Energy Storage: The Regulatory Landscape in Alberta

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Energy storage technologies are increasingly being deployed in Alberta. In the recent past, costs were the largest hurdle to widespread energy storage deployment. But this is changing given falling battery prices.

Indeed, AESO and AUC processes are increasingly considering energy storage development and potential, but within the scope of existing legislation and its policy framework. Alberta's traditional model of electricity regulation is based on generators supplying electricity to load customers for consumption, and does not directly contemplate the unique attributes of energy storage. These attributes include the flexibility of customers to switch between supply and load, such as where a customer discharges a battery into the grid during peak hours and charges the battery during off-peak hours.

Energy market participants and policy makers need to consider the use of flexible resources in an evolving electricity industry where distributed and intermittent power sources are increasingly prominent. Energy storage is playing a key role in this ongoing evolution. To that end, this article seeks to provide practitioners and industry stakeholders guidance on the current state of the Alberta regulatory landscape applicable to energy storage, and anticipated changes.

Specifically, this article sets out the regulatory framework applicable to, and policy issues raised by, energy storage, including tariffs and competitive market issues, the concept of "hybrid sites" and self-supply and export issues, and AUC decisions approving the deployment of energy storage. As to how the landscape may change, this article looks at recent policy statements by the AUC and the AESO describing potential changes on the horizon.

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I. INTRODUCTION

> *"Of all the different types of DERs that are being connected to the grid, energy storage resources and, more specifically, battery energy storage resources, appear to have the most potential for disrupting the status quo while, at the same time, facing a number of regulatory and policy barriers to deployment. This is particularly due to the relative novelty of utility-scale battery storage, its flexibility in switching between load and supply, its potential portability, and the multitude of competitive services battery storage is potentially able to supply. As a result, battery energy storage resources appear to have high potential to significantly alter Alberta's existing regulatory framework."*
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> *—Alberta Utilities Commission (**AUC**)*
> *Distribution System Inquiry Final Report*

Energy storage systems are a commercially viable technology with the potential to disrupt Alberta's existing regulatory framework. This paper seeks to provide electricity industry stakeholders with an overview of the application of the existing regulatory framework to energy storage and a discussion of issues that may require changes.

Energy storage, broadly defined, "is any technology or process that is capable of using electricity as an input, storing the energy for a period of time and then discharging electricity as an output",[1] and it has the potential to transform electricity systems around the world over the coming decades.

There are signs that this transformation has already begun—energy storage's integration into electricity systems has rapidly accelerated worldwide over the last ten years, driven mainly by technological advances coupled with the falling price of batteries. With these trends likely to continue, grid-related energy storage's installed capacity is expected to increase by a multiple of fifteen globally by 2030.[2]

Energy storage has many advocates who expect that it will allow for greater adoption of renewable energy, thus reducing greenhouse gas (GHG) emissions.[3] Beyond the ability to contribute to lower

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[1] "AESO Energy Storage Roadmap" (August 2019) at 6, online (pdf): AESO <www.aeso.ca/assets/Uploads/Energy-Storage-Roadmap-Report.pdf> [**Energy Storage Roadmap**].

[2] "Energy Storage Grand Challenge: Energy Storage Market Report" (December 2020) at 16, online (pdf): U.S. Department of Energy <https://www.energy.gov/sites/prod/files/2020/12/f81/Energy%20Storage%20Market%20Report%202020_0.pdf>.

[3] Alberta Utilities Commission, Distribution System Inquiry: Final Report (February 19, 2021) [**DSI Inquiry**] at Exhibit

emissions, energy storage has other advantages—energy storage is relatively low-cost, scalable, distributed, efficient and low maintenance. A wide variety of storage technologies, each with its own unique attributes, enables a range of applications. There are expected to be increasing opportunities for energy storage systems to "value stack" by earning multiple revenue streams through the provision of multiple system services (e.g. spinning reserve and black start services) which will increase the overall utilization of the of the energy storage system project.

Although energy storage technologies are not new, their recent and rapid proliferation raises new legal and regulatory issues that will require public debate and action.

Alberta is no exception to these novel issues, and public bodies such as the Alberta Electric System Operator (**AESO**) and AUC have concluded that storage must be examined and integrated into Alberta's electricity system.[4] For instance, in the context of Alberta's phase out of coal-fired power plants,[5] energy storage will likely be needed to maintain reliable grid function within the province if a material portion of retired coal generation is replaced with variable renewable energy.[6] Also relevant is Alberta's relative lack of intertie and hydroelectric capacity, both of which may make energy storage particularly important in the Alberta context.[7]

Energy storage could thus disrupt Alberta's electricity market by, among other things, enabling the more widespread adoption of renewable energy to replace Alberta's current carbon-intensive

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24116-X0159, "Module One – Energy Storage Canada Submission" para 25 citing "Commissioner Richard Glick Statement regarding Electric Storage Participation in Markets Operated by RTOs and ISOs" (15 February 2018), online: Federal Energy Regulatory Commission <www.ferc.gov/news-events/news/commissioner-richard-glick-statement-regarding-electric-storage-participation>: "As the cost of energy storage continues to decline, these resources are poised to play an even more important role in the generation mix, leading to the development of a more robust grid that can, among other things, help to accommodate the ever-increasing demand for clean, renewable resources."

[4] Blake Shaffer, "The Role of Storage in Alberta's Electricity Market: Summary of a School of Public Policy Roundtable Event" (2019) 12:28 SPP Summary Paper at 2: "[However, they] broadly agreed that consideration of how storage fits into the electricity market in Alberta needs to be incorporated into ongoing market design reforms." See also DSI Inquiry *supra* note 3 at s 4.6; AESO Storage Roadmap**,** *supra* note 1 at 3.

[5] G Cornelius van Kooten, Patrick Withey & Jon Duan, "How big a battery?" (2020) 146 Renewable Energy 196 at 197.

[6] *Ibid* at 197 and 198, Table 4. For instance, van Kooten et al. estimated that if the entire Alberta generation capacity consisted of renewable generation (mainly wind and solar), then 10,918 MW of ES, consisting mostly of BESS, would be needed to maintain grid stability. If, as planned, two-thirds of generation capacity is provided by renewables by 2030 and coal generation is retired, the required ES capacity would be 549 MW.

[7] Shaffer, *supra* note 4 at 6: "Alberta, relatively speaking, is an electric island, with interconnections totalling little more than 1,000 MW, or roughly 10 per cent of peak load. California, by comparison, counts on nearly a third of its supply on the interties, and is capable of exporting during periods of excess solar as well. In the absence of increased interconnections and large hydroelectric reservoirs, storage may play a larger role in Alberta."

generation methods. Because energy storage technologies were neither as advanced nor as prevalent as they are now even in the relatively recent past, Alberta's existing regulatory framework does not contemplate technologies with energy storage's attributes.[8]

This paper begins with a brief history of energy storage in Part II. Part III then reviews energy storage technology that is currently available and includes an overview of the manufacturing, installation and regulatory challenges unique to each type. Part IV addresses the possible application of energy storage in Alberta, and Part V considers its potential profitability. Part VI outlines several energy storage projects already in place or in development in Alberta, highlighting those that are already showing value. Finally, Part VII looks at the existing regulatory framework and addresses both the barriers and opportunities currently in place.

II. HISTORY OF ENERGY STORAGE

Energy storage has a long history, but it was little used in electricity grids until recently. Today, though, the versatility and falling cost of emerging energy storage technologies[9] is turning energy storage into a key component of modern grids. To underscore the importance of energy storage and provide context, this section provides a brief survey of its history.

Energy storage has been used since ancient times, with the first known use of a battery occurring roughly 2,200 years ago. But these early uses tended to be smaller-scale and for more specialized purposes. Historians, for example, have found evidence of batteries in Iraq created from clay pots, vinegar and copper wire. These rudimentary batteries were thought to be capable of producing up to two volts of electricity, presumably to gild silver jewelry with gold.[10]

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[8] DSI Inquiry, *supra* note 3 at para 22.

[9] The dramatic fall in the levelized cost of energy for solar and wind power plays a complimentary role in the rise in energy storage uptake. Over the last decade, wind and solar development costs have fallen by 70% and 90%, respectively. *See* Schumacher et al, "Cheap Renewables Have Arrived" *Energy & Environmental Policy Trends* (November 2020), online: The University of Calgary School of Public Policy <policyschool.ca/wp-content/uploads/2020/11/Energy-Trends-Renewables-Nov.pdf>.

[10] Elena Danila and Dorin Dumitru Lucache, "History of the First Energy Storage Systems" (Paper delivered at the 3rd International Symposium on the History of Electrical Engineering and of Tertiary-Level Engineering Education, 27-29 October 2010) at 1.

Modern variants of batteries date to 1800, the year "Volta's cell" was devised. Volta's cell, the first modern battery, is a forerunner of today's lead-acid battery, which initially had limited uses.[11] For instance, lead-acid batteries were not used in industrial applications until 1859, when they were used to store energy for telegraphy.[12] It took another 20 years for large-scale production of lead-acid batteries to begin, when several technological innovations increased their storage capacity and made their manufacturing easier.[13]

The invention of the lithium-ion battery in 1977 was key to the increasingly widespread use of energy storage in electricity systems.[14] Even so, a lithium-ion battery was not used in a grid setting until October 2012, when the U.S. Department of Energy installed a 5 MW lithium-ion battery to demonstrate the viability of utility-scale battery energy storage.[15]

Despite storage technology's long history, energy storage only saw rapid and widespread adoption in the last decade. In 2013, only 200 MW of energy storage capacity was deployed globally. By 2019, this number had grown to nearly 3000 MW.[16] As discussed further in Section V, this acceleration has been driven by the falling costs of storage technologies (mainly, lithium-ion batteries), as well as increased wind and solar capacity worldwide.

This growth has not escaped Canadian governments. The federal government has had energy storage on its radar since at least 2016 when the National Research Council of Canada embarked on a project to develop a multi-year energy storage implementation roadmap.[17] Provincially, two Crown corporations, Alberta Innovates and Emissions Reduction Alberta, and Natural Resources Canada

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[11] Stanley Whittingham, "History, Evolution, and Future Status of Energy Storage" (2012) 100 Proceedings IEEE 1518 at 1521; Danila and Lucache, *supra* note 10 at 1.
[12] *Ibid* at 1.
[13] *Ibid*.
[14] Whittingham, *supra* note 11 at 1521.
[15] John Vernacchia, "A Brief History of Utility-Scale Energy Storage" (September 19, 2017), online: Renewable Energy World < https://www.renewableenergyworld.com/storage/a-brief-history-of-utility-scale-energy-storage/#gref>.
[16] "Energy Storage" (June 2020), online: International Energy Agency <www.iea.org/reports/energy-storage#tracking-progress> [**IEA Report**].
[17] Adam Tuck et al, "Canadian Energy Storage Roadmap" (last modified 11 March 2019), online: National Research Council Canada <nrc.canada.ca/en/stories/canadian-energy-storage-roadmap>.

have provided funding for the FortisAlberta Waterton project.[18] In total, Emissions Reduction Alberta has provided funding for seven different energy storage projects.[19]

The long history of energy is developing a new chapter, one marked with many potential applications for energy storage across electricity systems. Before turning to these varied applications, however, a brief canvas of some of the different energy storage technologies is in order.

III. TYPES OF ENERGY STORAGE

There are several different energy storage technologies available. While much of the focus in recent years has rightfully been on battery energy storage systems, other viable technologies exist, including pumped hydro storage and compressed air energy storage technologies. Each of these technologies has different strengths and weaknesses and are thus suited for different applications. Additionally, each has its own manufacturing, installation and regulatory challenges.

Energy storage systems can range from small-scale (typically kW to small MW range), including at the residential level, to utility scale (10's – 100's MW).[20] They vary in physical size, portability, electrical capacity and storage volume. For instance, Ontario's pumped hydro installation at the Sir Adam Beck Pump Generating Station features a 300 hectare reservoir for energy storage, while some residential lithium-ion batteries can fit inside a closet.[21]

The AESO and the Government of Alberta have a working definition of energy storage as "any technology or process that is capable of using electricity as an input, storing the energy for a period of

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18 Re FortisAlberta Inc (January 15, 2021), 26101-D01-2021 at para 8, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2021/26101-D01-2021.pdf> [**Waterton Battery Decision**].

19 "Projects", online: *Emissions Reduction Alberta* <https://eralberta.ca/projects/?project-sort=name_az&p-search=storage>.

20 Jahedul Islam Chowdury at al, "Techno-environmental analysis of battery storage for grid level energy services" (October 2020) 131 Renewable & Sustainable Energy Rev 1 at 2. For example, the Hornsdale Energy Reserve in Australia provides 100 MW of energy storage in lithium-ion batteries manufactured by Tesla (Rob Verger, "Tesla actually built the world's biggest battery. Here's how it works" (2 December 2017), online: Popular Science <www.popsci.com/tesla-building-worlds-biggest-battery-how-it-will-work/>). As a comparison, the Genesee coal fired generation plants (Units 1-3) in Alberta provide 1376 MW of electricity generation ("Genesee Generating Station" (last visited 27 April 2021), online: Capital Power <www.capitalpower.com/about-genesee/>.

