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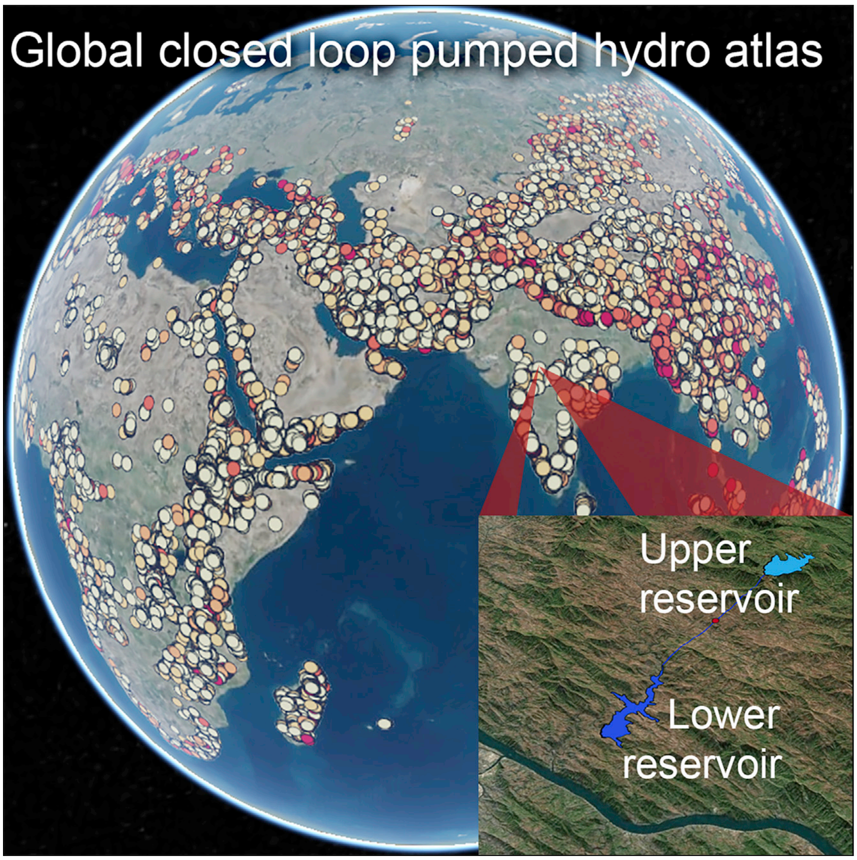
Global Atlas of Closed-Loop Pumped Hydro Energy Storage



Wind turbines and solar photovoltaic (PV) collectors comprise two thirds of new generation capacity but require storage to support large fractions in electricity grids. Pumped hydro energy storage is by far the largest, lowest cost, and most technically mature electrical storage technology. Closed-loop pumped hydro storage located away from rivers ("off-river") overcomes the problem of finding suitable sites. GIS analysis ranging has identified 616,000 individual systems, demonstrating that storage is not a constraint to wind and PV deployment.

Matthew Stocks, Ryan Stocks, Bin Lu, Cheng Cheng, Andrew Blakers

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HIGHLIGHTS

Closed-loop, off-river pumped hydro increases potential for electrical storage

GIS analysis was used to assess the global closed-loop hydro resource

616,000 potential sites identified with combined storage potential of 23,000 TWh

Wide distribution of sites can support large future fractions of wind and solar

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Global Atlas of Closed-Loop Pumped Hydro Energy Storage

Matthew Stocks,[1,2,*] Ryan Stocks,[1] Bin Lu,[1] Cheng Cheng,[1] and Andrew Blakers[1]

SUMMARY

The difficulty of finding suitable sites for dams on rivers, including the associated environmental challenges, has caused many analysts to assume that pumped hydro energy storage has limited further opportunities to support variable renewable generation. Closed-loop, off-river pumped hydro energy storage overcomes many of the barriers. Small (square km) upper reservoirs are typically located in hilly country away from rivers, and water is circulated indefinitely between an upper and lower reservoir. GIS analysis of high resolution global digital elevation models was used to determine economically feasible closed-loop scheme locations outside protected and urban areas. This search identified 616,000 potential storage sites with an enormous combined storage potential of 23,000 TWh. This is two orders of magnitude more than required to support large fractions of renewable electricity, allowing flexible site selection. Importantly, the resource is widely distributed to effectively support large-scale solar and wind deployment for electrical grid decarbonization.

Context & Scale

Wind turbines and solar photovoltaic (PV) collectors dominate new electricity capacity additions. Wind and solar PV are variable generators requiring storage to support large fractions of total generation. Pumped hydro energy storage is the largest, lowest cost, and most technically mature electrical storage technology. However, new river-based hydroelectric systems face substantial social and environmental opposition, and sites are scarce, leading to an assumption that pumped hydro has similar limited potential.

Closed-loop pumped hydro storage located away from rivers (''off-river'') overcomes the problem of finding suitable sites. We have undertaken a thorough global analysis identifying 616,000 systems, available on a free government online platform. This immense pumped hydro resource demonstrates that low cost energy storage is not a constraint to wind and PV deployment for most of the world. Understanding this helps overcome a key barrier to continued deployment of variable renewables.

