivity for H_2 storage of the seven short-listed hydrocarbon pools, several steps are required during characterization. Integration of geological data from well logs and available seismic data can be used to build static geological models for each pool that can then be subjected to simulations of possible field development scenarios. Assuming data of sufficient quality are available for these purposes, the most promising field could advance to a field test of hydrogen injection. This should involve the drilling of a new characterization well to collect a full suite of modern petrophysical and geochemical well logs (for calibrating geological models), core samples from the reservoir and caprock (for routine, special, and biochemical core analysis), and well test data (for calibrating simulation outcomes), as well as the collection of a modern 3D seismic survey to map subsurface stratigraphic architecture, structures, and faults. Once the test injection is complete, rotary sidewall cores should be obtained to characterize formation alteration caused during hydrogen injection/extraction. The integration of these new data into the pre-existing geological model for the reservoir should provide a firm foundation for reducing uncertainty around risk characterization for subsurface hydrogen storage in Cook Inlet fields. In doing so, Alaska could pioneer H_2 storage in porous media in the United States, establishing its commercial viability.

CRediT authorship contribution statement

Leon Hibbard: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Joshua A. White:** Writing – review & editing, Writing – original draft, Supervision, Resources, Project administration, Investigation, Funding acquisition, Conceptualization. **David G. Clarke:** Writing – review & editing, Investigation, Data curation, Conceptualization. **Simon Harrison:** Writing – review & editing, Writing – original draft, Investigation, Data curation, Conceptualization. **Richard A. Schultz:** Writing – review & editing, Conceptualization. **Franek Hasiuk:** Writing – review & editing, Visualization. **Angela Goodman:** Writing – review & editing, Supervision, Resources, Project administration, Funding acquisition, Conceptualization. **Nicolas Huerta:** Supervision, Resources, Project administration, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

Acknowledgments

The authors wish to thank the staff at the Alaska Oil and Gas Commission, in particular, Steve Davies, Meredith Guhl, Dave Roby, for assistance with data gathering efforts. The authors also wish to thank Julia Camargo at PNNL for technical review and Greg Lackey at NETL for data gathering efforts. Funding for LH, JAW, AG, RAS, FH, and NH was provided by the U.S. Department of Energy, Office of Fossil Energy and Carbon Management, through the Subsurface Hydrogen Assessment, Storage, and Technology Acceleration (SHASTA) project. Funding for DC and SH was provided by Alaska Marine Power LLC, United States. Portions of this work were performed under the auspices of the U.S. Department of Energy by Lawrence Livermore National Laboratory under contract DE-AC52-07-NA2734, by Pacific Northwest National Laboratory, United States under contract DE-AC05-76RL01830, and by the National Energy Technology Laboratory, Research and Innovation Center, United States.

Appendix

See Table 2, Figs. 9 and 10.