21 "Market Snapshot: Pumped-storage hydro – the largest form of energy storage in Canada and a growing contributor to grid reliability" (19 October 2016), online: Canada Energy Regulator <https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2016/market-snapshot-pumped-storage-hydro-largest-form-energy-storage-in-canada-growing-contributor-grid-reliability.html>; Frank Jossi, "Best Home Battery Storage Options" (3 November 2020), online: Build with Rise <https://www.buildwithrise.com/stories/2019-guide-to-the-best-home-battery-storage-options>.

time and then discharging electricity as an output."[22] This definition is expansive and technologically agnostic, and emphasizes the ability of a technology or process to (i) both draw and discharge electricity, and (ii) store energy over time. Whether lithium-ion battery, pumped hydro or compressed air technology, all energy storage technologies share these two common attributes.

A. BATTERY ENERGY STORAGE SYSTEMS (BES)

Although pumped hydro storage is the dominant technology in terms of worldwide capacity,[23] the emergence of battery energy storage systems as a commercially viable technology is what attracted the attention of regulators and stakeholders alike. Batteries are not bound by geographical constraints and considerations of minimum project size, but remain more expensive than some other technologies. Different battery technologies[24] include: (a) solid state,[25] (b) lead-acid, and (c) flow batteries:[26]

a) Solid state batteries are a mature technology limited to specialized applications because of high manufacturing costs.[27] Ideally, lower manufacturing costs will allow for their deployment in electric vehicles because of their attractive characteristics of enhanced safety, greater energy density and faster charging.[28]

b) Lead-acid batteries use an acid solution as an electrolyte and have lead electrodes.[29] They are a mature and inexpensive technology that is widely used to store electricity.[30]

c) Flow batteries are a newer technology that uses chemical components dissolved in a liquid medium as electrodes. The fundamental difference from other battery types is that flow

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[22] DSI Inquiry *supra* note 3 at para 231.

[23] "Electricity Storage Technology Review" (30 June 2020) at 2, online (pdf): United States Department of Energy Office of Fossil Energy <www.energy.gov/sites/prod/files/2020/10/f79/Electricity%20Storage%20Technologies%20%20Report.pdf>.

[24] A fourth battery type is a mechanical battery, or flywheel, that stores kinetic energy instead of chemical energy. Flywheels work by using electricity to drive a motor that spins the flywheel, which allows excess electricity to be stored, and later discharged back to the grid by slowing the flywheel. Flywheels are very responsive and can rapidly discharge energy to the grid quickly, but also have a high self-discharge rate, making them unsuitable for long-term storage, but appropriate for frequency regulation and fast-acting spinning reserves. See SC Flowerday, "The Case for Energy Storage in Alberta, Canada" (August 2020) [unpublished], online: PRISM <prism.ucalgary.ca/bitstream/handle/1880/112641/capstone_Flowerday_2020.pdf?sequence=1&isAllowed=y>; "Energy Storage: Unlocking the Value for Alberta's Grid"(2016) at 11, online (pdf): Alberta Storage Alliance <static1.squarespace.com/static/5733b8d1f8baf3a110770c45/t/579a7561e58c62582a1a8f6e/1493235370224/ASA+White+Paper+-+Energy+Storage+-+Unlocking+The+Value+for+Alberta%27s+Grid.pdf> [**Energy Storage Unlocking Value**].

[25] Solid state batteries use solid electrolytes (the medium that transmits electrical current) as well as solid electrodes (the receptors of the electrical current within the battery).

[26] Energy Storage Unlocking Value *supra* note 24 at 11.

[27] Joo Gon Kim et al, "A review of lithium and non-lithium based solid state batteries" (15 May 2015) 282 J Power Sources 299 at 299.

[28] Mark S Reisch,"Solid-state batteries inch their way towards commercialization" *Chemical & Engineering News* (20 November 2017), online: American Chemical Society <cen.acs.org/articles/95/i46/Solid-state-batteries-inch-way.html>.

[29] Ivan Cowie, "All About Batteries, Part 3: Lead-Acid Batteries" *Power Management Designline* (January 13, 2014), online: EE Times <www.eetimes.com/all-about-batteries-part-3-lead-acid-batteries/>.

[30] Lead acid batteries are used for "for backup applications such as in cell phone towers, high availability settings like hospitals, and stand-alone power systems" (Energy Storage Unlocking Value *supra* note 24 at 11).

batteries can be instantly recharged by the replacement of the fluid, while other batteries must charge in-state.[31]

Lead-acid batteries, specifically lithium-ion and sodium sulphur batteries, dominate the current battery energy storage system market.[32] Of these two, lithium-ion batteries are preferred as high operating temperatures and poor self-discharge properties constrain the utility of sodium sulphur batteries.[33] In contrast, lithium-ion batteries have high energy densities and a low self-discharge rate (<5%/month), require very little maintenance and have a wide range of operating temperatures. The major drawback of lithium-ion batteries is the ethical, economic and environmental issues intertwined with lithium mining.[34]

B. COMPRESSED AIR ENERGY STORAGE SYSTEMS (CAES)

CAES are ideally placed in underground, typically salt, caverns.[35] When energy costs are low, the cavern is pressurized with air and, when needed, this air is heated and expanded to power turbines, generating electricity.[36] CAES has lower efficiency (~70%) than some other storage technologies, but is relatively inexpensive to install and can act as extremely long-term storage with a long operational lifetime.[37]

There is great potential for CAES in Alberta as the geology is favourable, with many salt caverns in the province, and the equipment of the type used in CAES is already deployed in the oil and gas industry.[38] Alberta also possesses many saline aquifers that can provide the water needed to "solution

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[31] Ibid.

[32] Other compositions, such as vanadium redox, show technical promise: Robert Rapier, "Why Vanadium Flow Batteries May Be The Future Of Utility-Scale Energy Storage" *Forbes* (24 October 2020), online: Forbes Magazine <https://www.forbes.com/sites/rrapier/2020/10/24/why-vanadium-flow-batteries-may-be-the-future-of-utility-scale-energy-storage/?sh=73a1f8962305>.

[33] Chowdury et al, *supra* note 20 at 2.

[34] Flowerday, *supra* note 24 at 15 and 16; Matthew A Pellow et al, "Research Gaps in environmental life cycle assessments of lithium-ion batteries for grid-scale stationary energy storage systems: End-of-life options and other issues" (April 2020) 23 Sustainable Materials & Technologies 1 at 1.

[35] Salt caverns provide several characteristics that make them ideal for gas storage, including compressed air and natural gas. They have low base gas requirements (threshold level of gas required to create a gradient) and the ability to support higher rates of injection and withdrawal than other underground formations. They can also be created *de novo* from bedded salt formations by a leaching process, allowing convenient siting in some instances. "The Basics of Underground Natural Gas Storage", *U.S. Energy Information Administration* (November 16, 2005), online.

[36] See Energy Storage Unlocking Value, *supra* note 24 at 12: "Pressure in the caverns can be as high as 3000 psi."

[37] Xing Luo et al, "Modelling study, efficiency analysis and optimisation of large-scale Adiabatic Compressed Air Energy Storage systems with low temperature thermal storage" (15 January 2016) 162 Applied Energy 589 at 589 and 560, Figure 1.

[38] Energy Storage Unlocking Value, *supra* note 24 at 12.

mine" the salt caverns, thereby enlarging them to act as storage reservoirs.[39] In Alberta, some have speculated that wind turbines paired with CAES systems could provide generation services at a similar cost to other GHG-free generating sources like nuclear and hydro.[40]

C. PUMPED HYDRO STORAGE SYSTEMS (PHS)

PHS function by pumping water[41] to a higher reservoir when energy costs are low, and releasing the stored water through turbines to generate electricity as needed.[42] Some suggest that the height difference for PHS systems must be greater than 300 meters between reservoirs for the system to be economically viable.[43]

PHS systems are the main competition to CAES for long-term energy storage today. PHS and CAES have similar efficiency ratings and both are inexpensive to install on a per-energy-unit-generated basis, especially when paired with an existing facility.[44] PHS (and CAES) systems currently have a lower capital cost on a per kWh basis than BES, making them a more attractive option for long duration storage applications, like energy arbitrage.[45] Even so, unlike BES, PHS systems are a mature technology and PHS is not expected to see significant cost reductions in the future. PHS's reliance on particular geographic features also makes it far less flexible than BES.[46]

Although the potential for PHS in Alberta is relatively lower, British Columbia has high hydroelectric potential and the capacity to install PHS. If provincial intertie capacity was expanded, Alberta could benefit from this potential resource.[47] PHS is the most popular form of energy storage

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39 Robert Alexander Stewart, "Cost of Load Following ultra low and zero emissions electricity products using Compressed Air Energy Storage (CAES) in Western Canada" (2020) at 6, online (pdf): RMP Energy Storage <dd636359-f4b5-47b9-9e5f-39b8b9a3fa0a.filesusr.com/ugd/2a9f23_4806080797f447a29ca13f52c833987f.pdf>

40 Ibid at 12.

41 There are also non-hydro pumped storage technologies that operate on a similar principle. For instance, a UK company hoists weights in a vertical shaft using winches to store electrical energy as potential energy. When electricity is needed, the weights are lowered and the winches act as generators (Brett Smith, "What is Gravitricity's Gravity-Based Energy Storage System?" *AZO Cleantech* (10 June 2020), online: AZO Cleantech <https://www.azocleantech.com/article.aspx?ArticleID=1097>).

42 Energy Storage Unlocking Value, *supra* note 24 at 12.

43 Flowerday, *supra* note 24 at 14.

44 Whittingham, *supra* note 11 at 1519.

45 Ganesh Doluweera, Hamid Rahmanifad & Mohammad Ahmadi, "Electricity Storage Systems: Applications and Business Case" (June 2019) at 25, online: Canadian Energy Research Institute <ceri.ca/assets/files/Study_180_Full_Report.pdf>.

46 Ibid.

47 Jonathan van Groll, "Value of Pumped Storage Systems in British Columbia" (2018) [unpublished] at 23-25, online: University of British Columbia <open.library.ubc.ca/cIRcle/collections/ubctheses/24/items/1.0368788>.

globally, accounting for 96 percent of the installed capacity of storage worldwide (300 individual projects totalling 196 GW in operation), with most of the active PHS facilities concentrated in the mountainous regions of Europe and the Eastern United States.[48]

IV. APPLICATIONS OF ENERGY STORAGE

Energy storage has many applications. Energy storage can, among other things, reduce demand peaks, participate in pool price arbitrage, provide reliability services to the grid and mitigate the intermittency of wind and solar power.

These applications are not mutually exclusive. Regulatory framework permitting, an energy storage system can have many simultaneous uses. For example, there are no technological barriers to an industrial customer installing energy storage to supply on-site electricity needs during the monthly coincident peak[49] as a way to manage transmission charges, while using that same energy storage system in all other hours to earn revenue in both the energy and ancillary services markets through energy arbitrage and the provision of operating reserves. This is known as "value stacking".[50]

In this section, we review the benefits of energy storage for energy services and system services. Energy storage may be used for pool price arbitrage, where electricity is stored when prices are low and sold into the grid when prices rise. Energy storage also aids in firming the intermittency of variable renewable resources, like wind and solar, while also addressing Alberta's "wind discount", which leads to depressed prices for wind generation in Alberta. Beyond these energy services applications, energy storage can also support "ancillary services" — the services required to ensure that Alberta's grid is operated in a manner that provides a satisfactory level of service. We identify several areas below where energy storage may show promise.

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[48] Maria C Argyrou, "Energy Storage for Electricity Generation and related processes: Technologies appraisal and grid scale applications" (October 2018) 94 Renewable and Sustainable Energy Rev 804; van Groll *ibid* at 43.

[49] In Alberta, a large portion of transmission costs are recovered through the "12 coincident peak methodology". Under this methodology, the AESO sums the metered demands for all market participants in every 15-minute interval during a month. The monthly coincident system peak is the greatest sum in any 15-minute interval in the month: AESO Information Document, Coincident Metered Demand, ID No. 2005-011T.

[50] DSI Inquiry, *supra* note 3 at para 245.

A. ENERGY SERVICES

Energy services involve, broadly, the supply of energy to the grid for use by load in exchange for the prevailing pool price. Storage can create value in the context of energy services in two main ways: (1) by drawing energy from the grid during low pool price hours for storage purposes, and then releasing that energy back to the grid during higher pool price hours, and (2) storing energy from renewable resources during periods of curtailment and releasing the energy when curtailment ends.

1. POOL PRICE ARBITRAGE

In basic terms, pool price arbitrage is buying electricity at one time, storing that energy, and later selling that same energy for a higher price. As discussed below, variable renewable energy sources, like wind and solar, may benefit from pool price arbitrage when generation exceeds demand (as on a particularly windy night).[51] Rather than wasting the excess generation, it is stored and sold into the grid when prices (and demand) rise. Pool price arbitrage, however, need not be paired with variable renewables to be economical. It may be profitable whenever there is an inexpensive source of electricity, which can be stored and later sold into the grid when electricity prices increase.[52]

When categorizing the economics of pool price arbitrage, there is a strategy divide between long-term, but slow-acting resources (like pumped hydro) and short-term, fast-acting resources (like batteries).[53] The divide is that these resources respond to different scales of time-based variability in the energy markets, and thus are valued differently. Short-term resources arbitrage on hour-to-hour variability, which can require advanced systems to determine short periods of energy scarcity. This

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[51] Doluweera, Rahmanifard & Ahmadi, *supra* note 45 at 2.
[52] Ibid.
[53] Shaffer, *supra* note 4 at 9: "Short-duration storage provides value to deal with hour-to-hour (and in fact minute-to minute) variability. Remuneration can come from energy markets, but also ancillary reserve markets, which explicitly value the fast-acting capability of quick response resources. However, ancillary service markets are notoriously thin, in that the introduction of new supply quickly depresses prices (see, for example, the effect of the Tesla 100 MW battery in South Australia). Thus while storage provides excellent value in managing short-term variability, this opportunity's market size is small. Long-duration storage deals with multi-day seasonal variability. The cost to cover such timeframes with battery technology is seen as too high, given the large installed capacity required and relatively low cycling factor. Longer duration storage tends toward reservoir or pumped-hydro storage."

advanced sensing capability can make deployment of short-term arbitrage capability more risky and difficult, lowering its potential value.