INTRODUCTION

Solar photovoltaic modules (PV) and wind turbines are now the largest and second largest sources of net new electricity generation capacity, respectively, with 97 GW of solar PV and 59 GW of wind installed in 2019.[1] The economics of these technologies have reached the point where they are now the lowest cost sources of electricity generation in many regions, resulting in expectations of continued growth. These sources of generation are variable in nature—the amounts of energy delivered depends on the amount of wind and solar insolation available.

Energy storage will be necessary to support large fractions of wind and solar PV penetration in electricity networks. Studies at a world wide[2,3] and country-level scale[4–8] have identified that storage will be key to managing a future grid with very high penetration of variable renewables. Storage technologies in these studies include batteries, power to gas (hydrogen or methane), thermal storage, and pumped hydro energy storage.

Pumped hydro energy storage is a form of potential energy storage. A system comprises two reservoirs at different elevations connected by either pipes or tunnels. The difference in elevation is called the ''head.'' When providing electricity to the electricity network, water flows from the upper reservoir to the lower reservoir along the pipes or tunnels through a turbine connected to a generator, much like a conventional hydroelectricity generation scheme. However, when there is an excess of electricity available, water is pumped from the lower reservoir to the upper reservoir. The pump can be a separate unit or, as is often the case, the turbine/generator is reversible and acts as the pump/motor.

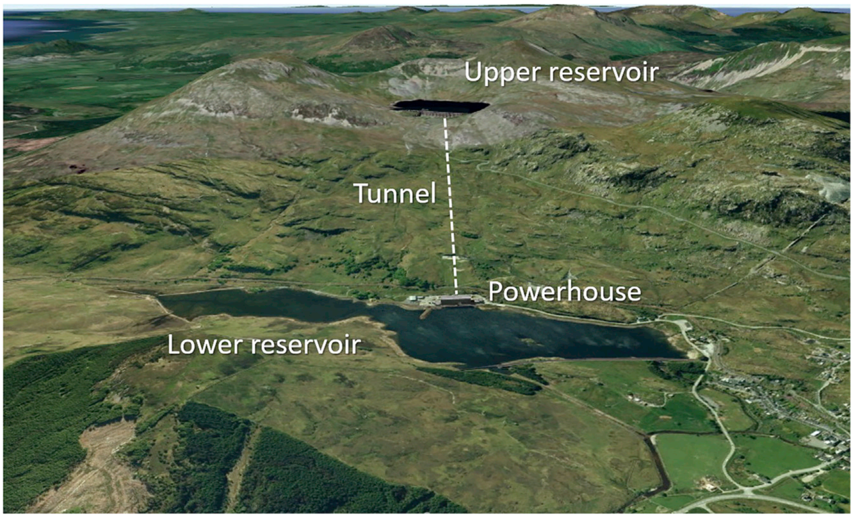

Figure 1. An Example of a Closed-Loop, Off-River Pumped Hydro Storage System: Ffestiniog Power Station in Wales

The scheme comprises high head and small reservoirs. Background image from Google Earth.

Pumped hydro energy storage was originally developed to manage the difference between the daily cycle of electricity demand and the baseload requirements for coal and nuclear generators: Energy was used to pump water when electricity demand was low at night, and water was then released to generate electricity during the day. Consequently, pumped hydro is currently the largest source of electrical energy storage with more than 95% of the world's electricity storage power (GW) capacity and 99% of the storage energy (GWh). Despite this, many studies considering high fractions of renewable energy in future electrical systems ignore pumped hydro storage.[3,5] Others assume no growth in pumped hydro energy storage[2] or limit the growth in pumped hydro to the scale of the conventional hydroelectricity resource. The topography requirements of conventional pumped hydro are often cited as a reason for the need to develop other storage technologies.[9,10]

A closed-loop, "off-river" pumped hydro overcomes these constraints. The upper reservoir for these schemes is located high in hilly areas rather than in a river valley. Closed-loop schemes recycle water between the two reservoirs; that is, the water is cycled between the upper and lower reservoirs during operation with no aim to capture water in the upper reservoir for additional power generation. Water consumption is only required to replace the difference between evaporation and seepage, and rainfall. The reservoirs are also typically small, of the order of tens to hundreds of hectares. Locating upper reservoirs away from rivers and the small area of the reservoirs greatly reduces the environmental impact. It also minimizes the need to manage large flood events, which substantially reduces construction cost. Since most of the world's land surface is not near a river, there are vastly more potential areas for off-river compared with on-river pumped hydro systems.

The Ffestiniog Power Station, as shown in Figure 1, is an exemplar for closed-loop, off-river systems. This site has good head (300 m), low separation keeping tunnels short (1.3 km), small reservoir areas (10 and 30 Ha) and limited upper reservoir catchment (160 Ha). It is designed purely for energy storage with no rivers dammed for power generation (as usually associated with conventional hydro schemes). Raccoon Mountain pumped hydro schemes in the United States is another example