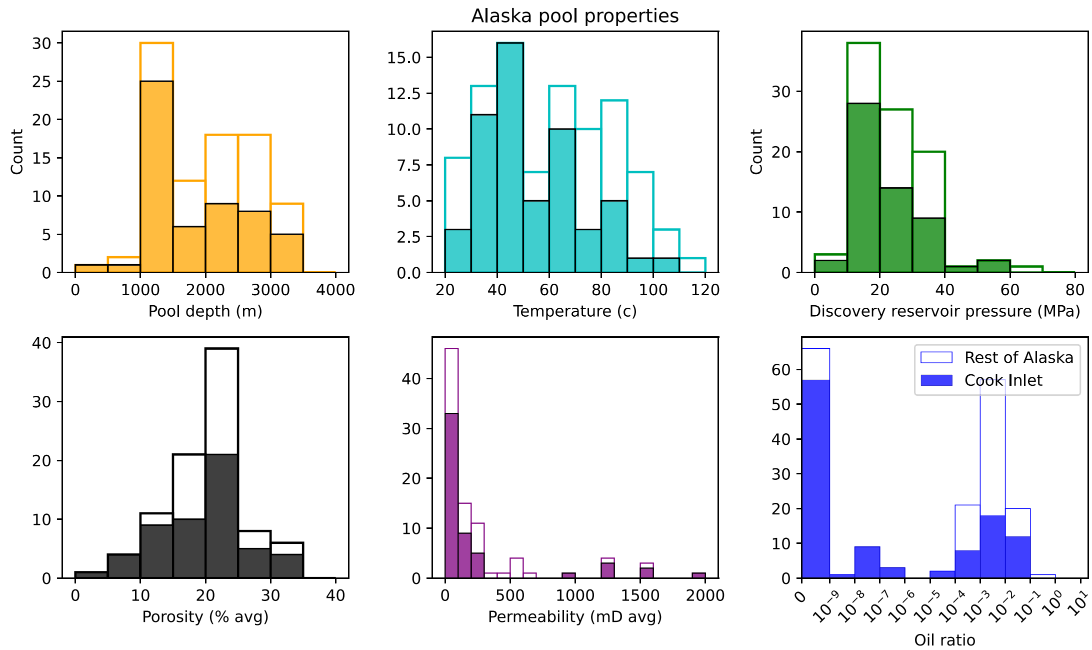

Fig. 9. Properties for all hydrocarbon pools in Alaska [19].

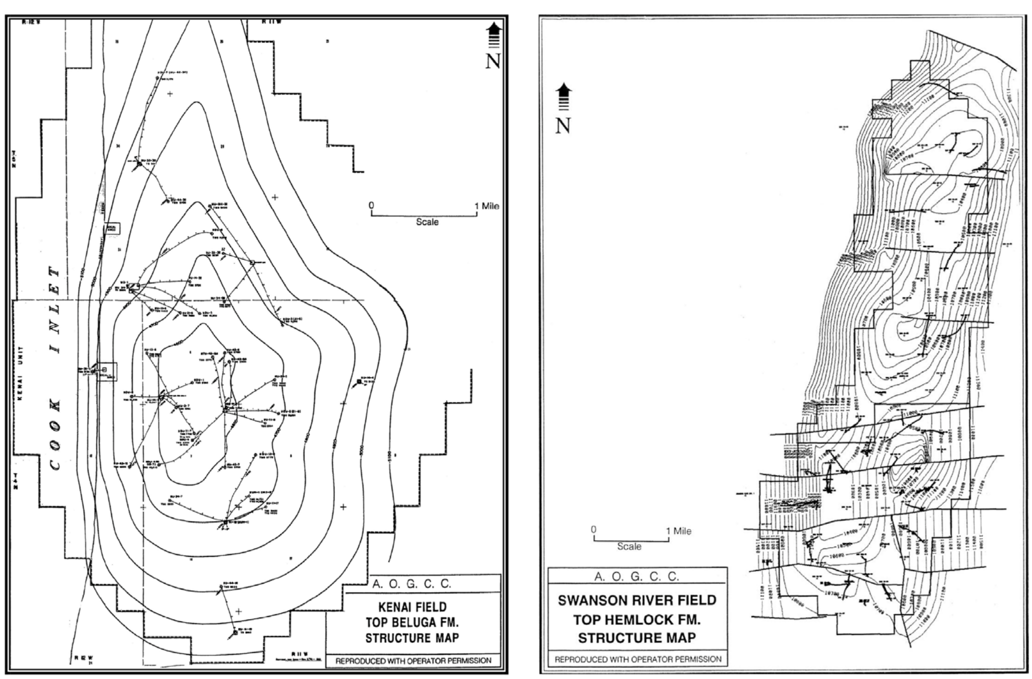

Fig. 10. Examples of (left) four-way (Kenai Field, top Beluga reservoir [19]) and (right) three-way closures (Swanson River Field, top Hemlock formation [19]) in Cook Inlet hydrocarbon fields.

Table 2
Properties for all hydrocarbon pools in the Cook Inlet [19]. Key: TOP = Total Oil Production, NGP = Net Gas Production, MGPR = Max Gas Production Rate, PRR = Production Rate Ratio (2023/Max), OR = Oil Ratio (gas produced/oil produced volume), WGE = H_2 Working Gas Energy.