Long-term storage installations can conduct arbitrage on a daily or yearly basis, which can be useful since daily temperature-related trends and longer seasonal trends are easier to predict and match. This predictability and tolerance in response time increases the value of long-term energy storage for arbitrage purposes. In Alberta, for instance, demand peaks in both summer and winter, and an all-time peak load was recorded in January 2020.[54]

Some studies suggest that Alberta energy prices may be insufficiently volatile to support energy storage-based price arbitrage. For instance, one study found Alberta's price floor of $0 per MWh and cap of $1,000 per MWh made energy arbitrage uneconomical, since it shrunk the price difference between stored energy and generation-constrained energy.[55] Similarly, the AESO, in a 2018 study, found the difference between Alberta's daily high and daily low electricity prices was too small to generate significant arbitrage revenue for both large- and small-volume storage. Storage with a capacity of 1 MW generated negligible revenues, even as duration increased from 2 to 12 hours.[56] High-energy, long-duration storage also realized little or no value from energy arbitrage. Increases in capacity (from 75 MW to 500 MW) and duration (from 2 to 12 hours) generated increased arbitrage revenue, but this was offset through increases in operating cost.[57] Opportunities for arbitrage seem greater in markets like Texas, which has a price cap of $9,000 per MWh (a mark it reached during the state's recent, and extraordinary, electricity crisis).[58] Thus, the lower price caps and the relative stability of electricity prices in Alberta may be a continued barrier to generating meaningful arbitrage revenue opportunities.

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[54] Flowerday, *supra* note 24 at 12 citing "AESO 2019 Annual Market Statistics" (March 2020), online (pdf): AESO <https://www.aeso.ca/download/listedfiles/2019-Annual-Market-Statistics.pdf

[55] Shaffer, *supra* note 4 at 8.

[56] "Dispatchable Renewables and Energy Storage" (31 May 2018) at 33 – 34, online: AESO <www.aeso.ca/assets/Uploads/AESO-Dispatchable-Renewables-Storage-Report-May2018.pdf>.

[57] Ibid at 35 – 36.

[58] Brian Eckhouse, Naureen S Malik & Mark Chediak, "Surging Texas Power Prices Promise Both Doom and Riches" *Bloomberg News* (16 February 2021), online: Bloomberg <www.bloomberg.com/news/articles/2021-02-16/skyrocketing-texas-power-prices-may-enrich-some-bankrupt-others>.

Nevertheless, industry participants are moving forward with arbitrage-oriented energy storage projects in Alberta. For example, TERIC Power Ltd. recently connected standalone banks of Tesla lithium-ion batteries to ATCO's distribution system in order to capture revenue from arbitrage and the provision of ancillary services.[59]

2. INTEGRATING RENEWABLES

Renewable integration is a commonly cited application for energy storage. Wind and solar are variable renewable energy sources (**VREs**)–electricity is only generated intermittently, when the sun is shining or the wind is blowing. Energy storage systems are one way to mitigate the variability and instability associated with VREs.

Modern power grids meet demand using a combination of "peaking" and "baseload" resources. Baseload resources always run at or near their rated capacities and provide generation to meet the minimum level of demand on the electrical grid over a given timespan. Common baseload resources in Alberta include coal and natural gas.[60] Peaking resources satisfy swings in demand above the minimum served by the baseload resources. Peaking resources are dispatchable, meaning they can be quickly ramped up to meet demand. The most common peaking resource in Alberta is natural gas,[61] although energy storage and its fast response times could potentially replace gas peakers with VREs.[62]

VREs like wind and solar, however, are classified as "intermittent resources". They are non-dispatchable and do not offer a consistent electricity source. Consumers obviously do not want their access to electricity to be weather dependent, a point that makes for a common criticism of VREs.[63]

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[59] "eReserve Battery Storage Project" (last visited 8 April 2021), online: TERIC Power Ltd <https://ereserve-project.com/>; "The AUC approves largest battery storage installation in Canada" (14 October 2020), online: Alberta Utilities Commission <www.auc.ab.ca/Pages/AUC%20Stories/ereserve-battery-energy-storage-power-plants.aspx>..

[60] Cameron Hughes et al, "Earth, Wind, and Fire: Power Infrastructure in Alberta's New Age" (2017) 55:2 Alta Rev 439 at 441.

[61] Ibid.

[62] "Applications of Energy Storage" (last visited 8 April 2021), online: Energy Storage World Forum <energystorageforum.com/energy-storage-technologies/applications-of-energy-storage>.

[63] During Texas' recent electricity crisis, for instance, some commentators argued the state's catastrophic blackouts were caused by frozen wind turbines and called on Texas to rollback its reliance on wind power. While data from ERCOT (Texas' system operator) suggests the failure of natural gas generation was a much greater factor in Texas' blackouts than frozen wind turbines, the state's electricity crisis does highlight that consumers not only expect stable power, but rely on it for necessities, from accessing clean water to heating their homes to fueling their vehicles. See "Fact check: The causes for Texas' blackout go well beyond wind turbines" *Reuters* (19 Feb 2021), online: Reuters <www.reuters.com/article/uk-factcheck-texas-wind-turbines-explain-idUSKBN2AJ2EI>. As one commentator who "knows[s] a lot about wind" put the

The weather-dependent nature of VREs is thus a real obstacle to high levels of integration. And high rates of intermittent resources increase system variability to a level that creates technical challenges in managing the balance between electricity supply and demand.[64]

These technical challenges relate to net demand volatility. Net demand, equal to load minus variable generation,[65] must always be equal to supply, and Alberta's increasing amount of wind generation has accordingly increased intra-day and -hour net demand volatility.[66] In 2018, the AESO forecast net demand volatility to grow by about 5% annually until 2030 as a result of more VRE capacity.[67]

Greater net demand volatility means larger and more frequent ramps.[68] In other words, system flexibility—"the ability of the power system to quickly adapt to changes in power supply and demand"[69]—must increase. Energy storage can provide this flexibility in two ways. First, as discussed below, energy storage can provide regulating reserve services to balance dispatched energy and net demand.

Second, energy storage is dispatchable and can be used to "firm up" the variability of intermittent resources and reduce net demand volatility.[70] Essentially, this involves co-locating a storage system with an intermittent resource, so that the storage system charges during off-peak hours or with excess supply. The storage device discharges when pool prices are higher, demand increases, or adverse

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criticism, ""You know, Hillary wanted to put windmills all over the place. Let's put up some windmills -- when the wind doesn't blow, just turn off the television darling, please. There's no wind -- please turn off the television quickly!"": Brett Samuels, "Trump mocks wind power: 'When the wind doesn't blow, just turn off the television'" (20 March 2019), online: *The Hill* < https://thehill.com/policy/energy-environment/434989-trump-mocks-wind-power-when-the-wind-doesnt-blow-just-turn-off-the>.

[64] Chaouki Regoui et al, "Canadian Energy Storage Report: 2017 Case Study for the Alberta Market" (last modified 30 May 2020) at 62, online (pdf): National Research Council of Canada <nrc-publications.canada.ca/eng/view/ft/?id=e4660701-e417-4ab9-8f3b-e1358e372511>.

[65] The AESO generally treats non-dispatchable VREs as negative demand.

[66] Shaffer *supra* note 4 at 4; Dennis Frehlich, "Dispatchable Renewables and Energy Storage" (3 October 2018), online (pdf): Alberta Electric System Operator <www.aeso.ca/assets/Uploads/Oct-3-2018-DRS-Stakeholder-Session-FINAL.pdf> [**Dispatchable Renewables**].

[67] Dispatchable Renewables, *ibid* at 22.

[68] *Ibid* at 23.

[69] Claudia Pavarini, "Battery storage is (almost) ready to play the flexibility game" (7 February 2019), online: IEA <https://www.iea.org/commentaries/battery-storage-is-almost-ready-to-play-the-flexibility-game>.

[70] An intermittent resource can be made to have the same reliability as a conventional generating unit if the resource's output is "firmed up" with energy storage. See Doluweera, Rahmanifard and Ahmadi, *supra* note 45 at 59.

conditions interrupt other sources of electricity generation.[71] This reduces net demand volatility by transforming a non-dispatchable[72] VRE into a dispatchable resource that the AESO can monitor and control to support power delivery and balancing.

The Canada Energy Research Institute predicted the levelized cost of energy (**LCOE**) of "firmed up" intermittent resources in Alberta would decline from $0.19-0.23/kWh in 2020 to $0.14-0.15/kWh in 2040.[73] While that is well above the LCOE for conventional natural gas generation ($0.06-0.10/kWh in most provinces), it may become competitive with other zero-emission energy sources by 2040.[74]

Indeed, renewable VREs are forecasted to make up an increasing portion of Alberta's generation mix. As of 2020, Alberta's generation by capacity consisted of 50% natural gas, 31% coal, 11% wind, 6% hydroelectric, 1% solar and 1% other.[75]. Yet the province has committed to phasing out coal-fired generation with natural gas and renewables by 2030.[76] Making up some of the short-fall caused by retiring coal, the AESO currently projects that solar and wind will increase from present levels to account for about 20% of generation capacity by 2030.[77] In addition the AESO has forecasted, in its long term transmission planning reference case, that "all of approximately 5,275 MW of coal-fired capacity will be converted to natural gas-fired generation, beginning in the year 2021."[78] In sync with

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[71] A notable example is the Hornsdale Power Reserve in south Australia, a lithium-ion battery system with a nameplate capacity of 150 MW. The Power Reserve is co-located with the Hornsdale Wind Farm and prevents load shedding when wind speed drops (Marija Maisch, "South Australia's Tesla big battery saves $40 million in grid stabilization costs", *PV Magazine* (5 December, 2018), online: PV Magazine <www.pv-magazine.com/2018/12/05/south-australias-tesla-big-battery-saves-40-million-in-grid-stabilization-costs/>.

[72] Technically, the AESO considers *all* 5 MW or greater generating assets "dispatchable". Here, "non-dispatchable" is equivalent to what the AESO considers "non-controllable".

[73] Doluweera, Rahmanifard and Ahmadi, *supra* note 45 at 53. The LCOE refers to the average price an electricity generator must receive for each unit it generates over the generator's lifetime to break even. LCOE enables cost comparisons between different technologies. For more, see Canada Energy Regulator, "Canada's Adoption of Renewable Power Sources – Energy Market Analysis" (29 Sep 2020), online: Government of Canada <www.cer-rec.gc.ca/en/data-analysis/energy-commodities/electricity/report/2017-canadian-adoption-renewable-power/canadas-adoption-renewable-power-sources-energy-market-analysis-introduction.html>

[74] Doluweera, Rahmanifard and Ahmadi, *supra* note 45 at 53.

[75] "Electricity in Alberta - 2020 AESO Annual Market Statistics" AESO (2020), online.

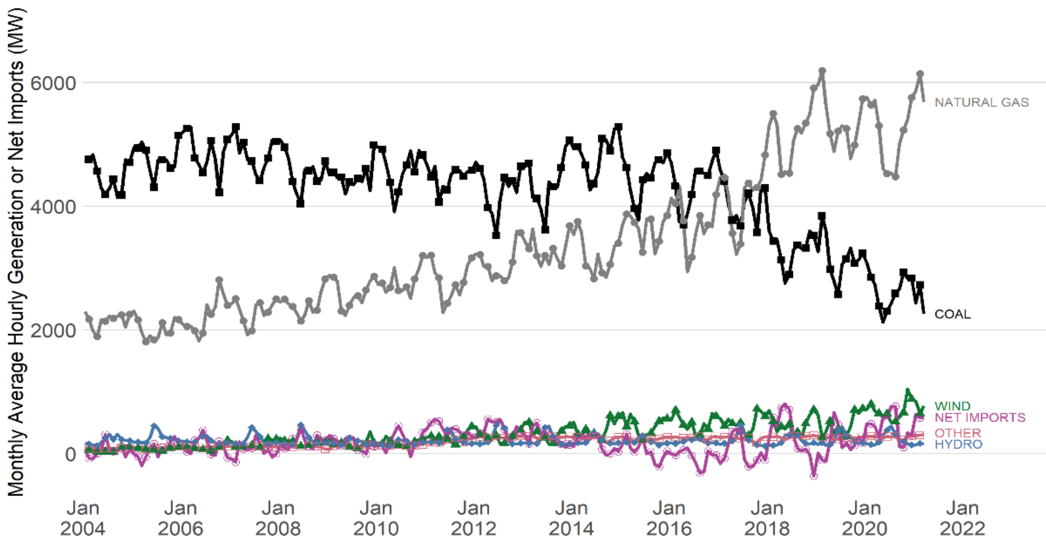
[76] "Alberta set to retire coal power by 2023, ahead of 2030 provincial schedule", *BNN Bloomberg* (4 December 2020), online: Bloomberg <www.bnnbloomberg.ca/alberta-set-to-retire-coal-power-by-2023-ahead-of-2030-provincial-schedule-1.1531933>, and Government of Alberta, "Alberta's Climate Leadership Plan: Progressive Climate Policy" (September 2018), online: < https://open.alberta.ca/dataset/428e517b-3bd4-4d3d-b197-b0233c85647e/resource/f23497a3-6208-41d6-84da-c44416e1676b/download/investorconfidenceclimateleadershipplanfactsheet.pdf>.