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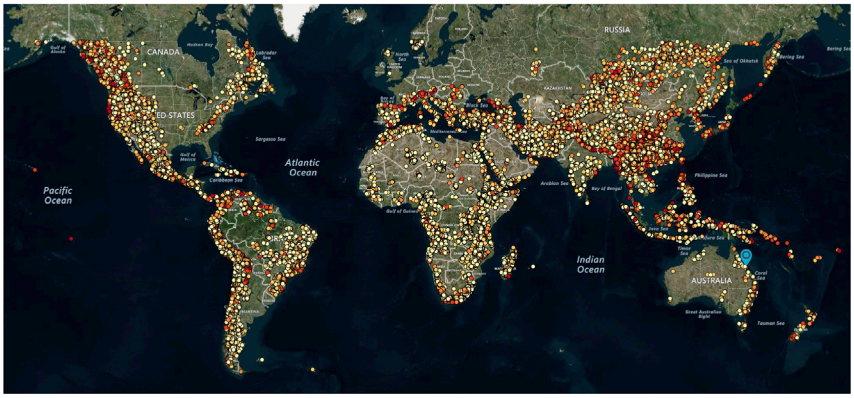

Figure 2. Distribution of Large 150 GWh 18 h Storage Closed-Loop Pumped Hydro Storage Sites Identified in this Study

Lowest costs sites are shown in red with yellow representing sites with twice the capital cost. Similar regional distributions occur with smaller sized schemes but with larger numbers of sites. Image credit: Data61 hosting and Bing Map background.

of a closed-loop, off-river schemes with no intent to capture additional water for energy.

Resource assessments are an important component of understanding the potential role of a technology in the energy mix. This work is the first global assessment of closed-loop, off-river pumped hydro energy storage opportunities. Suitable locations for closed-loop, off-river pumped hydro energy storage depend critically on the local topography. We have developed algorithms for efficiently identifying potential reservoir locations and pairing reservoirs to simulate closed-loop, off-river pumped hydro sites for a range of scheme sizes. A cost model is then applied to determine if the characteristics of the reservoir pair meet a minimum economic standard. All sites that meet the criteria are then ranked into cost classes A through E (with E double the capital cost of A) and three-dimensional (3D) visualization developed.

RESULTS

Our analysis has identified 616,818 low cost closed-loop, off-river pumped hydro energy storage sites with a combined storage potential of 23.1 million GWh. The capacity is the sum of the energy storage from non-overlapping reservoir pairs with the larger storage capacity given priority over smaller capacity pairs to avoid double counting locations with different energy storage. This resource is widely distributed across the world as exemplified by the 150 GWh sites shown in Figure 2. A table with the identified resources for each country is provided in the Supplemental Information.

The 3D visualization of one potential closed-loop, off-river site is presented in Figure 3. This is a 50 GWh, 18 h storage site that could nominally maintain 2.8 Gigawatts (GW) of power output for 18 h. The lower reservoir is visualized in dark blue in the foreground and the upper reservoir in light blue. Neither reservoir has significant catchment area, and both are located away from the major local watercourse visible in the foreground. A combination of high head, low separation of the reservoirs, and low dam wall volumes result in relatively low capital cost.

Zoomable 3D visualization of all 616,000 sites in the global atlas (such as those illustrated in Figure 3) is hosted on the Australian government's renewable energy

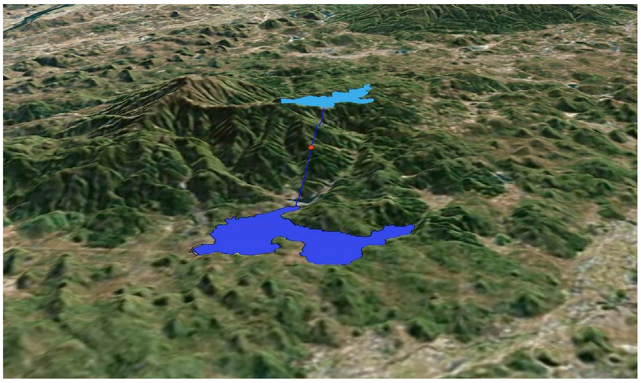

Figure 3. 3D Visualization of a Class A, Off-River Pumped Hydro Site in Southern China.
Image credit: Data61 hosting and Bing Map background.

mapping infrastructure website.[11] Included in the visualization of each site is the reservoir shape, the dam walls, and a notional tunnel route between the reservoirs. Detailed ''pop-up'' information for the site is available by selecting the reservoir or the connecting tunnel.

The pumped hydro resource is well distributed at a regional and sub-regional level to support variable renewable energy deployment. The pumped hydro storage capacity resource per million people for the UN geo sub-regions is shown in Figure 4. The target value of 20 GWh per million people[8] is the storage required to support 100% renewable electricity for a grid dominated by variable renewables over a wide geographical region in a high-energy-consuming developed country (Australia). Every UN sub-region, except for Micronesia, Northern and Western Europe, and Western Africa has more than 1,000 GWh of storage capacity per million people.

The contributions of the 616,000 sites to the total resource is displayed in Figure 5. Schemes were simulated with storage capacities of 2, 5, 15, 50, and 150 GWh and power to operate for either 6 or 18 h at full capacity.

The cumulative capacity of the schemes contributing to the total off-river resource are categorized by site characteristics and approximate capital cost. Estimation of the cost is discussed in detail in the Supplemental Infromation. In summary, the estimated cost of possible systems is arranged in bands from lowest to highest and the five best bands are displayed in published data (A to E, with cost-class A being the lowest and best). Several key trends emerge from these data. Larger systems contribute more to the total capacity than smaller systems resulting in an average capacity across all schemes of 40 GWh. The distribution of sites across the cost classes changes with increased storage capacity with classes A and B containing the largest proportion of 150 GWh sites, while classes D and E dominate the smaller 2, 5, and 15 GWh systems.