	Field, PoolName	Reservoir	Poro (%)	Perm (mD)	Depth (m)	Temp (C)	Pressure (MPa)	Net Pay (m)	Status	TOP (m^3)	NGP (m^3)	MGPR (m^3/month)	PRR (–)	OR (–)	WGE (TWh)
0	ALBERT KALOA, UNDEFINED GAS	Unknown	nan	nan	nan	nan	nan	nan	nan	0.00e+00	1.02e+08	4.87e+06	0.00e+00	0.00e+00	0.12
1	BEAVER CREEK, BEAVER CREEK OIL	Unknown	14.00	5.00	4514.00	103.10	52.03	30.50	Producing	1.15e+06	8.10e+07	1.66e+06	0.07	0.01	0.11
2	BEAVER CREEK, BELUGA GAS	Beluga	10.00	5.00	2470.50	61.11	19.69	15.25	Producing	0.00e+00	2.87e+09	1.10e+07	0.56	0.00e+00	3.29
3	BEAVER CREEK, STERLING GAS	Sterling	30.00	2000.00	1525.00	41.67	15.16	33.55	Producing	0.00e+00	3.68e+09	1.78e+07	0.00e+00	0.00e+00	4.10
4	BEAVER CREEK, TYONEK GAS	Tyonek	14.00	10.00	3003.34	68.89	30.32	13.72	Producing	219.88	6.42e+08	9.71e+06	0.13	3.42e−07	0.76
5	BELUGA RIVER, STERLING-BELUGA GAS	Beluga	24.00	49.00	1220.00	41.11	15.26	32.33	Producing	0.00e+00	4.01e+10	3.18e+07	0.17	0.00e+00	44.64
6	BIRCH HILL, UNDEFINED GAS	Unknown	nan	nan	nan	nan	nan	nan	nan	0.00e+00	1.85e+06	1.85e+06	0.00e+00	0.00e+00	2.20e−03
7	GRANITE PT, HEMLOCK UNDEF OIL	Hemlock	6.60	0.50	3202.50	85.00	51.24	76.25	Producing	3.55e+05	6.46e+07	1.33e+06	0.00e+00	5.49e−03	0.08
8	GRANITE PT, MIDDLE KENAI OIL	Unknown	14.00	10.00	2677.90	78.89	28.05	129.62	nan	2.49e+07	3.99e+09	5.31e+06	0.12	6.25e−03	4.75
9	GRANITE PT, UNDEFINED GAS	Unknown	22.00	0.25	1246.84	37.78	13.02	41.17	Prod. Intermittent	0.00e+00	1.01e+07	6.30e+05	0.00e+00	0.00e+00	0.01
10	IVAN RIVER, UNDEFINED GAS	Unknown	20.00	80.00	2409.50	52.78	28.46	17.08	Producing	0.00e+00	2.73e+09	1.75e+07	0.16	0.00e+00	3.12
11	CANNERY LOOP, BELUGA GAS	Beluga	16.50	25.00	1578.38	43.33	15.92	61.00	Producing	16.53	3.07e+09	1.28e+07	0.11	5.38e−09	3.43
12	CANNERY LOOP, TYONEK D GAS	Tyonek	17.00	4.57	3050.00	67.22	31.63	10.67	Inactive	0.00e+00	9.14e+07	1.32e+07	0.07	0.00e+00	0.11
13	CANNERY LOOP, UPPER TYONEK GAS	Tyonek	9.71	250.00	2653.50	62.22	35.17	5.18	Producing	62.64	2.25e+09	1.31e+07	0.00e+00	2.78e−08	2.68
14	KENAI, BELUGA UNDEF GAS	Beluga	14.00	1.00	1433.81	40.56	14.57	54.90	nan	0.00e+00	3404.71	3404.71	0.00e+00	0.00e+00	3.80e−06
15	KENAI, BELUGA/UP TYONEK GAS	Tyonek	14.00	1.00	1433.81	40.56	14.57	54.90	Producing	457.72	1.22e+10	1.63e+07	0.08	3.74e−08	13.64
16	KENAI, STERLING 3 GAS	Sterling	24.00	1200.00	1128.50	32.78	12.83	36.60	Inactive	0.00e+00	9.53e+09	1.41e+07	0.04	0.00e+00	10.56