[77] "AESO 2019 Long-term Outlook*"* (September 2019) at 23, online (pdf): Alberta Electric System Operator <www.aeso.ca/assets/Uploads/AESO-2019-LTO-updated-10-17-19.pdf>.

[78] "AESO 2020 Long-term Transmission Plan" AESO (January 2020), online.

this forecast by the AESO, a shift from coal toward natural gas and renewables in Alberta is already happening, as can be seen in Figure 1 below.

Figure 1:
Monthly Average Hourly Generation by Fuel Type[79]



Storage systems may be especially significant in Alberta for managing intermittency problems associated with the shift to renewables for two reasons. First, Alberta has limited options for diversifying its renewable sources. Ideally, renewable assets should be dispersed throughout the grid and include more flexible, less weather-dependent resources, like hydro. Alberta, however, lacks adequate hydro resources.[80] And the ideal locations for wind and solar generation are concentrated in southwest Alberta.[81] A windless day in Pincher Creek idles most of the province's wind turbines.

Second, Alberta has relatively few interconnections with neighbouring jurisdictions. In Alberta, generation available through interconnections total less than 10% of the province's peak load. By contrast, California, with 40% renewable generating capacity, relies on interconnections for 33% of its

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[79] Andrew Leach, "not for long…" (7 April 2021 at 22:34), online: *Twitter* <twitter.com/andrew_leach/status/1380016284373458946> and "it's AESO supply data, scraped via NRGStream, and I did the aggregation up to generation by fuel and made the graph." (7 April 2021 at 22:45), online: *Twitter* <twitter.com/andrew_leach/status/1380018895356977153?s=20>.
[80] Shaffer, *supra* note 4 at 6.
[81] van Kooten, Withey and Duan, *supra* note 5 at 199.

supply.[82] In principle, Alberta can increase its interties with British Columbia to access hydroelectric resources, but the provinces have struggled to cooperate on energy developments.[83]

Apart from renewables, energy storage may also have a role firming up thermal units relying on natural gas. In Texas, natural gas is the state's primary electricity source (as is the case in Alberta). During the state's 2021 electricity crisis, nearly 40% of the generation from gas went offline as gas pipelines froze and generators could not access gas to power their plants.[84] While Alberta's infrastructure is obviously much better equipped to handle the cold,[85] Texas' crisis illustrates that electricity systems that are heavily reliant on natural gas generation are vulnerable to gas supply challenges. Storage can provide a backup of electricity when gas supplies are interrupted, due to extreme weather events or otherwise.

3. MITIGATING THE ALBERTA WIND DISCOUNT

A specific example of the foregoing is using storage to mitigate a side effect of Alberta's energy-only market[86] that acts as an obstacle to renewable investment: the "wind discount". This refers to the low price for wind-generated electricity relative to the prices paid for other forms of generation.

Two factors mainly account for the wind discount. First, Alberta's wind farms are disproportionately concentrated in the southwest region of the province. As a result, a large portion of Alberta's wind generation comes online at the same time. Given that wind operators have few variable costs (the wind is free), they offer their electricity at $0/MWh and are inevitably dispatched. While the pool price rarely settles at $0/MWh, the flood of wind-generated electricity depresses pool prices.[87]

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[82] Shaffer, *supra* note 4 at 6.
[83] van Kooten, Withey and Duan, *supra* note 5 at 201.
[84] Alex Gilbert & Morgan Bazilian, "The Texas electricity crisis and the energy transition" *Utility Dive* (19 February 2021), online: Utility Dive <www.utilitydive.com/news/the-texas-electricity-crisis-and-the-energy-transition/595315/>.
[85] Joshua Rhodes & Blake Shaffer, "Lessons for Alberta from the Texas power blackout" *CBC News* (17 February 2021), online: CBC <www.cbc.ca/news/canada/calgary/texas-power-outages-alberta-1.5917052>.
[86] Alberta has an energy-only market, which means generators are "paid for the electricity they produce based solely on the wholesale price of electricity". In contrast, in a capacity market, generators are paid based on their ability (or capacity) to produce electricity and for the electricity they produce. See Matt Ayres, "Electricity Market Design: Energy-Only v. Capacity Markets" (1 August 2019), online: University of Calgary School of Public Policy <www.policyschool.ca/electricity-market-design-energy-only-v-capacity-markets/>.
[87] See, for example, the Market Surveillance Administrator's 2020 Q3 report, where they stated that there about 4083 minutes of supply surplus (i.e., $0 pool price) in 2020 to the end of Q3: "Quarterly Report for Q3 2020" (10 November 2020), online: <https://www.albertamsa.ca/assets/Documents/Q3+2020+Quarterly+Report.pdf>.

Second, wind generation is not correlated with periods of peak demand. Wind generation in Alberta occurs more at night and in summer, when pool prices are already lower. This means wind farms tend to have a low "capture rate", or the percentage of the average pool price that a generator receives for its electricity.[88]

Storage could mitigate the wind discount, as it provides wind facilities the opportunity to offer their electricity in periods of peak demand.[89] First, off-peak wind generation is stored in batteries co-located with a wind farm. Then, at times of peak demand, the battery discharges to capitalize on higher pool prices. This strategy is known as time-shifting, and is essentially pool price arbitrage.

Time-shifting also reduces losses from both transmission-related and economic curtailments. A transmission-related curtailment may result from an AESO directive to curtail generation when certain transmission constraints arise on the grid (as the AESO will only permit a generator to dispatch if the transmission line to which the generator is connected is functioning and has available capacity). Similarly, an economic curtailment may arise under the AESO's supply surplus rules when the simultaneous flood of wind-generated electricity results in electricity supply outstripping transmission capacity.[90] Curtailment may also occur due to a lack of demand.[91] Storage provides some relief from curtailment, since generated supply that cannot be dispatched can be stored.[92] When transmission capacity returns, the wind generator can discharge the battery and offer the electricity to the pool, minimizing the quantity of foregone generation (i.e., lost electricity).

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[88] Between 2008 and 2015, for example, wind farms earned 30-35% of the average pool price.

[89] Storage also counteracts dramatic fluctuations in net load curves. Net load refers to the difference between forecasted load (i.e., demand) and the amount of generation from variable renewables like wind. A net load curve plots net load over a given period. When generation from variables drop off, the net curve spikes, meaning non-renewable sources must quickly ramp up generation to meet demand. This can lead to a duck-shaped, see-sawing curve, as in California: "What the duck curve tells us about managing a green grid" (2016), online: California ISO <www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf>. Storage can smooth the net load curve by satisfying load as generation from renewables falls.

[90] Lyseng et al, "System-level power-to-gas energy storage for high penetrations of variable renewables" (25 January 2018) 43:2 Intl J Hydrogen Energy 1 at 2.

[91] Ibid.

[92] Ibid.

B. ANCILLARY SERVICES

The AESO procures ancillary services to ensure that the Alberta Interconnected Electric System (**AIES**) is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.[93] Ancillary services are required to maintain the stability of the transmission system, and include fast frequency response, transmission must-run service, black start services, load shed service and operating reserves, among others.[94] Storage can provide some of these ancillary services as follows:

Black Start Services	Following a blackout, storage can be used to restart generation that cannot self-start.
Load Shed Services	Storage can be used to absorb excess load to compensate for load imbalances.
Operating Reserve	Storage can support three forms of operating reserve: 1. Regulation: Storage can provide instantaneous power to balance the lag between load and supply from slower-starting generation. 2. Spinning: Normally, this refers to generators that are synchronized to the grid (i.e., the turbine is "spinning" but not producing electricity) to quickly ramp up to meet sudden imbalances in load and supply. Storage can fulfill this role by discharging electricity for a similar duration and response time as conventional "spinning" generators. Spinning is the fastest form of contingency reserve. 3. Non-spinning (or supplemental): Reserves that are not synchronized to the grid. They are not as fast acting.

The AESO recently announced the Fast Frequency Response Technology Pilot Project to procure reliability services.[95] Fast frequency response (**FFR**) is a "fast-acting transmission reliability service facilitating the arrest and recovery from frequency decay caused by the sudden loss of imports on the British Columbia / Montana interties", used to prevent outages if intertie supply is disrupted.[96] Under

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[93] *Electric Utilities Act*, SA 2003, c E-5.1 [*EUA*], s 1(1)(b).
[94] "Ancillary Services", AESO, online. For more on the definitions of the uses, see Chaouki Regoui et al, "Canadian Energy Storage Report: 2017 Case Study for the Alberta Market", National Research Council Archives (National Research Council of Canada, 2020) at 8 – 13, online.
[95] "Joint Stakeholder Engagement Session on Energy Storage and Distributed Energy Resources (DER)" (14 October 2020) at 32, online (pdf): Alberta Electric System Operator <www2.auc.ab.ca/Proceeding24454/ProceedingDocuments/24454_X%5b%5d_Decision24454-D01-2019-WesternSustainabl_0059.pdf>.
[96] Ibid at 30.

this project, the AESO will procure 20-40 MW of generation from any "new technology" able to meet the technical requirements.[97] On top of FFR revenue, selected service providers will also be able to participate in the energy and operating reserves markets.[98]

These services do not always require the provision of energy to the grid, but are still compensated in exchange for the system benefit provided. Ancillary services may be a more profitable use of energy storage than pool price arbitrage.

For instance, some trends in the value of storage resources were recognized by Elshurafa et al. in their review of valuation studies of energy resources.[99] They noted that "storage technologies, generally, find their maximum value in providing regulation reserves, followed by providing spinning reserves, and finally by providing energy/arbitrage."[100] Of the three services noted by Elshurafa et al. the two most valuable were both system services. In Alberta, Natural Resource Canada's 2018 study[101] found a 10 MW lithium-ion battery with a 2 hour duration had the highest return on investment over the 14-year forecast period when compared to compressed air and pumped hydro storage. The relatively higher return on investment was attributed to the battery's ability to receive revenue from providing frequency regulation services in the ancillary services market.[102]

As of 2020, around a third of U.S. storage projects (131/373) were used for electric bill management or peak shaving, but the largest proportion of installed capacity (189/958 MW) was used for frequency regulation.[103] Such skewing of large, utility-scale storage installations towards the provision of ancillary services, rather than energy services, perhaps suggests that the market anticipates greater value in using energy storage for the provision of system services.

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[97] Ibid at 31.
[98] Ibid.
[99] Amro E Elshurafa, "The Value of Storage in Electricity Generation: A qualitative and quantitative review" (2020) 32 J Energy Storage at 4.
[100] *Ibid* at 10; Flowerday, *supra* note 24 at 44: "Today, energy storage provides the most value to renewable integration in the management of short-term variability on the power grid."
[101] Introduced above at Regoui, *supra* note 64.
[102] For a definition of frequency regulation, see "Frequency Regulation" *ESA Blog* (24 October, 2013), online: Energy Storage Association <energystorage.org/frequency-regulation/>. Regoui *supra* note 64 at 65.
[103] Mokhtar Tabari, "Paying for Performance: The Role of Policy in Energy Storage Deployment"(2020) 92 Energy Economics at 3, Figure 2.

Not only does storage provide ancillary services profitably, it may provide them more profitably than traditional generation. When providing ancillary services, an advantage that storage has over traditional generation is its highly scalable and modular nature. Because of these two features, storage does not require massive installations to provide the entire range of utilities services that it is capable of. Firm (peaking) capacity, contingency (non-spinning) reserves and transmission and distribution benefits—the ancillary services that require the greatest minimum capacities—still only require 10 MW of installed capacity to be viable.[104] As some storage technologies, such as batteries, are scalable and can be installed at the same unit price regardless of size, the same level of ancillary services can be more cheaply provided than from traditional generation, which may require a larger minimum monetary and capacity investment to provide similar services.[105]

C. NON-WIRES ALTERNATIVES

Non-wires alternatives (**NWAs**) are grid investments or projects using non-traditional transmission and distribution solutions to defer or replace the need to build wire infrastructure.[106] Energy storage can be deployed as an NWA if it is added at strategic points along the transmission or distribution system to keep loads below a specified maximum, delaying the need for system upgrades. On top of cost savings from deferred or avoided wire build-out, using energy storage as a NWA could have additional value if the regulatory framework permits the same energy storage to provide energy or ancillary services.[107]

FortisAlberta's Waterton battery energy storage system[108] provides an example of storage deployed as a NWA. The Hamlet of Waterton is served by one feeder with no backup during outages, and the battery storage system was proposed to provide up to 5.2 MWh of backup energy (or, on average, about 9 hours of supply each year) to the Hamlet.[109] With an expected lifespan of 10 to 15

[104] Elshurafa, *supra* note 99 at 3, Table 1.
[105] Jamal Faraji et al, "A Comparative Study between Traditional Backup Generator Systems and Renewable Energy Based Microgrids for Power Resilience Enhancement of a Local Clinic" (2019) 8 Electronics 1485 at 1501 and 1502.
[106] DSI Inquiry *supra* note 3 at para 144, *infra* fn 114.
[107] "Applications of Energy Storage", *supra* note 62.
[108] Discussed below in VI and VII.A.2.
[109] AUC Proceeding 26061, Exhibit 1 (FortisAlberta Inc. Waterton Battery Energy Storage System Letter of Inquiry) at PDF 2.

years,[110] the battery storage system is estimated to cost $4.2 million, with about 60% being externally funded by government partners.[111] FortisAlberta evaluated a wires alternative—36 km of new or upgraded distribution line—estimated to cost $7.9 million.[112]

Microgrids are another potential, non-market based use for energy storage, particularly in remote communities without connection to the electricity grid.[113] For example, about 170 Indigenous communities in Canada are not connected to the grid.[114] These communities generally rely on diesel-powered generators, although renewables are increasingly prevalent.[115] Storage can be leveraged to enhance reliability in microgrids, balancing the variability of intermittent resources and reducing reliance on diesel-powered generation without the need to construct wires infrastructure.[116]

D. LOAD CUSTOMER APPLICATIONS

Load customers can also deploy energy storage. Some load customers that require continuous power, like hospitals, can use energy storage as back-up.[117] But the end goal for most load customers using energy storage is to reduce the customer's electricity bill. First, time-of-use bill management can be used to store electricity when the pool price is low for use during peak times of the day. Second, residential and small commercial customers with solar installations can draw even less from the grid if the solar supply is paired with energy storage. Third, Alberta uses a 12 hr coincident peak demand

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[110] *Ibid*, PDF 3.