DISCUSSION

Global Pumped Hydro Resource

The immense closed-loop pumped hydro resource identified in this study demonstrates that availability of low-cost large-scale storage is not a limitation on the wide deployment of variable renewable energy generation.

The total global storage capacity of 23 million GWh is 300 times larger than the world's average electricity production of 0.07 million GWh per day.[12] Pumped hydro

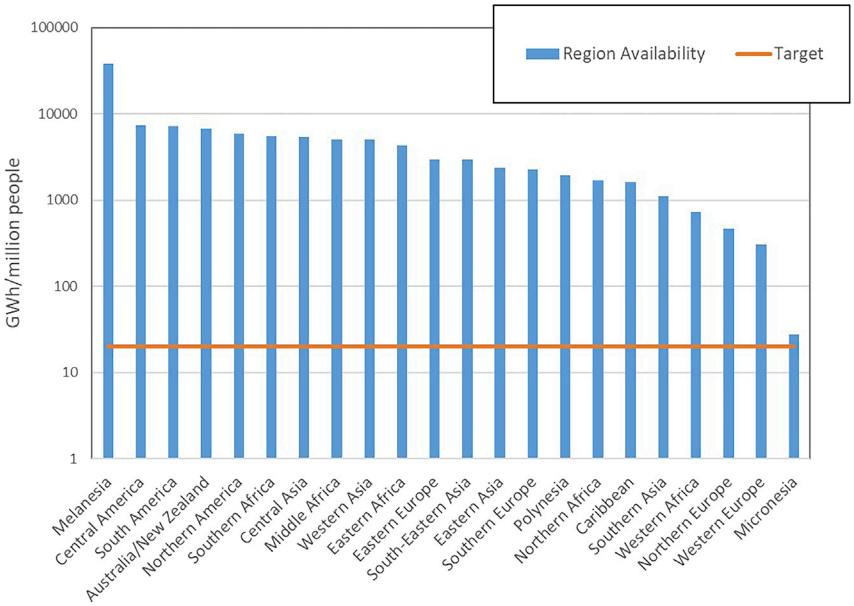

Figure 4. Off-River Pumped Hydro Resource Per Capita for UN Geo Sub-Regions.
The target of 20 GWh per 1 million/people can support a 100% renewable system.

energy storage will primarily be used for medium term storage (hours to weeks) to support variable wind and solar PV electricity generation. It is expected that pumped hydro supporting a system dominated by solar PV will cycle daily (~350 cycles per year), while storage over several days to a week may be needed to support typical wind cycles (50–100 cycles per year). This suggests a total storage requirement of the order of 1% of the annual energy demand, which means that significantly less than 1% of the sites in the atlas need to be developed to support 100% renewable electricity.

More than 70% of the world's population lives in the " sun belt" between 35° N and 35° S.[13] In this region, the monthly solar resource varies by less than a factor of two between summer and winter. Furthermore, in this range of latitudes, the number of cooling days typically exceeds the number of heating days,[14] indicating that electricity loads will be greater in summer when the solar contribution is higher. The need for a significant seasonal storage is therefore expected to be low for the majority of the world's population.

Low to moderate penetration of wind and solar PVs in electricity networks can be largely treated as a small perturbation on the system resulting in less demand needing to be met by other generation sources. The point where difficulties start to arise in an isolated electricity system is usually reported to be in the range of 20% to 50%.[15,16] Flexible demand and generation, and sharing supply and reserves across larger regions with transmission all support balancing supply and demand at these levels.[17] More than 40% has been managed with these approaches in regions within larger grids, including South Australia,[18] which is part of the larger Australian national electricity market, and Denmark,[19] within the larger European market.

The quantum of storage required is substantially reduced for large regions of connected network, allowing sharing of wind and solar resources over larger areas. The national electricity market in Australia provides electricity for most of the

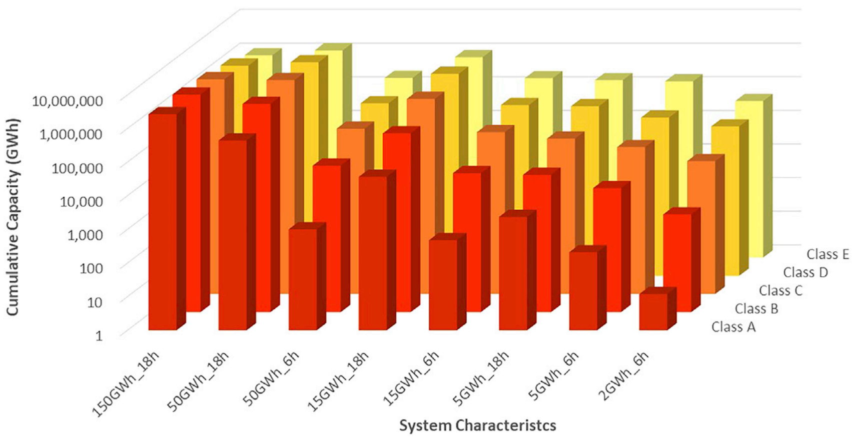

Figure 5. Cumulative Capacity of the Schemes Contributing to the Total Off-River Resource Sorted by Economic Class and Capacity

Australian population. The transmission network extends for more than 3,000 km North-South. Blakers et al.[8] found that if this system, with annual demand of 205 TWh, was dominated by variable wind and PV generation, the required storage is 400–500 GWh, which is about 20 GWh per million people. Australia is a developed country with a high per capita level of electricity consumption. This quantity of storage corresponds to 80% of average daily demand. Extrapolated to a world in which 9 billion people have similar levels of electricity consumption to Australia, the required storage is of the order of 180,000 GWh. Again, this is less than 1% of the identified closed-loop pumped hydro storage resource.