17	KENAI, STERLING 4 GAS	Sterling	24.00	1200.00	1125.45	33.89	13.22	36.60	Inactive	0.00e+00	1.29e+10	1.32e+07	0.06	0.00e+00	14.28
18	KENAI, STERLING 5.1 GAS	Sterling	24.00	1200.00	1227.62	36.11	13.65	36.60	Inactive	0.00e+00	1.38e+10	1.53e+07	0.00e+00	0.00e+00	15.27
19	KENAI, STERLING 5.2 GAS	Sterling	23.00	150.00	1258.12	36.67	14.32	16.47	nan	0.00e+00	1.42e+09	9.64e+06	0.09	0.00e+00	1.57
20	KENAI, STERLING 6 GAS	Sterling	23.00	1500.00	1392.33	36.98	14.32	45.75	Producing	0.00e+00	1.57e+10	1.35e+07	0.00e+00	0.00e+00	17.34
21	KENAI, TYONEK GAS	Tyonek	17.00	10.00	2745.00	68.89	30.43	36.60	Producing	1429.93	7.22e+09	2.80e+07	0.06	1.98e−07	8.53
22	LEWIS RIVER, UNDEFINED GAS	Unknown	22.00	45.00	1433.50	43.89	19.02	13.72	Producing	0.00e+00	4.85e+08	1.27e+07	0.13	0.00e+00	0.54
23	MCARTHUR RIVER, HEMLOCK OIL	Hemlock	10.50	53.00	2851.75	82.22	29.28	88.45	Producing	8.78e+07	6.41e+09	6.63e+06	0.04	0.01	7.69
24	MCARTHUR RIVER, MIDDLE KENAI G OIL	Unknown	18.10	65.00	2699.25	78.89	27.62	30.50	Producing	1.13e+07	1.12e+09	2.37e+06	0.20	0.01	1.34
25	MCARTHUR RIVER, MIDDLE KENAI GAS	Unknown	22.00	900.00	1372.50	48.89	20.74	114.38	Producing	0.00e+00	3.62e+10	4.47e+07	0.06	0.00e+00	40.43
26	MCARTHUR RIVER, UNDEFINED OIL	Unknown	4.90	6.30	3187.25	90.56	48.55	45.75	nan	5.29e+04	4.98e+06	3.97e+05	0.00e+00	0.01	6.43e−03
27	MCARTHUR RIVER, WEST FORELAND OIL	West Foreland	15.70	102.00	2943.25	83.89	30.71	30.50	Producing	4.35e+06	2.80e+08	1.88e+06	0.08	0.02	0.34
28	MIDDLE GROUND SHOAL, MIDDLE GRND SHOAL GAS	Unknown	nan	nan	1143.75	54.44	10.11	15.25	Inactive	0.00e+00	4.78e+08	5.39e+06	0.00e+00	0.00e+00	0.57
29	MIDDLE GROUND SHOAL, MIDDLE GRND SHOAL OIL	Unknown	8.28	10.00	2440.00	68.33	26.26	402.60	nan	3.26e+07	2.70e+09	3.93e+06	0.00e+00	0.01	3.16
30	MOQUAWKIE, UNDEFINED GAS	Unknown	nan	nan	nan	nan	nan	nan	nan	0.00e+00	1.44e+08	4.94e+06	0.00e+00	0.00e+00	0.17
31	NICOLAI CREEK, NORTH UNDEF UPPER TYONEK GAS	Tyonek	nan	nan	nan	nan	nan	nan	Producing	0.00e+00	1.12e+08	3.29e+06	0.00e+00	0.00e+00	0.13
32	NINILCHIK, BELUGA-TYONEK GAS	Tyonek	18.00	10.00	1220.00	40.56	23.01	135.12	Producing	0.00e+00	7.74e+09	1.90e+07	0.46	0.00e+00	8.49
33	NORTH COOK INLET, TERTIARY GAS	Unknown	28.00	160.00	1250.50	29.44	14.06	102.78	nan	0.00e+00	5.56e+10	4.12e+07	0.11	0.00e+00	60.34
34	NORTH FORK, TYONEK GAS	Tyonek	nan	nan	nan	nan	nan	nan	Producing	0.00e+00	6.97e+08	6.34e+06	0.12	0.00e+00	0.83