[111] Waterton Battery Decision, *supra* note 18 at paras 5 & 8; AUC Proceeding 26061, Exhibit 12 (FAI-AUC-2020DEC03-002) at PDF 3.

[112] *Ibid,* para 8.

[113] A microgrid is a group of interconnected loads that acts as a single controllable electricity system, which either operates independently of the main grid periodically or at all times (as with isolated communities. See DSI Inquiry *supra* note 4 at para 179. Alberta's *Isolated Generating Units and Customer Choice Regulation,* Alta Reg 165/2003, requires a distribution system owner to provide service to "isolated communities", which are communities where interconnection to Alberta's main grid is determined by the AUC to be uneconomic.

[114] Milosz Zemanek , Valerie Helbronner & Henry Ren, "Canada: Energy Storage Development: Opportunities For Remote Indigenous Communities" (27 January 2021), online (blog): Mondaq <www.mondaq.com/canada/renewables/1030246/energy-storage-development-opportunities-for-remote-indigenous-communities>.

[115] *Ibid*.

[116] Beginning in 2019, Fort Chipewyan in Northern Alberta installed a 1,600 kWh BESS as part of new microgrid operations. The new operations, which also include new solar panels, will replace 800,000 litres of diesel fuel annually when fully operational, leading to a 25% reduction in diesel consumption. See "Fort Chipewyan: The Road to Energy Independence" (19 June 2020), online: ATCO Electric <www.atco.com/en-ca/about-us/stories/fort-chipewyan--the-road-to-energy-independence-.html>.

[117] "Applications of Energy Storage" *supra* note 62.

charge to recover transmission costs, and commercial and industrials customers who can use storage to avoid these 12 hours can realize significant savings.[118]

Apart from back-up, load customer applications' raise uneconomic bypass issues under the current tariff structures.[119] Namely, under all three of the bill management uses described above, uneconomic bypass of the AIES occurs because a customer's decision to install individual energy storage to lower its bill shifts the recovery of the largely fixed costs of the electric transmission and distribution systems to other customers.[120]

V. ECONOMICS OF ENERGY STORAGE

The prospects for profitable applications of energy storage improve each year as costs (particularly, lithium-ion battery costs) fall. Driven by global demand for electric vehicles, investment in battery-pack design has dramatically lowered costs for lithium-ion batteries, the storage technology representing 90% of the short-duration storage market.[121]

The LCOE for lithium-ion battery systems has fallen from around USD $1,100/kWh in 2010 to USD $137/kWh in 2020, a decline of 89% in real terms.[122] The drop in battery costs has created new energy storage opportunities and applications on a grid scale.

And the decline in costs appears set to continue with an average LCOE of USD $100/kWh projected by 2023.[123] Battery pack prices are forecasted to decline even as demand for their base commodities increases. Commodity prices for constituent metals, like lithium and cobalt, have increased with

[118] Ibid.
[119] DSI Inquiry, *supra* note 3 at para 242.
[120] *Ibid* at, para 97. In other words, "since rates must recover total embedded system costs, a dollar that is not collected through one customer or billing component must be recovered from another customer or billing component."(at para 104).
[121] David Frankel, Sean Kane & Christer Tryggestad, "The new rules of competition in energy storage"(8 June 2018), online: McKinsey & Company <www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/the-new-rules-of-competition-in-energy-storage#>.; Lazard and Roland Berger, "Lazard's Levelized Cost of Storage Analysis – Version 6.0" (2020) at 5, online (pdf): Lazard <www.lazard.com/media/451566/lazards-levelized-cost-of-storage-version-60-vf2.pdf>.
[122] "Battery Pack Prices Cited Below $100/kWh for the First Time in 2020, While Market Average Sits at $137/kWh" (16 December 2020), online: Bloomberg New Energy Finance <about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/>.
[123] Ibid.

demand from storage manufacturing. Yet increases in the price of these commodities is not expected to significantly affect battery pack prices.[124]

Along with the fall in prices, global energy storage deployment has jumped in the past five years.[125] Between 2014 and 2018, installed energy storage went from a global total of 400 MW/year to 3,100 MW in 2018. Bloomberg New Energy Finance forecasts the global energy storage market, excluding pumped hydro, will attract USD $620 billion and grow to a cumulative installed capacity of 942 GW by 2040.[126]

Lazard, a financial advisory and asset management firm, has looked at the levelized cost of energy storage across multiple use cases for several years. In its latest report, released in 2020, Lazard found storage costs had declined in 2019 across most use cases and technologies. For instance, its 2019 report found standalone wholesale energy costs at rates of USD $165-325 /MWh compared to USD $132-250 /MWh for the same use case in its 2020 report.[127] Lithium-ion technologies, in particular, showed sustained cost declines on both a $/MWh and $/kW-year basis. Cost declines were more pronounced for storage modules in particular, rather than system components or ongoing operations and maintenance expenses.[128]

Through competitive costs, storage is now poised to become a disruptive force in electricity markets around the world over both the short- and long-term.[129]

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[124] Logan Goldie-Scott, "A Behind the Scenes Take on Lithium-ion Battery Prices" (5 March 2019), online: Bloomberg New Energy Finance <about.bnef.com/blog/energy-storage-620-billion-investment-opportunity-2040/#_ftn1>.

[125] Doluweera, Rahmanifard and Ahmadi *supra* note 45 at 1.

[126] "Energy Storage is a $620 Billion Investment Opportunity to 2040", Bloomberg New Energy Finance (6 Nov 2018), online. See also Doluweera, Rahmanifard and Ahmadi, *ibid* at 15.

[127] Jules Scully, "Lazard's LCOS 6.0: Solar-plus-storage becoming 'increasingly competitive', *Energy Storage News* (22 Oct 2020), online: <www.energy-storage.news/>; "Lazard's Levelized Cost of Storage Analysis – Version 6.0", online: Lazard <https://www.lazard.com/media>.

[128] Scully, ibid.

[129] In the United States, a Bloomberg New Energy Finance report found that solar-plus-battery storage is becoming competitive with the lowest-cost natural gas generation (combined cycle gas turbines) in states like California, where gas prices are relatively high. The report concluded storage-plus-solar (and other renewables) represented "a zero-emissions threat to gas, which is currently the workhorse of the U.S. power generation fleet."("How PV-Plus-Storage Will Compete with Gas Generation in the US" (23 November 2020), online: Bloomberg New Energy Finance <about.bnef.com/blog/how-pv-plus-storage-will-compete-with-gas-generation-in-the-u-s/#:~:text=Our%20results%20show%20that%20PVS,environmentally%20friendly%20than%20gas%20peakers>) Globally, Bloomberg New Energy Finance found the LCOE for batteries with a duration below two hours was already cheaper for peak shaving than open cycle gas turbines, traditionally the conventional technology for that purpose (Andy Colthorpe, "BloombergNEF: Already cheaper to install new-build battery storage than peaking plants," *Energy Storage News* (30 April

VI. OVERVIEW OF ALBERTA ENERGY STORAGE PROJECTS

There are several energy storage projects already in place or in development in Alberta, highlighting that developers already see value in energy storage within the province. Table 1 below describes some permitted or planned energy storage projects in Alberta for which information is publicly available. There are no doubt more energy storage projects in the pipeline. The April 2021 AESO Project List, for example, lists 11 other projects with a storage component seeking new or altered transmission access. Eight of the 13 total projects on the AESO Project List are listed as hybrid solar and storage projects, explaining why the 1,099 MW of total supply transmission capacity requested far outpaces the 159 MW of total demand transmission capacity requested.

TABLE 1:
DESCRIPTION OF PERMITTED AND PLANNED ENERGY STORAGE PROJECTS IN ALBERTA

Project Name	Status	Description
Canyon Creek Pumped Hydro[130]	Approved by the AUC, construction beginning in Spring 2021	A 75 MW project pumped hydro facility located near Hinton, Alberta, owned, constructed and operated by Turning Point Generation.[131] The project will have 3 x 25 MW turbines and uses land around and in an abandoned coal mine as an upstream reservoir.
Empress Solar Power Plant[132]	Approved by the AUC, no in service date announced	A 39 MW solar power plant with 2.5 MW of integrated lithium-ion battery storage.
ENMAX Midstream Industrial Solar + Storage Project[133]	In development	Lithium-ion batteries installed at Keyera Corporation's Rimbey gas plant.
Fort Chipeweyan Microgrid Energy Storage[134]	In service Fall 2020	A 600 kW solar farm paired with a 1,700 kW battery storage network and a

2020), online: Energy Storage < https://www.energy-storage.news/news/bloombergnef-lcoe-of-battery-storage-has-fallen-faster-than-solar-or-wind-i#>

130 "Canyon Creek Project eyes 2021 build", *The Hinton Voice* (17 September 2020), online: The Hinton Voice <https://hintonvoice.com/2020/09/canyon-creek-project-eyes-2021-build>; *Re Turning Point Generation* (August 2, 2018), 22934-D01-2018, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2018/22934-D01-2018.pdf>.

131 *Re Turning Point Generation* (December 21, 2018), 22934-D02-2018, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2018/22934-D02-2018.pdf>.

132 *Re Aura Power Renewables Ltd* (October 3, 2019), 23580 – D01 – 2019, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/23580-D01-2019.pdf> [**Empress Solar Decision**].

133 "ENMAX Midstream Industrial Solar + Storage Project" (last visited April 7, 2021), online: Emissions Reduction Alberta <eralberta.ca/projects/details/enmax-midstream-industrial-solar-storage-project/>.

134 Cision, "ATCO Completes Canada's Largest Off-Grid Solar Project in Partnership with Three Alberta Indigenous Nations"

Project Name	Status	Description
		community microgrid designed to control the solar farm and distribution.
Alberta-Saskatchewan Intertie Storage (ASISt)[135]	In development	A new 150 MW inter-tie between Saskatchewan and Alberta, paired with compressed air energy storage. The CAES facility will have between 135–160 MW of generating capacity.
E.L. Smith Solar Power Plant Battery[136]	Planned in service Spring 2022	A 4 MW battery added to an existing 12 MW power plant.
FortisAlberta Inc. Waterton Battery Storage System[137]	No in-service date announced, approved by the AUC	A lithium-ion battery with a capacity of 1.6 MW to provide a back-up energy source to the hamlet of Waterton.
TERIC Power Ltd eReserve1 Battery[138]	In service December 2020	A bank of 14 1.5 MW lithium-ion batteries grouped into two discrete units sited about 2 km south of the village of Rycroft.
TERIC Power Ltd eReserve2 Battery[139]	In service Summer 2021	A bank of 14 1.5 MW lithium-ion batteries grouped into two discrete units sited about 2 km south of the village of Rycroft.
TERIC Power Ltd eReserve3 Battery[140]	In development	A 20 MW battery energy storage plant sited 10 km northeast of Clairmont.
Drumheller Solar and Battery Storage Project[141]	In service May 2021	A 13.5 MW solar power plant paired with a lithium-ion battery array with a capacity of 8 MW.

(November 18, 2020), online: News Wire < www.newswire.ca/news-releases/atco-completes-canada-s-largest-off-grid-solar-project-in-partnership-with-three-alberta-indigenous-nations-872713550.html>; *Re Three Nations Energy GP Inc* (January 15, 2020), 24856-D01-2020, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2020/24857-D01-2020.pdf>.

135 "Alberta Saskatchewan Intertie and Storage (ASISt) Project" (last visited March 14, 2021), online: Rangeland Engineering <www.rangelandeng.com/alberta-saskatchewan-intertie-and-storage-asist-project/>.

136 *Re EPCOR Water Services Inc* (August 27, 2020), 25770-D01-2020, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2020/25770-D01-2020.pdf>; "Proposed Energy Storage System (BESS) Project", online: EPCOR <www.epcor.com/products-services/infrastructure/construction-projects/el-smith-solar-farm/Pages/battery-project.aspx>.

137 Waterton Battery Decision, *supra* note 112.

138 *Re TERIC Power Ltd* (April 6, 2020), 25205-D01-2020, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2020/25205-D01-2020.pdf > [**TERIC Battery 1 Decision**]; Liam Verster, "Rycroft the first recipient of new renewable energy storage project" *Everything Grande Prairie* (October 28, 2020), online: Everything Grande Prairie <everythinggp.com/2020/10/28/rycroft-the-first-recipient-of-new-renewable-energy-storage-project-2/>.

139 *Re TERIC Power Ltd* (August 21, 2020), 25691-D01-2020, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2020/25691-D01-2020.pdf>.