The present work is restricted to greenfield off-river sites. Brownfield sites comprising existing reservoirs and old mining sites have not yet been included. Therefore, the scale of the economically viable pumped hydro resource will be greater than modeled here. There are significant potential cost savings associated with using existing reservoirs, as has been proposed for some projects. While global databases of large reservoirs do exist,[20] examination of the use of these reservoirs show that less than 25% have hydroelectricity production as their primary use. Other uses include irrigation, drinking water, and transport, which all have potential conflicts with energy production. A significant advantage of developing off-river greenfield schemes is that energy storage would be the sole priority.

The maximum head used in this study is limited to 800 m as outlined in the Methodology. There are additional opportunities with higher head. 800 m corresponds to the upper limit for reversible Francis turbines,[21] which is the dominant turbine technology. Higher heads require ternary equipment with separate multistage pumps, usually in combination with impact turbines, such as pelton designs. These schemes require custom engineering beyond the scope of this analysis.

Seawater-based pumped hydro schemes are excluded from this work. In these schemes, the ocean is the lower reservoir, which would reduce the lower reservoir cost, and saltwater is used as the working fluid. There has been one such scheme developed, the experimental 30 MW scheme in Okinawa in Japan, which operated for 17 years from 1999 to 2016.[22] There are proposals for sea water schemes, for example in Chile[23] and Australia,[22] but there are significant environmental and engineering challenges to overcome. Turbine costs are likely to be high because vending companies may apply an engineering uncertainty premium. Additionally, land use conflicts could be significant, because hilly regions adjacent to the sea are relatively uncommon and are often socially or environmentally sensitive.

Distribution of Pumped Hydro Resource

The distribution of pumped hydro sites identified indicates that there is adequate storage available in most sub-regions to support high fractions of variable renewables. Most UN sub-regions had more than 1,000 GWh of storage potential per million people, which is approximately two orders of magnitude more than the 20 GWh target.[8]

The location of pumped hydro resources identified in this work depends on the local topography. An initial requirement is a minimum altitude for the upper reservoir. Areas with maximum altitudes above sea level of less than 100 m, such as many small island states and some coastal countries like Gambia, Qatar, and Netherlands, have no attractive potential pumped hydro resource.

The second requirement is sufficient local height differences to enable potential energy storage. While altitude often indicates resource potential, large areas of central Australia, Africa, North America, and Europe have significant altitude (>400 m), but few sites were identified because the landmass is flat with low slope. Paraguay and Uruguay are examples of countries with some areas of moderate elevation but insufficient slope. Generally, the best regions correspond well with major mountain ranges, such as the Andes in South America, Rockies in North America, and Himalayas in Asia, all well endowed with sites. Less prominent ranges of moderate heights, such as the Appalachians in the western United States and the Great Dividing Range in Australia, also offer enough height difference for a high density of sites.

Some sub-regions, such as Northern and Eastern Europe, had lower per capita resources. However, these regions are part of the larger European electricity market, which includes Western and Southern Europe, which have much better topography. The European transmission network allows sharing of electricity resources across Europe. The per capita resource for the four UN sub-regions of Europe is more than 2,700 GWh per million people. Micronesia, which represents less than 0.01% of the world's population, is the only UN region with inadequate pumped hydro resource and is instead likely to be dependent on batteries or hydrogen for electricity storage.

Large-area electricity networks with high levels of wind and PV need less storage than smaller networks, because adverse local weather is smoothed out. Sharing of resources within and between regions reduces combined generation and demand variability, which in turn reduces reserve provisions. Supergrid proposals connecting Asia or connecting northern Europe with southern Europe and northern Africa are likely to support efficient storage development.

It should be noted that this study was undertaken remotely without any on-site verification. Only areas of high urban density[24] and designated protected areas[25] were excluded. Local environmental, cultural, hydrological, economic, or geotechnical aspects may prevent use of some sites or affect their engineering suitability. However, many locations have several similar alternative sites in the local proximity.

Capital Cost of Storage

The scale of the identified resource is two orders of magnitude greater than required to support widespread deployment of variable renewables. This allows for very selective development of sites. In most regions, this enables a focus on the lowest capital cost (class A and B sites) for practical implementation. Detailed information on the calculation of capital costs is presented in the methodology section. In this section, general trends and their implication for distribution of sites are discussed.