35	PRETTY CREEK, UNDEFINED GAS	Unknown	22.00	118.00	1178.52	32.22	13.23	18.30	nan	0.00e+00	2.73e+08	6.27e+06	2.51e−03	0.00e+00	0.30
36	REDOUBT SHOAL, UNDEFINED OIL	Unknown	nan	nan	nan	nan	nan	nan	Producing	9.44e+05	3.95e+07	3.22e+05	0.35	0.02	0.05
37	STERLING, BELUGA UNDEFINED GAS	Beluga	nan	nan	nan	nan	nan	nan	nan	0.00e+00	1.24e+07	8.78e+05	0.00e+00	0.00e+00	0.01
38	STERLING, STERLING UNDEFINED GAS	Sterling	26.00	125.00	1534.15	42.78	15.61	7.62	Inactive	0.00e+00	1.08e+08	1.92e+06	0.00e+00	0.00e+00	0.12
39	STERLING, TYONEK UNDEFINED GAS	Tyonek	nan	nan	nan	nan	nan	nan	nan	0.00e+00	4.01e+06	2.09e+06	0.00e+00	0.00e+00	4.77e−03
40	STUMP LAKE, UNDEFINED GAS	Unknown	24.00	5.00	2055.70	43.33	23.01	27.75	nan	0.00e+00	1.89e+08	5.25e+06	0.00e+00	0.00e+00	0.21
41	SWANSON RIVER, HEMLOCK OIL	Hemlock	21.40	117.00	3229.34	82.22	38.72	40.56	Producing	3.76e+07	5.08e+08	3.16e+07	4.09e−03	4.56e−04	0.63
42	SWANSON RIVER, STERLING/UPPER BELUGA GAS	Beluga	32.00	129.75	829.60	26.67	8.26	5.18	nan	0.00e+00	1.28e+09	8.37e+06	0.17	0.00e+00	1.49
43	SWANSON RIVER, TYONEK GAS	Tyonek	27.00	251.25	1994.70	35.94	30.54	5.58	Producing	1.91	6.93e+08	7.00e+06	0.73	2.75e−09	0.78
44	SWANSON RIVER, UNDEFINED OIL	Unknown	nan	nan	nan	nan	nan	nan	nan	8146.33	9.19e+06	6.96e+06	0.00e+00	8.86e−04	0.01
45	TRADING BAY, G-NE/HEMLOCK-NE OIL	Hemlock	14.00	6.40	2897.50	73.89	28.25	94.55	nan	3.76e+06	1.84e+08	1.26e+06	0.00e+00	0.02	0.22
46	TRADING BAY, HEMLOCK OIL	Hemlock	15.00	169.00	1342.00	80.56	19.04	43.31	nan	2.60e+06	5.15e+08	3.03e+06	0.03	5.05e−03	0.61
47	TRADING BAY, MIDDLE KENAI B OIL	Unknown	24.00	85.00	1342.00	40.00	10.78	135.72	Producing	9.30e+05	1.89e+08	1.12e+06	0.08	4.93e−03	0.22
48	TRADING BAY, MIDDLE KENAI C OIL	Unknown	20.00	69.00	1342.00	43.89	14.33	115.90	Producing	3.61e+06	4.82e+08	3.15e+06	0.02	7.49e−03	0.54
49	TRADING BAY, MIDDLE KENAI D OIL	Unknown	16.00	41.00	1342.00	57.22	17.76	75.03	Producing	4.89e+06	7.30e+08	5.62e+06	0.01	6.70e−03	0.83
50	TRADING BAY, MIDDLE KENAI E OIL	Unknown	17.00	60.00	1342.00	61.67	18.04	44.23	Producing	1.44e+06	2.20e+08	3.45e+06	0.01	6.53e−03	0.25
51	TRADING BAY, UNDEFINED GAS	Unknown	21.00	85.00	1342.00	32.22	10.47	33.55	nan	0.00e+00	1.62e+08	4.60e+06	0.00e+00	0.00e+00	0.19
52	TRADING BAY, UNDEFINED OIL	Unknown	21.00	85.00	1342.00	32.22	10.47	33.55	Producing	2.80e+05	6.80e+07	1.83e+06	0.05	4.12e−03	0.08
53	TRADING BAY, W FORELAND OIL	West Foreland	nan	nan	nan	nan	nan	nan	Inactive	1.17e+04	1.47e+06	7.54e+04	0.02	7.98e−03	1.75e−03