140 TERIC Power Ltd AUC Application 26221-A001, published January 18, 2021.

141 *Re Drumheller Solar Corp* (April 6, 2020), 25234-D01-2020, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2020/25234-D01-2020.pdf> [**Drumheller Solar and Battery**

Project Name	Status	Description
Crossfield Energy Centre Hybrid Fuel Project[142]	Under construction, no in service date announced	A 10 MW lithium-ion battery array paired with an existing natural gas turbine generator.
WindCharger Battery Storage[143]	In service October 15, 2020	A 10 MW lithium-ion battery array paired with the utility grade Summerview wind farm.
Saddlebrook Solar and Storage Project[144]	In development	A new 10 MW solar plant paired with a 5 MW flow battery array.

More projects are likely to follow as battery prices continues to decline. In its 2018 study, NRC forecasted rates of Alberta energy storage adoption between 2017 and 2030. The report found that Alberta's adoption rate is highly sensitive to capital costs, as a 40% decline in energy storage prices increased adoption by 60%.[145] In total, the NRC estimated Alberta would have 1,152 MW of storage by 2030, but this amount could be up to 1,860 MW if storage costs fall further than forecasted.[146]

Notwithstanding declining battery prices, the economic viability of energy storage may depend on the regulatory framework in place, which we discuss in the next section.

VII. REGULATORY TREATMENT OF ENERGY STORAGE IN ALBERTA

This section outlines the regulatory framework applicable to energy storage, and highlights potential regulatory barriers and opportunities. In this regard, we agree with the AUC's conclusions in the *Distribution System Inquiry Final Report*, as referenced in the Introduction, that energy storage:

Decision].

142 *Re ENMAX Generation Portfolio Inc* (February 5, 2020), 25230-D01-2020, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2020/25230-D01-2020.pdf>

143 "TransAlta Renewables Announces Commercial Operation of WindCharger, Alberta's First Utility Scale Battery Storage Project" (October 15, 2020), online: TransAlta Renewables Inc <www.transaltarenewables.com/2020/10/15/transalta-renewables-announces-commercial-operation-of-windcharger-albertas-first-utility-scale-battery-storage-project>; *Re Western Sustainable Power Corp* (November 7, 2019), 24454-D01-2019, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/24454-D01-2019.pdf> [**Windcharger Battery Decision**].

144 "Saddlebrook Solar and Storage" (last visited 7 April 2020), online: Canadian Electricity Association <electricity.ca/lead/centre-of-excellence/saddlebrook-solar-storage/>.

145 Regoui, supra note 64 at ii.

146 Ibid at 35.

(i) faces regulatory and policy barriers to deployment, and (ii) could significantly alter Alberta's existing regulatory framework.[147]

The AESO came to substantially similar conclusions in its *Energy Storage Roadmap*: (i) Alberta's regulatory framework lacks clarity and specificity with regard to energy storage, and (ii) energy storage's unique attributes are not the same as loads or generators.[148] The Alberta Ministry of Energy has also launched an engagement exercise on energy storage; identifying that "energy storage technologies can provide a variety of benefits to Alberta's energy system."[149] In this process, comments were collected, via survey, from April 15-May 14, 2021, and the results are under review. The results of the survey may help "inform possible policy or legislation changes."[150]

Drawing on AUC comments and decisions, we identify several regulatory challenges in this section. To begin, energy storage's capacity to consume and discharge electricity makes it difficult to fit within traditional regulatory definitions. Moreover, under the *EUA,* utilities may not own storage as part of transmission or distribution systems if storage is classified as a generating unit.

The AESO has also proposed changes to the current ISO rules to better reflect energy storage's unique attributes. The only planned change to the tariff treatment of storage that has been announced is modernization of the interruptible "Demand Opportunity Service" rate (**DOS**).[151] At present, DOS allows those connected to the grid to draw additional power above the amount they are contracted for under Rate Demand Transmission Service (**Rate DTS**) on an interruptible and $/MWh basis.[152] While DOS is currently temporary and available only for short term periods when there is available

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[147] DSI Inquiry, *supra* note 3 at para 225.
[148] Energy Storage Roadmap, *supra* note 1 at 3.
[149] "Energy Storage Engagement", Alberta Ministry of Energy (May 17, 2021), online: <Energy storage engagement | Alberta.ca>
[150] *Ibid.*
[151] "Bulk and Regional Tariff Design Stakeholder Engagement Session 5B (Demand and Opportunity Service)", AESO (May 20, 2021) at 6, online: <Session-5B-DOS-Presentation.pdf (aeso.ca)>.
[152] "Bulk and Regional Tariff Design Stakeholder Engagement Session 5 (Demand and Opportunity Service)", AESO (March 25, 2021) at 72, online: <https://www.aeso.ca/assets/Uploads/Presentation-Session-5-March-28.pdf>.

transmission capacity,[153] the AESO is proposing technical changes to expand eligibility and integrate DOS capacity into the energy market bidding system.[154]

A. DEFINING ENERGY STORAGE

Energy storage has unique attributes that are not contemplated in the current regulatory framework governing Alberta's electric system.[155] The ability to both consume and discharge the same electricity means that energy storage squares uneasily with existing definitions that maintain the traditional distinctions between generation, transmission, distribution and load assets. And energy storage's varying applications further add to the uncertainty surrounding energy storage's place in the existing framework.

As parties to the *Distribution System Inquiry* submitted, the lack of an energy storage-specific statutory definition leads to a "lack of clarity and certainty in how, when, where and for what purpose such resources can be legally deployed to meet customer wants and needs at market-based prices".[156]

To date, the AUC has approved energy storage as both a power plant and as part of an electric distribution system. At times, the AUC has also relied on its public interest mandate to approve energy storage facilities as parts of power plants.

That said, further clarity is needed on whether storage may qualify as a "power plant". Practically, storage does not generate power, making this classification an uneasy fit. Relatedly, definitional clarity is needed where storage is used in transmission and distribution systems. For instance, the AUC has treated storage as a distribution system component when used as a back-up supply, a treatment that is seemingly at odds with classifying it as a "power plant". The lack of definitional clarity is leading the AUC to rely on its public interest mandate and broader regulatory powers to interpret the regulatory requirements that apply to energy storage.

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[153] *Ibid*.
[154] Bulk and Regional Tariff Design Stakeholder Engagement Session 5B (Demand and Opportunity Service)", AESO (May 20, 2021) at 78, online: <[Session-5B-DOS-Presentation.pdf (aeso.ca)]>.
[155] DSI Inquiry, *supra* note 3 at para 22.
[156] *Ibid* at para 229.

1. IS AN ENERGY STORAGE SYSTEM A POWER PLANT?

When used for pool price arbitrage, or when discharging generally, energy storage appears to function as a "power plant", as defined under the *Hydro and Electric Energy Act*.[157]

Reference	Definition
EUA, s 1(1)(u), 'generating unit'	*…the component of a power plant that produces, from any source, electric energy and ancillary services, and includes a share of the following associated facilities that are necessary for the safe, reliable and economic operation of the generating unit…*
HEEA, s 1(1)(k), 'power plant'	*…the facilities for the generation and gathering of electric energy from any source…*

The AUC has considered stand-alone battery energy storage facilities, such as the eReserve1 and eReserve2 projects, to fall within the above definitions. In Decision 25205-D01-2020 approving eReserve1, the AUC focused on the conversion of energy, holding:

> Although the *Hydro and Electric Energy Act* and *Electric Utilities Act* do not specifically address battery energy storage as a power plant or a generating unit, the Commission considers that the project, as proposed, is intended to function as a power plant. Both acts provide that a power plant or generating unit can produce electric energy from any source. All power plants convert energy from one type to another; for example, thermal power plants convert thermal energy to electric energy. A battery energy storage facility, when discharging, converts chemical energy to electric energy. And, if the chemical energy that is stored in a stand-alone battery facility was originally derived from electric energy sourced from the AIES, it does not change the fact that the storage facility, when discharging, is generating or producing electric energy from the battery modules. The Commission is therefore satisfied that the project meets the definition of a power plant under the *Hydro and Electric Energy Act*, and notes that this finding is consistent with recent regulatory rulings in other jurisdictions.[158]

This analysis, however, reveals the potential pitfalls of extending existing definitions to cover energy storage. As energy storage proponents have pointed out, energy storage does not *produce*

[157] RSA 2000, c H-16 [***HEEA***].
[158] TERIC Battery 1 Decision, *supra* note 138 at para 23.

electric energy, but *stores* electric energy.[159] Similarly, energy storage provides ancillary services, but through the injection, not production, of electricity.[160]

Another issue that arises from characterizing energy storage systems as "power plants" are concerns surrounding the prohibition on self-supply and export. Subject to limited exemptions, the AUC held in the E.L. Smith decisions[161] that on-site generators cannot both self-supply and export excess electricity to the grid. The AUC's rationale was that the *EUA* requires that (1) electric energy entering or leaving the AIES must be exchanged through the power pool, and (2) persons wishing to receive electric energy must take service from the distribution system (or, at times, the transmission system).

The issue arises if an energy storage system is considered a "power plant" and is charged by a co-located, grid-connected generating unit.[162] If an energy storage system is characterized as a "power plant" that converts energy from a source, and that source is a grid-connected generating unit, it is unclear whether the co-located unit is both self-supplying the energy storage system and exporting excess electricity to the grid.

In our experience, this uncertainty regarding self-supply and export rules has affected potential power plant configurations. For example, query whether a thermal unit that alternates between

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159 Paula McGarrigle, "Renewable Energy and Energy Storage Market Opportunities – Presentation to Bulk and Regional Tariff Team" (November 5, 2020) at 5, online (pdf): Solas Energy Consulting <www.aeso.ca/assets/Uploads/Solas-CanREA-Rate-Design-Presentation.pdf> [**Solas Presentation**].

160 Ibid.

161 See "Self-Supply and Export – Alberta Utilities Commission Discussion Paper" (June 5, 2020) at 31, online (pdf): Alberta Utilities Commission <www.auc.ab.ca/regulatory_documents/Reference/Self-supply%20and%20export%20%E2%80%93%20AUC%20discussion%20paper.pdf>. See also *Re EPCOR Water Services Inc* (February 20, 2019), 23418-2019, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/23418-D01-2019.pdf>; *Re Advantage Oil and Gas Ltd* (April 26, 2019), 23756-D01-2019, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/23756-D01-2019.pdf>; *Re International Paper Canada Pulp Holdings ULC* (June 6, 2019), 24393-D01-2019, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/24393-D01-2019.pdf>; *WCSB Power Generation GP Inc* (June 19, 2019), 24519-D01-2019, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/24519-D01-2019.pdf>; *Re Keyera Energy Ltd* (July 26, 2019), 24126-D01-2019, online: AUC <https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/24126-D01-2019%20(Corrigenda).pdf#search=24126>; *Re Advantage Oil & Gas Ltd* (December 17, 2019), 24674-D01-2019, online: AUC <https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/24674-D01-2019.pdf#search=24674%2DD01%2D2019>.

162 This was largely the configuration put forth for the WindCharger project. Rather than being permitted as a stand-alone power plant, however, the WindCharger battery storage project was permitted as an alteration to the existing Summerview wind power plant (Windcharger Battery Decision, *supra* note 143 at para 1).

supplying energy to the grid and charging an energy storage system is offside self-supply and export limitations (i.e., is the charging "self-supply")? Or, insofar as all power generated is ultimately intended for export (just not at the same time), is the configuration compliant with legislative constraints? Further, do separate points of connection to the grid change either framing?

On this last question, adding another energy storage system between the thermal unit and the grid may avoid self-supply and export issues as the thermal unit never directly injects electricity into the AIES. This configuration potentially benefits from section 2(1)(b) of the *EUA*, which exempts electricity consumed solely by a person solely on property owned or leased by that person from the application of the *EUA*. Based on the eReserve1 analysis above on the conversion of chemical energy to electric energy, the storage system could "consume" all of the thermal unit's output, thereby exempting that output from the self-supply and export prohibitions. That said, such a configuration is inefficient as it results in infrastructure being duplicated to satisfy regulatory requirements. Clarity on the application of self-supply and export rules to energy storage would be a welcome development.

2. IS AN ENERGY STORAGE SYSTEM A TRANSMISSION FACILITY OR PART OF AN ELECTRIC DISTRIBUTION SYSTEM?

When used as a non wires alternative, energy storage may meet the statutory definitions applicable to transmission and distribution systems.

With respect to transmission systems, the AUC has not yet approved an energy storage system as part of a transmission system. Under the *EUA*, the 25 kilovolt voltage level defining a "transmission facility" is higher than the voltages typically found in an energy storage system. That said, energy storage systems may fall within the existing *HEEA* definition of a substation.

Reference	**Definition**
HEEA, s 1(1)(n), 'substation'	*…a part of a transmission line that is not a transmission circuit and includes equipment for transforming, compensating, switching, rectifying or inverting of electric energy flowing to, over or from the transmission line…*

As storage proponents point out, an energy storage system includes equipment for transforming and inverting electric energy flowing to or from a transmission line.[163]

Using energy storage as an NWA in the transmission context, however, faces regulatory restraints. Under section 15(3) of the *Transmission Regulation*, NWAs are only allowed in areas with limited load growth potential or when an NWA is required for reliable service due to the shorter lead time of the NWA, but only "for a specified limited period of time". The *Transmission Regulation* expires on December 31, 2021, and we are watching to see whether these restrictions on the use of NWAs survive. As others have concluded, "legislative amendments may be required for the full range of uses of energy storage assets and technology to be realized."[164]

Turning our focus to distribution, the AUC recently approved FortisAlberta's application for a minor alteration to its distribution system.[165] FortisAlberta's proposed minor alteration was the construction of a battery energy storage system in Waterton Lakes National Park. The battery was proposed as a back-up supply during outages, and will only provide electricity to customers when the local distribution system is islanded from the AIES.