The capital cost of an off-river pumped hydro system can be approximately divided into capital costs associated with generating power (\$/GW) and those associated with the capital cost of energy storage (\$/GWh). Capital costs associated with power comprise the water conveyance, machine hall, pump/turbine, generator, and substation. The capital costs associated with storing energy comprise the two reservoirs. The capital costs for power (GW) and energy storage (GWh) can be sized independently resulting in an associated storage time, which is the ratio of these two components in the scheme. In this work, we considered 6 h of storage, which aligns well with storage for the peak generation of solar PV modules, or 18 h, which some co-authors found optimal for a large fully integrated network.[8]

Compared with a river-based hydro scheme, a closed-loop, off-river pumped hydro systems has an important advantage: The upper reservoir can be located near a hilltop rather than in a river valley, which substantially increases the height difference ("head") between the reservoirs and hence the available potential energy. Generally, a large head is preferred. For example, for otherwise identical systems, doubling the head halves the water storage requirement for the required energy storage target, and substantially reduces the required size and cost of the turbines and tunnels for a given power output. The principal cost of building a reservoir is the cost of moving rock to form the dam walls. The dam walls are assumed to be composed of local rock constructed in the form of a wall with a slope (width to height) of 3:1 on both the upstream and downstream sides. Doubling the height of the wall increases the volume and cost of the wall per unit length by approximately a factor of 4. Doubling the wall height also increases the required length of the wall, by an amount determined by the local geography. On the other hand, doubling the height of the wall increases the volume of impounded water, typically faster than the square but slower than the cube of the wall height, depending on the local geography. The water-to-rock ratio is the ratio of the volume of impounded water to the volume of required rock and is the principal figure of merit for an off-river reservoir. The economics of sites generally improves with larger wall height and hence storage volume as seen in Figure 5. Small storages (2–15 GWh) generally fall into higher cost classes (D and E), while large storages (50 and 150 GWh) have more even distribution between cost classes.

In our study, head can vary by a factor of eight (100 m to 800 m), while the water-to-rock ratio can vary by a factor of more than one hundred, resulting in potential differences in storage costs for the systems analyzed of three orders of magnitude.

A system with relatively short storage times (e.g., 6 h at full power), and therefore higher power, are more expensive than the same system with lower power (e.g., 18 h at full power), because the cost of building the reservoirs is the same, but the power components are larger.

Batteries are currently able to compete with pumped hydro storage for high power applications with short term storage (minutes to an hour or so). However, for storage of hours to days, the levelized cost of storage (LCOS) for closed-loop, off-river pumped hydro is the lowest of the current electrical energy storage technologies and is expected to be lowest for at least several decades as discussed in the later cost section.

Water and Environmental Impact

A challenge for development of pumped hydro energy storage facilities has been the association with traditional river-based hydroelectric power schemes with large energy storages on rivers and the associated construction and environmental challenges.[26] Other studies[27] raise conflicts with alternative water use, such as agriculture and town water supply as limits to the opportunities for pumped hydro, and focus on upgrading existing reservoirs for conversion to pumped hydro systems. The National Hydropower Association[28] recognized the growing opportunity for pumped hydro, but considered that environmental aspects are limiting the opportunity for new river-based pumped hydro schemes in the United States.

In contrast, the water impact of closed-loop, off-river pumped hydro is expected to be small. Unlike conventional hydro, which generates energy by passing captured water through the turbine only once, closed-loop cycling in pumped hydro schemes result in stored water being used of the order of 100 times per year. For a typical head around 400 m, 1 GWh of energy storage requires approximately 1 Gigalitre (GL) of water storage, as shown in Equation 1.

Developing around 1% of the identified resource, as suggested in the earlier discussion, would require a world-wide storage of around 200,000 GL. If developed over the next twenty years as we transition to low carbon electricity networks, the annual withdrawal would be only 10,000 GL per annum. This is a tiny fraction of the world's annual water withdrawal of around 3,000,000 GL.[29] Ongoing operation would need to replace the difference between evaporation and rainfall, and water availability would be an important consideration when developing any particular site.

Shifting to renewable electricity is likely to reduce total water withdrawals. According to the UN Food and Agriculture Organization data,[29] 90% of total industrial water withdrawal in the United States is cooling water for thermal based power generation, which would be eliminated with future fossil fuel phase out. Analysis of Australia's electricity system indicated that a 100% renewable electricity system supported by pumped hydro would use much less water than the current thermal dominated system.[30] Most of the water use would be to replace evaporation from reservoirs.

Environmental impact of closed-loop pumped hydro is expected to be modest. The GIS analysis for the atlas already excludes reservoirs that would impinge on sites in the World Protected Area Database.[25] The footprint required averages 6 Ha of combined reservoir area per GWh of storage. Using the aforementioned figure of 20 GWh per million people[8] for the required storage to support 100% renewable electricity, this equates to only 1.2 square meters per person—smaller than an average bathtub.

Another perspective to understand the scale of the area requirement for pumped hydro energy storage is to compare to the land needed for the associated generation. A solar farm with a daily output of 1 GWh requires an area of land that is about 300 Ha (assuming 18% efficient modules, a capacity factor of 16%, and a module packing density of 50%). Thus, the area required for storing that energy (6 hectares per GWh) is 50 times smaller than the associated solar farm. In summary, finding enough land for off-river pumped hydro reservoirs is unlikely to be a major problem in most regions.

Prospective off-river pumped hydro storage sites vary from tens to hundreds of hectares, much smaller than typical on-river hydro energy reservoirs. Tunnels and underground power stations, as assumed in the costing methodology, can be used in preference to penstocks to minimize other surface impacts. The 2 GW, 350 GWh Snowy 2.0 scheme in Australia, presently under construction within the Kosciusko National Park World Heritage area to support Australia's rapid deployment of wind and solar, includes 27 km of tunnels and underground power station to minimize environment damage.