54	W FORK, STERLING A GAS	Sterling	nan	nan	nan	nan	nan	nan	Inactive	0.00e+00	3.49e+07	2.65e+06	0.00e+00	0.00e+00	0.04
55	W FORK, STERLING B GAS	Sterling	nan	nan	nan	nan	nan	nan	Inactive	0.00e+00	4.08e+07	4.35e+06	0.00e+00	0.00e+00	0.05
56	W FORK, UNDEFINED GAS	Unknown	nan	nan	nan	nan	nan	nan	Inactive	0.00e+00	9.37e+07	2.74e+06	0.00e+00	0.00e+00	0.11
57	W MCARTHUR RIV, W MCARTHUR RIV OIL	Unknown	nan	nan	nan	nan	nan	nan	Producing	2.41e+06	1.08e+08	5.33e+05	0.13	0.02	0.13
58	BEAVER CREEK, STERLING UNDEFINED GAS	Sterling	nan	nan	nan	nan	nan	nan	nan	0.00e+00	2.61e+07	2.78e+06	0.00e+00	0.00e+00	0.03
59	DEEP CREEK, HV BELUGA/TYONEK GAS	Tyonek	28.00	1.00	2414.07	67.22	26.22	10.06	Producing	0.00e+00	1.18e+09	4.62e+06	0.27	0.00e+00	1.38
60	DEEP CREEK, UNDEFINED GAS	Unknown	30.00	250.00	335.50	18.33	3.34	12.81	Producing	0.00e+00	5.57e+07	4.04e+06	0.00e+00	0.00e+00	0.07
61	GRANITE PT, GRANITE PT GAS	Unknown	nan	nan	nan	nan	nan	nan	nan	0.00e+00	2.88e+07	4.35e+05	0.28	0.00e+00	0.03
62	HANSEN, HANSEN OIL	Unknown	nan	nan	nan	nan	nan	nan	Producing	3.56e+05	2.56e+08	9.02e+06	0.05	1.39e−03	0.30
63	KASILOF, TYONEK UNDEFINED GAS	Tyonek	nan	nan	nan	nan	nan	nan	nan	0.00e+00	1.23e+08	1.29e+07	0.00e+00	0.00e+00	0.15
64	CANNERY LOOP, STERLING UNDEFINED GAS	Sterling	22.00	0.00e+00	1514.33	40.00	15.19	23.18	Inactive	0.00e+00	6.51e+08	1.32e+07	0.00e+00	0.00e+00	0.72
65	KENAI LOOP, UNDEFINED GAS	Unknown	nan	nan	nan	nan	nan	nan	Producing	467.58	7.79e+08	7.35e+06	0.29	6.00e−07	0.93
66	KENAI, STERLING UPPER UNDEF GAS	Sterling	nan	nan	nan	nan	nan	nan	Inactive	0.00e+00	4.98e+07	6.55e+06	1.73e−04	0.00e+00	0.06
67	KITCHEN LIGHTS, BELUGA UNDEFINED GAS	Beluga	nan	nan	nan	nan	nan	nan	nan	0.00e+00	8.70e+08	1.19e+07	0.37	0.00e+00	1.03
68	KITCHEN LIGHTS, STERLING UNDEFINED GAS	Sterling	nan	nan	nan	nan	nan	nan	Producing	0.00e+00	2.19e+08	1.04e+07	0.46	0.00e+00	0.26
69	KITCHEN LIGHTS, TYONEK UNDEFINED GAS	Tyonek	nan	nan	nan	nan	nan	nan	nan	0.00e+00	0.00e+00	0.00e+00	nan	nan	0.00e+00
70	KUSTATAN, KUSTATAN FIELD 1 GAS	Unknown	nan	nan	nan	nan	nan	nan	nan	0.00e+00	9.71e+06	1.37e+06	0.00e+00	0.00e+00	0.01
71	LONE CREEK, UNDEFINED GAS	Unknown	nan	nan	nan	nan	nan	nan	nan	0.00e+00	3.16e+08	7.65e+06	0.00e+00	0.00e+00	0.38
72	NICOLAI CREEK, BELUGA UNDEFINED GAS	Beluga	nan	nan	nan	nan	nan	nan	nan	0.16	1.28e+08	2.25e+06	0.20	1.24e−09	0.15
73	NICOLAI CREEK, SOUTH UNDEF UPPER TYONEK GAS	Tyonek	nan	nan	nan	nan	nan	nan	Producing	0.00e+00	5.11e+07	2.22e+06	2.30e−04	0.00e+00	0.06