Two aspects of this decision are noteworthy. The first is the issue of regulated entities owning energy storage facilities, which we return to below. The second is the AUC's finding that the energy storage system is a minor alteration to FortisAlberta's distribution system.

On this second point, the AUC provided no analysis on why it was satisfied that constructing the proposed energy storage system amounted to a minor alteration of an electric distribution system. We believe that this may have been a missed opportunity to provide clarity, given that (1) the AUC has found a battery energy storage facility to meet the *HEEA* definition of a 'power plant', and (2) the *HEEA* defines an 'electric distribution system' as "any system, works, plant, equipment or service for

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[163] Solas Presentation, *supra* note 159 at 7.

[164] Jessica Kennedy et al, "Alberta Electric System Operator announces new energy storage procurement opportunity" (October 22, 2020), online: Osler LLP <www.osler.com/en/resources/regulations/2020/alberta-electric-system-operator-announces-new-energy-storage-procurement-opportunity>.

[165] Waterton Battery Decision, *supra* note 20.

the delivery, distribution or furnishing of electric energy directly to the consumers, <u>but does not include a power plant</u> or transmission line" (emphasis added).

That said, we believe that an energy storage system could be either a power plant or a component of a distribution system, depending on the storage system's intended use. But uncertainty about energy storage's place in Alberta's regulatory framework may continue without guidance on why a storage system is a power plant in some circumstances and a wires system component in others.

3. THE AUC'S PUBLIC INTEREST MANDATE AND THE BROADER REGULATORY FRAMEWORK

The lack of an energy storage-specific statutory definition has forced the AUC to rely on "such existing definitions and enactments as might reasonably be interpreted to include or apply, however directly or indirectly, to energy storage resources".[166]

The AUC, however, has gone beyond existing statutory definitions when presented with energy storage applications. In doing so, the AUC has pointed to its mandate under section 17 of the *Alberta Utilities Commission Act* to consider whether the proposed power plant is in the public interest, having regard to the associated social, economic and environmental effects. While still subject to the downsides of extending the existing power plant definition to energy storage, we believe that the broader regulatory framework provides a principled basis for approving energy storage as components of power plants.

This approach is prominent in the AUC decisions on hybrid projects. Unlike stand-alone storage projects, hybrid projects co-locate energy storage with a traditional power plant. Examples of approved hybrid projects include TransAlta's WindCharger Project and the Drumheller Solar and Battery Storage Project.[167]

These hybrid project decisions follow a pattern. After noting that neither legislation nor AUC rules specifically address energy storage, the AUC states that it is considering the implications of the storage

[166] DSI Inquiry *supra* note 3 at para 231.
[167] Drumheller Solar and Battery Decision, *supra* note 141; Empress Solar Decision, *supra* note 132.

component in the context of the storage's use as part of the power plant as a whole, which the AUC must be satisfied is in the public interest. The public interest test–whether the application complies with existing regulatory standards, and the project's public benefits outweigh its negative impacts–is then stated, and the AUC considers whether the proposed plant meets existing regulatory standards.[168] Then, the AUC introduces its purposive approach to storage:

> Notwithstanding the lack of legislation or rules specific to the incorporation of battery storage into a power plant, the *Electric Utilities Act* and the *Hydro and Electric Energy Act* provide direction to the Commission on their respective purposes. Both acts promote the economic, orderly and efficient development and operation of generating units in Alberta.[169]

In our view, co-locating storage with variable or intermittent generating sources promotes the economic and efficient development of generating units in Alberta for the reasons discussed in section IV.A.2.[170]

B. OWNING ENERGY STORAGE

Who can own energy storage systems, and under what conditions, are long-standing questions that regulators worldwide continue to grapple with.[171] Here in Alberta, the AUC recently concluded:

> As existing legislation is silent on whether, how and, if so, to what extent the owners of energy storage resources should be regulated, the Commission, the [Market Surveillance Administrator] and the AESO – each within their respective jurisdictional domain – will be required to rely on the existing legislative framework to arrive at their own determinations unless this matter is expressly addressed by policy-makers.[172]

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[168] These standards are elaborated on in further detail in Section VII.C

[169] Empress Solar Decision, *supra* note 132 at para 42.

[170] While more analysis from the AUC on why approving energy storage as part of a power plant aligns with the purposes of the broader regulatory framework may be desirable, it appears that the AUC views the answer as obvious. On the WindCharger application, for example, the AUC's rationale on this issue was that "No party filed evidence on the record to suggest that approving the project would be inconsistent with the stated purposes of the *Hydro and Electric Energy Act* or the *Electric Utilities Act*". Notably, the only parties to the proceeding were the applicants, and no question about the purposes underpinning the regulatory framework was put to the applicants over three rounds of information requests (Windcharger Battery Decision *supra* note 143 at para 37).

[171] In 2019, European regulators allowed wires operators to own energy storage only under exceptional circumstances, while China forbid wires companies from including energy storage costs in their fees (IEA Report *supra* note 16). In Texas, transmission and distribution utilities may not own energy storage (Sam Porter, "Energy Storage in ERCOT" (October 7, 2019), online: Norton Rose Fulbright: <www.projectfinance.law/Npublications/2019/october/energy-storage-in-ercot/>. In Ontario, the *Ontario Energy Board Act, 1998,* SO 1998, c 15, Sched B was amended in 2009 to allow for regulated utility ownership in prescribed circumstances (*Green Energy and Green Economy Act, 2009*, SO 2009, c 12, Sched D, s 11)

[172] DSI Inquiry *supra* note 3 at para 449.

Relying on the existing legislative framework to arrive at a determination is no easy task. As the AUC recently concluded,[173] there are two main issues with the existing framework: (1) the *EUA* was designed for resources with different characteristics than energy storage, and (2) because energy storage can perform a range of services and deliver multiple value streams simultaneously, issues of double compensation and market distortion arise.

First, the *EUA* places generating units, distribution systems and transmission facilities into distinct watertight compartments. Under the *EUA*, both an "electric distribution system" and a "transmission facility" are defined as specifically excluding a generating unit.[174] Thus it appears that defining energy storage as a generation unit would preclude regulated utilities from owning energy storage as a regulated[175] component of either an electric distribution system or of the transmission system.

Second, other issues arise if energy storage is not defined as a generating unit. If defined as part of an electric distribution system, for example, an energy storage resource owned by a regulated utility would have the ability to participate in the energy and ancillary service markets while also benefiting from a regulated rate of return. As the AESO has pointed out,[176] this appears to conflict with one the *EUA*'s fundamental purposes—to provide for a fair, efficient and openly competitive electricity market in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages.[177]

Two ways to navigate these issues have emerged. One, the AESO's preferred approach, is for distribution- and transmission-facility owners to realize energy storage's potential reliability and infrastructure deferral benefits by procuring contractual services from non-regulated entities.[178] A second option is to focus on the specific application at question. For example, market distortion

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[173] *Ibid* at para 476.
[174] *EUA*, ss 1(1)(m) and 1(bbb).
[175] By "regulated", we mean subject to inclusion in the regulated utility's rate base and recoverable under the applicable regulated rate of return.
[176] DSI Inquiry, *supra* note 3 at paras 457-458.
[177] *EUA*, s 5(c).
[178] Waterton Battery Decision *supra* note 18 at para 12.

concerns seem to disappear if energy storage operates exclusively for reliability purposes and does not participate in the energy or ancillary services markets.[179]

A clear regulatory framework that identifies who can own energy storage, and what services different owners can provide, would offer the certainty needed to unlock energy storage's potential as an NWA. Rather than relying on regulatory bodies to determine these issues on an ad hoc basis, we believe that this issue requires public debate and a legislative response.

C. CONSTRUCTING AND OPERATING ENERGY STORAGE

As we've discussed, the AUC has characterized most of Alberta's permitted storage projects as power plants or components of them.[180] Applications to construct and operate power plants are brought under section 11 of the *HEEA*, which provides that no person may construct or operate a power plant without the approval of the AUC. When considering such an application, the AUC must have regard to the purposes of the *HEEA* and the *EUA*,[181] and the AUC must determine whether the power plant is in the public interest having regard to its social, economic and environmental effects.[182]

Procedurally, AUC Rule 007[183] governs power plant applications. The AUC recently amended Rule 007 to add storage-specific provisions, effective September 1, 2021. Under the amended Rule 007, battery storage is both integrated into the power plant provisions and the subject of a new section 10, specific to battery storage. For example, an applicant proposing to co-locate battery storage with a wind, solar or thermal facility must: (i) include, under the power plant provisions,[184] battery storage

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[179] An interesting wrinkle to this approach is the tension between two fundamental tenets underpinning the *EUA*: an openly competitive market, on the one hand, and an efficient market, on the other. Here, prioritizing minimizing market distortion may come at the price of efficiency, since, as parties in the DSI Inquiry pointed out, "this would be an inefficient allocation of resources, since a perfectly capable asset would be sitting idle due to regulation instead of being used to its full potential" (DSI Inquiry *supra* note 3 at paras 461 and 468, citing Exhibit 24116-X0518, "Distribution System Inquiry: AESO Responses to AUC November 29, 2019 Information Requests" (7 February 2020) at pdf p 42.

[180] As discussed above, there is significant uncertainty as to the operation of energy storage by a distribution system or transmission facility owner. If a energy storage system is proposed to operate as a transmission facility, the AESO would have to file a needs identification document with the AUC under Rule 007.

[181] *EUA*, s 5(c); *HEEA, supra* note 157, s 2. However, the AUC must not "have regard to whether the [proposed] generating unit is an economic source of electric energy in Alberta or to whether there is a need for the electric energy to be produced by such facility in meeting the requirements for electric energy in Alberta or outside Alberta." (*HEEA*, *ibid*, s 3).

[182] Alberta Utilities Commission Act, SA 2007, c A-37.2, s 17.

[183] Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines, AUC Rule 007 (5 March 2021) [**Rule 007**].

[184] *Ibid*, ss 4.2(WP1), 4.3(SP1) and 4.4(TP1).

in its calculation of the power plant's total capability, and (ii) submit the battery storage-specific information specified in section 10.

Aside from co-located storage, an applicant can apply under section 10 of Rule 007 to construct and operate a battery storage facility, whether as part of a power plant or otherwise. The applicant must file the information specified in section 10.1 in support of the application, and these information requirements are much like those required for other applications under Rule 007.[185]

That said, the AUC has placed great importance on emergency safety plans and control systems within battery storage units to limit the risk of fire and other safety hazards.[186] Further, one information requirement under Rule 007 specific to storage is the requirement to: "describe the recycling plan, based on current regulations, for the battery storage facility at project end of life."[187] Improper battery disposal can have serious environmental impacts, including toxic chemicals leaking into water supply, and even explosions.[188] The most common battery storage technologies contain toxic components that may leak into the environment when improperly disposed of, harming people and animals.[189] In at least two decisions, the AUC has imposed a condition of approval requiring that the applicant confirm that it selected a battery supplier that has a recycling or disposal program that follows environmental laws and best practices.[190] The AUC imposed this condition because it considered "that the improper disposal of battery cells could result in significant adverse environmental effects."[191]

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[185] Required information includes, an emergency response plan (s 10.1(BF16)), a project-specific environmental protection plan (s 10.1(BF22)), a noise impact assessment (s 10.1(BF24)), a decommissioning and reclamation plan (s 10.1(BF23)) and a participant involvement program (s 10.1(BF28)).
[186] Empress Solar Decision *supra* note 132 at para 44. The eReserve3 project before the AUC has received submissions from residents nearby concerned about the safety protocols in place for the proposed project.
[187] Rule 007, *supra* note 183, s 10.1(BF6).
[188] "Are Energy Storage Systems Facing a Battery Recycling and Disposal Crisis?" *Energy Storage News* (last visited 7 April 2021), online: Energy Storage World Forum <energystorageforum.com/news/energy-storage/energy-storage-systems-facing-battery-recycling-disposal-crisis>.
[189] "Are Energy Storage Systems Facing A Battery Recycling And Disposal Crisis?", online: Energy Storage Forum <https://www.energystorageforum.com>.
[190] *Ibid*; Windcharger Battery Decision *supra* note 143 at paras 13 and 41.
[191] Empress Solar Decision, *supra* note 132.

Lastly, applicants must identify any other approvals, reports and assessments required from other agencies. Some of the typically required approvals are detailed in Table 2.

TABLE 2:
OTHER APPROVALS REQUIRED FOR ENERGY STORAGE PROJECTS IN ALBERTA

Approval	Description	Source
Historical Resources Act clearance or permit	A clearance from Alberta Culture stating that there are no known historical resources is required. If there are historical resources, a permit (held by the archaeologist) is required. Must be applied for before submitting AUC application.	*Historical Resources Act*, RSA 2000, c H-9, ss 20 and 26
Wildlife Act compliance	Before applying to the AUC, the applicant must provide project details as they pertain to wildlife environmental matters to AEP for compliance with the wildlife policies. AEP assesses the completeness and sufficiency of information and, if necessary, identifies any other information that may be required.	*Wildlife Act,* RSA 2000, c W-10, ss 13 and 36
Federal *Species at Risk Act* compliance	Only required in the unlikely event that there is a species at risk present. Mitigation measures (such as conducting construction activities outside of nesting period) are required to prevent harm to endangered or threatened species.	*Species at Risk Act,* SC 2002, c 29, ss 32 and 33
AEP Conservation and Reclamation Directive for Renewable Energy Operations	A pre-disturbance site assessment must be completed as required by the C&R Directive.	*Conservation and Reclamation Directive for Renewable Energy Operations*
Municipal zoning and development	Depends on local bylaws.	