EXPERIMENTAL PROCEDURES

Resource Availability

Lead Contact

Requests for further information should be directed to the Lead Contact, Matthew Stocks (matthew.stocks@anu.edu.au)

Materials Availability

No materials were generated in this study.

Data and Code Availability

The global atlas output data are hosted on the Australian Renewable Energy Mapping Infrastructure[11]. The code used for identifying sites is open source and available on Github[31].

Site Identification

Potential closed-loop pumped hydro locations were identified by simulating reservoirs in the landscape and evaluating if there was another suitable reservoir nearby to form a pair. The approach used to identify prospective reservoir location builds on the "dry gully" approach described by a subset of co-authors in Lu[32]. This work expands the single reservoir search algorithms to pair upper and lower reservoirs for pumped hydro schemes and, importantly, includes costs for ranking sites. Significant speed improvements have been achieved through optimization of the algorithms and moving to a machine compiled language. This enables a global search to be undertaken in practical time frames. The code is freely available and open source[31].

Reservoir analysis used the 1 arcsecond digital elevation data from the NASA Space Shuttle Radar Topography Mission[33]. This datum has 30 m spatial resolution at the equator and has 1 m height resolution. The 14,281 land-based 1 degree by 1-degree digital elevation tiles were filled to remove local depressions. These tiles covered the region between 60° N and 56° S and encompassed more than 99.7% of the world's population.

Increased processing speed has eliminated the need for the initial filtering of prospective regions that was described in in Lu[32]. Instead, every potential reservoir across all the land-based tiles were identified according to the search criteria. Initially, a virtual stream network with a minimum 10 Ha catchment was developed and potential dam locations to be simulated identified at 10 m height intervals along the streams. A maximum reservoir depth was determined as the lower limit of 100 m or an overlap of defined exclusions zones. In this analysis, this comprised the World Database of Protected Areas[25] and regions of high urban density[24]. Characteristics of the reservoirs were then determined for water depths varying in 10 m increments to this maximum depth.

Boundaries that were common to the area of the reservoir and the flow catchment were assumed to be the center of the reservoir dam wall. The volume of an earth wall rock filled core dam with a batter of 3:1, freeboard of 1.5 m and crest width of 10 m were determined from the digital elevation model. The material for the dam wall is assumed to be excavated from within the reservoir area and partly contributes to the final water storage volume. Reservoirs with at least one GL of water storage and a stored water to dam volume ratio greater three are retained for further analysis.

Reservoirs were then analyzed as potential upper reservoirs. We explored a range of energy storage sizes of 2, 5, 15, 50, and 150 GWh. Every potential reservoir with a height difference (head) of 100 to 800 m below the target reservoir and with a height difference to separation ratio more than 0.03 (3% slope) were considered as a potential lower reservoir. The head range was based on the typical operating range for reversible Francis turbines[21]. The approximate water depth for the upper and lower reservoirs required was then determined for the target energy storage, for example, 5 GWh, by interpolating the reservoir data. Every pair of reservoirs was then ranked using the interpolated data according to the cost calculation described in the later cost section.

This rough ranking was then used for the final detailed analysis. The highest ranked pair was reanalyzed, adjusting the water depth of both reservoirs until the target energy storage was achieved. The cost of the pumped hydro scheme for that reservoir pair was then determined. Any pair in the rough ranking that contained or overlapped either of these reservoirs was then removed from the list, and the process was repeated for the next highest ranked reservoir pair. This ensured no reservoir was used more than once in the resource assessment for a given storage capacity.

Capital Cost of Storage

The economic feasibility of sites was evaluated to determine inclusion in the database using the approach described below. Further details of the parameterization of the costs are available in the Supplemental Information.

There are two largely independent components to the cost of a pumped hydro system: The reservoirs used for storing water and the power conversion system, which includes the powerhouse (pump/turbine/generator) water conveyance and switchyards. The cost of connecting from the local switchyard to the transmission network is not included as the distance to the nearest appropriate transmission will depend on the local network and will change over time. Schemes closer to existing transmission will be more attractive unless new transmission is being built to support new renewable energy generation, for example. As part of an earlier project, a cost model was developed with hydro engineering consultants using detailed spatial analysis of a range of sites. Cost fitting parameters were then determined for the cost analysis in this work as outlined below. Details of the parameterization are provided in the Supplemental Information. Costs are reported in US$. The available energy, E, stored in the upper reservoir is given by

$$E(MWh) = \frac{f\eta\rho VgH}{3.6x10^{9}} \quad \text{(Equation 1)}$$

where f is the fraction of the reservoir which is usable (85%); η is the turbine conversion efficiency (90%); ρ is the density of water (1,000 kgm^{-3}); V is the upper reservoir volume in m^3; g is the acceleration due to gravity (9.8 ms^{-2}); and H is the hydraulic head in m.

The cost of the energy storage component of the system is primary due to the cost of forming the dam wall, which in turn is proportional to the volume of the dam wall, R.

$$Energystoragecost\left(\frac{\$}{MWh}\right) \cong 4.8x10^5 * \frac{CR}{VH} \qquad \text{(Equation 2)}$$

Here C = \$168 is the average total cost of the reservoir construction in \$/m^3 of earth moved. The lowest energy storage cost is achieved in reservoir pairs with large head and large water-to-rock (V/R) ratios for the target storage capacity.