74	NIKOLAEVSK, TYONEK UNDEFINED GAS	Tyonek	16.00	8.00	2287.50	61.11	27.29	6.71	Producing	0.00e+00	4.98e+07	4.07e+06	0.05	0.00e+00	0.06
75	NINILCHIK, UNDEFINED GAS	Unknown	nan	nan	nan	nan	nan	nan	nan	0.00e+00	1.22e+08	9.06e+06	1.00	0.00e+00	0.14
76	NORTH COOK INLET, NCI STRLG UNDEFINED GAS	Unknown	nan	nan	nan	nan	nan	nan	nan	0.00e+00	1.78e+07	3.36e+06	0.00e+00	0.00e+00	0.02
77	PIONEER, TYONEK UNDEFINED GAS	Tyonek	nan	nan	nan	nan	nan	nan	nan	0.00e+00	8.38e+04	5248.94	0.00e+00	0.00e+00	9.95e−05
78	REDOUBT SHOAL, UNDEFINED G-O GAS	Unknown	nan	nan	nan	nan	nan	nan	nan	0.00e+00	1.28e+07	3.02e+06	0.00e+00	0.00e+00	0.02
79	REDOUBT SHOAL, UNDEFINED TYONEK GAS	Tyonek	nan	nan	nan	nan	nan	nan	Inactive	0.00e+00	2.62e+07	1.64e+06	0.00e+00	0.00e+00	0.03
80	SEAVIEW, UNDEFINED GAS	Unknown	nan	nan	nan	nan	nan	nan	Producing	0.00e+00	5.16e+06	9.55e+05	0.00e+00	0.00e+00	6.13e−03
81	STERLING, LOWER BEL/TYONEK UNDEF GAS	Tyonek	9.00	11.00	2354.60	49.44	26.88	21.96	nan	0.00e+00	2.82e+07	1.65e+06	0.00e+00	0.00e+00	0.03
82	STERLING, UPPER BELUGA UNDEF GAS	Beluga	12.00	1.50	2881.95	65.56	36.96	16.77	Inactive	0.00e+00	2.58e+08	6.25e+06	0.00e+00	0.00e+00	0.31
83	SWANSON RIVER, BELUGA GAS	Beluga	30.00	110.00	1426.18	40.56	14.61	6.71	Inactive	22.89	1.52e+08	3.30e+06	0.40	1.50e−07	0.17
84	SWANSON RIVER, HEMLOCK FROM STERLING UNDF OIL	Hemlock	nan	nan	nan	nan	nan	nan	Inactive	58.51	3.19e+04	3.19e+04	0.00e+00	1.83e−03	3.79e−05
85	THREE MILE CREEK, BELUGA GAS	Beluga	nan	nan	nan	nan	nan	nan	nan	0.00e+00	7.42e+07	3.40e+06	0.00e+00	0.00e+00	0.09
86	W FORELAND, TYONEK UNDEFINED 4.0 GAS	Tyonek	nan	nan	nan	nan	nan	nan	nan	0.00e+00	2.28e+08	5.12e+06	0.00e+00	0.00e+00	0.27
87	W FORELAND, TYONEK UNDEFINED 4.2 GAS	Tyonek	nan	nan	nan	nan	nan	nan	nan	0.00e+00	9.09e+07	4.29e+06	0.00e+00	0.00e+00	0.11
88	W MCARTHUR RIV, WMF HEMLOCK UND OIL	Hemlock	nan	nan	nan	nan	nan	nan	Producing	4.80e+04	2.54e+06	1.94e+05	0.14	0.02	3.02e−03
89	W MCARTHUR RIV, WMF L TYNK G UND OIL	Unknown	nan	nan	nan	nan	nan	nan	nan	1205.92	6.21e+04	1844.22	0.49	0.02	7.38e−05
90	W MCARTHUR RIV, WMF L TYNK G UPPER UND OIL	Unknown	nan	nan	nan	nan	nan	nan	nan	8.44e+04	4.35e+06	1.30e+05	0.49	0.02	5.17e−03
91	WOLF LAKE, BELUGA-TYONEK UNDEF GAS	Tyonek	nan	nan	2058.45	51.67	23.45	8.54	nan	0.00e+00	2.33e+07	2.30e+06	0.00e+00	0.00e+00	0.03

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