Self-supply, or behind-the-meter, energy storage systems are exempt from the requirement to file an application if: (a) the total capability of the system is less than 10 MW, (b) no person is directly and adversely affected, (c) Rule 012, which governs noise impact, is complied with, and (d) there is no adverse effect on the environment.[192]

[192] Rule 007, *supra* note 183, s 4.1.1.

D. CONNECTING ENERGY STORAGE TO THE POWER GRID

Storage owners who intend to use storage to draw or inject electricity from or into the AIES must apply to the AUC under section 18 of the *HEEA* and Rule 007 for a connection order. The connection threshold is 69 kV, below which a letter of non-objection from the local distribution company is required, and equal to or above which the AESO must assess the implications of the connection for the larger electrical system.[193] The AUC may also impose terms on any connection order granted.[194]

E. ENERGY AND ANCILLARY SERVICES MARKET PARTICIPATION

"Market participation" refers to energy storage's active, rather than passive, participation in the energy and ancillary services markets, including submitting priced offers and bids, restating those submissions when there is an acceptable operating reason to do so and receiving and complying with AESO dispatch instructions and directives.[195] Under the ISO Rules, assets greater than 5 MW in size have energy market participation obligations.[196]

The AESO has aptly framed the market participation issues:

> The current regulatory framework supports a traditional model, where electricity is produced by generators and transported through transmission and distribution systems to customers who purchase the electricity. Current ISO rules were not generally developed in contemplation of the integration of energy storage technologies to the interconnected electric system resulting in a lack of clarity in their application to energy storage. Specifically, ISO rules lack the clarity required for market qualification and participation, and to enable efficient, effective connection, monitoring, and control of energy storage facilities when connected.[197]

Two issues with the current ISO Rules are of note. The first is whether storage configured as a hybrid asset (i.e., energy storage co-located with variable renewable energy and offered into the market as a

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[193] Rule 007, *supra* note 183, s 5.1. Rule 007 also provides that the energy storage system owner proposing the interconnection must also provide "the legal subdivision of the interconnection point and an electric single-line diagram showing the interconnection point with the company" (s 5.1.1(IC1).

[194] *HEEA supra* note 157 at s 18(6).

[195] "Long-term Energy Storage Market Participation Draft Recommendation"(17 February, 2021) at 4, online (pdf): AESO <https://www.aeso.ca/assets/Uploads/Long-term-Energy-Storage-Market-Participation-Draft-Recommendation-FINAL-17FEB2021.pdf.> [**Long-term Storage Draft Recommendation**].

[196] *Ibid* at 6.

[197] "Letter of Notice for Development of Proposed Amendments to ISO rules to Enable Energy Storage" (17 February, 2021) at 1, online (pdf): Alberta Electric System Operator <www.aeso.ca/assets/Uploads/S1-LoN-ES-rules.pdf>.

single asset) should be allowed. Such configurations increase net demand volatility but make it easier for storage to participate in the energy and ancillary services market. The second is whether full-range participation ought to be required. Mandatory full-range participation (i.e., submission of market offers for both the charging and discharging capacity) prevents over-dispatch, although it removes operational flexibility and adds administrative burdens. Clarifying both questions will be important to enable storage's participation in Alberta's electricity markets.

1. HYBRID PARTICIPATION

Energy storage resources are, in part, defined by their ability to act as load when charging and supply when discharging. As the AUC concluded, "[b]ecause of this unique property, energy storage resources have a high potential to disrupt the current regulatory framework, which is centred around the concepts of load and supply."[198]

AESO asset types, source and sink assets, track these concepts of load and supply. As mentioned above, hybrid *sites* or *facilities* are traditional generating facilities co-located with energy storage. But a hybrid asset is distinct from a hybrid site or facility.[199] A hybrid asset also involves co-located VRE and energy storage, but an "asset" is an AESO construct used for financial settlement and market participation.[200] For market participation, the applicable ISO rules only apply to *assets* sized at 5 MW or greater. A hybrid facility can consist of either one hybrid or two independent energy market assets.[201]

The issue with hybrid asset configurations is that they can exacerbate net demand volatility issues, rather than alleviating them as we suggested above.[202] This is because, from the AESO's perspective, co-locating energy storage with VRE leads to greater variation in the possible output patterns from the site.[203] Even though the wind and sunshine are intermittent, the AESO can still use meteorological

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[198] DSI Inquiry, *supra* note 3 at para 240.
[199] Long-term Storage Draft Recommendation, *supra* note 195 at 8.
[200] Ibid.
[201] Ibid at 9.
[202] Ibid at 12.
[203] Ibid.

data to forecast minimum VRE production thresholds. But adding energy storage complicates this forecasting, as "the AESO cannot assume the asset will generate to its wind or solar potential as some or all of that energy could be redirected to charge the storage component".[204] If, on the other hand, the energy storage was an independent asset, the AESO would have full visibility of the flows in and out of the energy storage system.

That said, disallowing hybrid assets would limit active participation in the energy and ancillary services markets because, for example, a site with 3 MW of VRE and 3 MW of energy storage would not meet the 5 MW participation threshold without a hybrid configuration.[205]

The AESO has recommended that hybrid asset configurations be allowed under the ISO rules, with modification. The modification – a VRE block offer mechanism – is complex, and we await to see how the AESO will operationalize its recommendation in the ISO rules.

2. HALF-RANGE VS. FULL-RANGE PARTICIPATION

Half-range participation means only the discharge capability of an energy storage asset participates in the energy market, while full-range participation would require both the charge and discharge capability to participate.[206] Half-range participation can also increase net demand volatility: for example, assume an offer block of 20 MW of energy storage capacity is dispatched, but the energy storage resource was previously charging at 20 MW. This leads to over-dispatch, as the system needed 20 MW, but the shift from charging to discharging— from –20 MW to +20 MW—represents a total system delta of 40 MW. To rebalance this over-dispatch, the AESO must now dispatch the block off, and if the energy storage resumes charging because pool prices have decreased, there will be "saw tooth shaped volatility in real-time prices."[207]

[204] Ibid.
[205] "Long-term Energy Storage Market Participation Options Paper" (1 October, 2020) at 15, online (pdf): Alberta Electric System Operator <www.aeso.ca/assets/Uploads/Energy-Storage-Long-term-Market-Participation-Options-Paper-1OCT2020-FINAL.pdf>.
[206] Long-term Storage Draft Recommendation, *supra* note 195 at 19.
[207] Ibid.

This increased volatility can impact system reliability, as determining short-term adequacy requirements becomes harder and may cause the AESO to procure more regulating reserve to compensate for the 'charge to discharge' transition described above.[208] On the other hand, mandatory full-range participation removes operational flexibility and is administratively burdensome.[209]

The AESO has recommended optional full-range participation, using a linked-assets submission mechanism. The linked-assets mechanism assigns an energy storage resource both a source asset to offer discharge capability and a sink asset to offer demand response capability, and validates the source and sink offers as a pair. That is, "the participant cannot submit a combined bid and offer that results in infeasible or contradicting dispatches".[210] The AESO has suggested that more details are forthcoming,[211] and again we await to see how the AESO will operationalize its recommendation in the ISO rules.

F. TARIFF TREATMENT OF ENERGY STORAGE

Should energy storage have a specifically designed tariff structure? The AESO has been grappling with this question since 2012 when it launched a stakeholder engagement process.[212] This process led to a 2015 AESO recommendation paper that concluded that:

> the current legislative framework supports an energy storage facility being treated as alternating between supplying electricity to the transmission system (similar to a generator) and withdrawing electricity from the transmission system (similar to a load). An energy storage facility would therefore be charged for location-based cost of losses and comparable charges applicable to generators when [discharging] and would be charged for reasonable costs of the transmission system as applicable to load when [charging].[213]

In addition to this recommendation paper, the AESO also commissioned a University of Calgary cost causation study in advance of the 2018 ISO tariff proceeding. Based on these two studies, the AESO

208 Ibid.
209 Ibid at 23.
210 Ibid at 21.
211 February 24, 2021 Energy Storage Stakeholder Session Minutes" (24 February, 2021) at 6, online (pdf): Alberta Electric System Operator <https://www.aeso.ca/assets/Uploads/ES-Rule-Amendment-Stakeholder-Session-Minutes.pdf>.
212 Alberta Utilities Commission, AESO 2018 ISO Tariff Application, Exhibit 22942-X0163, "Amended 2018 ISO Tariff Application" at para 366.
213 Ibid at para 382.

sought approval for the application of Rate Demand Transmission Service to energy storage facilities when charging and Rate Supply Transmission Service when discharging, likening energy storage to other dual-use customers.[214]

The AUC approved this request. As no other party filed evidence in the 2018 ISO tariff proceeding on energy storage tariff matters, the AUC accordingly considered the AESO's evidence uncontested.[215] The AUC found that applying Rate DTS and Rate STS when energy storage is charging and discharging, respectively, is reasonable and "supported by current legislation, cost causation, the similarity to behaviour of some dual-use sites and the results of the University of Calgary's study."[216]

At present, the tariff treatment of energy storage is being considered in the AESO's bulk and regional tariff rate design stakeholder engagement sessions.[217] In this engagement, stakeholders have raised issues with the current tariff treatment, issues that are neither novel nor foreign to regulators and system operators around the world. For instance, one stakeholder has suggested that treating energy storage as a firm load customer is inefficient, as "[w]ith proper signals through a non-firm tariff, energy storage will locate where it is most economic [and] therefore will not cause any transmission costs increases".[218] Another has noted the "double double" problem relating to energy storage – namely, that "electrons stored and returned to the grid are already charged STS tariff rates to the original generator and DTS tariff rates to the ultimate end user. Therefore, charging tariff rates to the storage facility results in double charging for those electrons for both the grid injection and grid withdraw behaviour".[219]

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[214] *Re Electric System Operator* (September 22, 2019) at para 1202, 22942-D02-2019, online: AUC <https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/22942-D02-2019.pdf#search=22942>.
[215] Ibid at para 1209.
[216] Ibid at para 1210.
[217] "Bulk and Regional Tariff Design" (last visited 7 April 2021), online: Alberta Electric System Operator <www.aeso.ca/stakeholder-engagement/rules-standards-and-tariff/bulk-and-regional-tariff-design/>.
[218] "Stakeholder Comment Matrix – September 24, 2020: Bulk and Regional Tariff Design Session 2" AESO (September 24, 2020) online: Alberta Electric System Operator <https://www.aeso.ca/assets/Uploads/RMP-Energy-Storage-Stakeholder-Comments.pdf>.
[219] "Stakeholder Comment Matrix – December 10, 2020: Bulk and Regional Tariff Design Session 4" AESO (December 10, 2020) online: Alberta Electric System Operator < https://www.aeso.ca/assets/Uploads/CanREA-Stakeholder-Comment-Matrix-Session-4.pdf>.

The AESO, in turn, has noted (as suggested above) that as "Rate DTS and Rate STS have been found to appropriately attribute costs to dual-use sites, the similarity of the supply and withdrawal patterns of energy storage facilities suggests that those rates may be appropriate for energy storage facilities as well".[220] Further, the AESO has suggested that "many of the components of Rate DTS can be avoided or reduced through managed operation of an energy storage facility", such as, for instance, "[avoiding] bulk system charges by avoiding withdrawals from the transmission system during hours of coincident system peak".[221]

The tariff is currently due to be filed by October 15, 2021. As discussed above, the AESO is proposing changes to Rate DOS service aimed at increasing uptake by energy storage, as the AESO identified that energy storage could make use of available transmission capability that it otherwise could not, providing a benefit to other ratepayers while not driving the construction of additional transmission facilities.[222]

VIII. CONCLUSION

Energy storage technology is commercially viable and is being deployed across Alberta, with more projects on the way. In the recent past, costs were the largest hurdle to widespread energy storage deployment. But this has changed dramatically in the last few years with plummeting battery prices, as well as plummeting prices for wind and solar projects, projects which can benefit from the addition of energy storage.

Now, the remaining hurdles are Alberta's applicable legislation and regulations, in that they lack clarity on their application to energy storage. Alberta's traditional model of electricity regulation, based on generators supplying electricity to load customers for consumption, does not contemplate technologies with the unique attributes of energy storage, which can look like load when charging and

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[220] *Alberta Electric System Operator 2018 ISO Tariff Application*, AESO (September 14, 2017) at para 374, online: https://www.aeso.ca/assets/Uploads/AESO-2018-ISO-Tariff-Application.pdf.
[221] *Ibid* at para 391.
[222] Bulk and Regional Tariff Design Stakeholder Engagement Session 5B (Demand and Opportunity Service)", AESO (May 20, 2021) at 42, online: <Session-5B-DOS-Presentation.pdf (aeso.ca)>.

like generation when discharging, and indeed incurs both sets of costs, but yet has distinct behaviours and benefits.

In this regard, we look forward to the AESO's Energy Storage Roadmap integration activities both over this year and the long-term. And we welcome the AUC's amendments to Rule 007, as they provide certainty to proponents on how the AUC will consider applications to construct and operate energy storage systems.

To conclude, all stakeholders would benefit from increased legislative certainty and the direct contemplation of the benefits and challenges associated with energy storage.