The relationships for the power component costs comprises two components—tunnel and powerhouse—which have a complex relationship with the characteristics of the site. These fitted relationships were determined by varying the detailed cost model inputs.

A tunnel is assumed for the water conveyance between the reservoirs, because a tunnel is generally more economical for larger schemes and less dependent on route choice. The tunnel comprises of a vertical shaft, whose cost is proportional to the power of the scheme, P, in MW and a horizontal component, which also depends on the separation between the closest points of the reservoirs, S (m) and the head, H (m).

$$Tunnelcost(\$) \cong (66,000P + 17,000,000) + S(1280P + 210,000)H^{-0.54} \qquad \text{(Equation 3)}$$

The cost of the vertical and horizontal component scales with power as the tunnel size is proportional to power and slightly less than the inverse square root of head as the cross-sectional area of the tunnel changes proportionally.

The powerhouse cost comprises the civil, mechanical, and electrical costs. The powerhouse is assumed to be excavated. Civil costs include the excavation of the machine and transformer halls, and tunnels for vehicle access and electrical access. Mechanical includes the pump turbines and motor generators, including commissioning. There are assumed to be two turbines up to 800 MW power, but then additional turbines are added for higher power. These components fit the relationship below across the range of heads and power of interest.

$$Powerhouse\ cost\ (\$) = \$63,500,000 * H^{-0.5}P^{0.75} \qquad \text{(Equation 4)}$$

This results in a general trend of lower costs for increased head, while powerhouse costs increase less than linearly with power due to lower turbine and construction costs per MW for larger schemes. The cost model described in this study benchmarked within 5% of an independent study of pumped hydro capital costs by Entura[34] with the Aud\$680M Entura reference site costing Aud\$710M in the model reported here.

Sites are then classified using this ranking as A-class through E class. Sites with ranking below E class are discarded. An A-class site corresponds to US\$530,000 per MW for the power components and US\$47,000 per MWh of storage components. An A-class site with 6 h of storage would then have a total system capital cost per MW of US\$810,000 while an 18-h storage site would cost \$1,366,000. An 800 MW system with 5 GWh of storage would, therefore, need to have a cost below US\$660 million to be rated as class A. B-class through E class are 25% increments in costs above the A-Class site, with E class sites therefore costing approximately double that of A-Class sites.

Levelized cost is a widely used method to compare the costs of energy technologies over their lifetime. The LCOS can be calculated from

$$Levelised\ cost\ of\ storage = \frac{\sum_i^{Life}\frac{Costs_i}{(1+r)^i}}{\sum_i^{Life}\frac{Energy_i}{(1+r)^i}} = \frac{\sum_i^{Life}Capex + \frac{O\&M_i + Loss_i}{(1+r)^i}}{\sum_i^{Life}\frac{Energy_i}{(1+r)^i}} \qquad \text{(Equation 5)}$$

Table 1. Levelized Costs Calculation Assumptions

Factors	Value	Units (Notes)
Real Discount Rate	5%	
Life	60	Years
Fixed O&M	$8,210	/MW/year
Variable O&M	$0.3	/MWh (pumping and gen)
Periodic O&M	$112,000	(year 20 and 40)
Pump/Gen Efficiency	81%	
Energy Cost (E.g. Solar PPA)	$40	/MWh
Energy	300	cycles per annum

Maintenance costs, lifetime, and efficiency from Akhil et al.

Here, Capex is the initial capital cost, O&M is operation and maintenance and Loss is the energy loss due to inefficiencies of the pumping/generation cycle.

The LCOS for an A-class site with 6 h of storage is US$40/MWh based on the assumptions in Table 1. Furthermore, the penalty for requiring a lowest ranking site compared with an excellent site would only result in an increase of the LCOS by around 60% from $40/MWh to $64/MWh if used for daily balancing of solar. An A-class site with 18 h of storage would need to complete the equivalent of 170 cycles per year to have a similar LCOS.

Capital cost is the dominant contributions to levelized cost varying from 60% for class A sites to 75% for class E. Given the long project life and capital component, the LCOS is very sensitive to the discount rate with a 1% increase in discount rate leading to a 10%–12% increase in levelized cost across the classes.

The levelized cost of battery storage is currently significantly higher and expected to remain so for the foreseeable future. Lazard's analysis shows in the range $US108 to US$222 of for 4 h of storage in the wholesale market[35]. Schmidt et al[36] examine historic costs of electrical storage technologies and apply learning rate analysis to project future prices. They forecast a battery capital cost reduction of 45% to 60% by 2040 relative to 2020 resulting in levelized costs of storage higher than pumped hydro. Batteries have some advantages over pumped hydro storage, including relatively fast construction cycles, modularity and very rapid power response. These storage technologies are highly complementary in a system dominated by wind and solar.

SUPPLEMENTAL INFORMATION

Supplemental Information can be found online at https://doi.org/10.1016/j.joule.2020.11.015.

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AUTHOR CONTRIBUTIONS

Conceptualization: M.S., A.B., and B.L.; Methodology: M.S., B.L., and R.S.; Software, Data Curation and Visualization: M.S. and R.S.; Investigation M.S., C.C., and B.L.; Writing – Original Draft: M.S.; Writing – Reviewing and Editing: M.S., C.C., A.B., and B.L.; Funding Acquisition: A.B. and M.S.

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The authors have no competing interests to declare.

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