Canadian Renewable Energy Association | Association canadienne de l'énergie renouvelable

September 3, 2024

Alberta Utilities Commission
Sent via: engage@auc.ab.ca

Dear Laura Johnson,

On behalf of our members, the Canadian Renewable Energy Association (CanREA) wishes to provide feedback to the Alberta Utilities Commission (AUC) on Bulletin 2024-08 and the associated draft version of AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines.*

We commend the AUC and its staff for the time and diligence with which they have approached this process. Throughout the consultation process, staff have made an obvious and concerted effort to engage with the renewable energy industry. These efforts are much appreciated.

In the spirit of continuing engagement, the attached Appendix ("Comments on Revised Draft Version of Rule 007, dated September 3, 2024") outlines further commentary from our members on various issues, including:

- Approval Renewal Requirements
- Approval Transfers
- Agricultural Land
- Land Suitability Rating System (LSRS)
- Setbacks from Residents and Other Important Infrastructure
- Reclamation Security
- Energy Storage Facilities

Once again, thank you for the opportunity to provide comments on the ongoing development of the updated AUC Rule 007. We look forward to further conversations and consultation prior to finalization of this rule. If you have any questions or comments, please reach out at rrajagopalan@renewablesassociation.ca or (780) 405 6941.

Regards,

Radha Rajagopalan
Director, Alberta

Appendix: Comments on Revised Draft Version of Rule 007, dated September 3, 2024

The comments included expand on the topics included in CanREA's oral position stated in consultations held between May-June 2024.

Approval Renewal Requirements (including Time Limits)

CanREA understands the AUC is seeking to balance appropriate regulatory oversight to deter irresponsible development while providing the necessary flexibility to support reasonable and standard development. CanREA believes a ten-year development timeline from the start of construction is appropriate for the vast majority of generation projects in Alberta, provided that approvals are kept up to date.

CanREA considers 10 years a reasonable time period for construction because delays due to outside factors may be unavoidable (ie. due to impacts from government policy changes, and economic circumstances). Should the AUC prefer to provide an interim time extension for impacts expected pending final market restructuring rules, automatic renewal of permits expiring before December 31, 2026 should be extended for a two-year period to allow ample time for construction. Setting a maximum length of time, provided that time is no less than 10 years, will provide better predictability and reduce risks for projects rather than providing a set number of time extension opportunities. Reducing the regulatory process would allow the Commission to spend more time on more substantive matters. Time extensions should be granted without the need for providing detailed reasoning, beyond the ability to demonstrate that surveys and other items related to the AEPA referral report have been kept up to date with respect to the AEPA requirements. For existing projects a ten year extension should be applied to any projects with up to date approvals.

In addition, the option to remove the opportunity for extension after "construction start" creates barriers, especially given the impacts that changes to government, policy, and other economic circumstances can induce – delays may be uncontrollable. As an example, a mechanism for an automatic and limited extension in the construction period for merchant projects impacted by REM that have reached certain specified milestones would be helpful. If the opportunity for timeline extensions are eliminated, a significant approval period is required.

Approval Transfers

A transfer of approval should be subject to the regulatory regime in place at the time of the project application. Requiring transfer approvals to be subject to the regulatory regime in place ***at the time of the transfer*** will lead to increased uncertainty and significant regulatory risk which will inhibit further investment into the province. When transfers are approved, the new owners of any given project are expected to take on all previous approval conditions. New requirements will lead to further complications.

Agricultural Land

Because the AUC recognizes that power plant development has not historically been a primary driver of agricultural land loss and that market forces have resulted in trends that site renewable development on non-prime land, there is no need to add additional, more stringent or disruptive requirements.

Pre-disturbance site assessments

CanREA members are supportive of a requirement to provide some details earlier in the process, such as what is already required under the interim Rule 007 requirements, as this will likely mitigate regulatory risk earlier in the process. The current interim information requirements, which include reference to the Agricultural Regions of Alberta Soil Inventory Database (AGRASID) and a requirement for reporting on soils by a professional agrologist, are supported by CanREA members. We would recommend that these requirements be included in an updated Rule 007.

A full pre-disturbance site assessment (PDSA) would be exorbitantly expensive and unnecessarily burdensome prior to the application stage. A PDSA completed closer to start of construction is more cost-effective and will better inform soil handling. Other industrial developments within the province (regulated under EPEA) require PDSA data to be collected and presented to the regulatory agency for review six months prior to any land disturbance taking place. Renewable power plant developments should follow similar conditions for the reporting requirements for PDSA and Conservation & Reclamation (C&R) Plan information. This change could serve to be an enhancement to current approaches. The existing method of preparing a C&R Plan for power plant developments prior to collecting PDSA data limits the ability of the C&R Plan to fully capture the requirements to be adhered to during construction, operation, and site reclamation and closure.

CanREA notes that preliminary site studies do not necessarily result in the best environmental or economic outcomes. Soil field verification is very costly and time intensive, and should not be required until pre-construction, when more project construction details are better understood, as outlined in the *Conservation and Reclamation Requirements.* Pre-approval, applicants should be required to provide desktop analysis based on existing data sources, such as the Agricultural Regions of Alberta Soil Inventory Database (AGRISID), and elaborate on all earthworks planned for the project for review by the AUC. Details that impact a PDSA, but that are finalized only after project approval include:

- Placement of infrastructure and total disturbance footprint
- Final equipment selection and procurement, including type and size of piles
- EPC construction schedule and sequencing of activities
- Positioning of access routes and laydown areas
- Geotechnical design
- Environment constraints such as weed and vegetation present in the prior growing seasons

Finalization of these project details are important considerations in the site-specific planning and successful outcomes of the PDSA. An alternative to early field verification and the PDSA could be the implementation of Construction Codes of Practice (CoP). The CoP could detail required topsoil and subsoil salvage and separation (e.g., salvage all topsoil and separate from subsoils, deploy 2 lift procedure for subsoils). A CoP could be more useful for landowners and operators, while simultaneously meeting the intent of soil conservation and maintaining equivalent land capability. For example, AEPA, AER and DFO have CoPs for certain routine activities and these may serve as a model for soil management during construction. If an operator meets the CoP requirements, then no other work is needed. Regulators could have the right to request proof of compliance with the CoP.

Timing should align as near to construction as possible, as this is the point where operators will have nearly finalized designs and have contractors involved who will be doing the actual earthworks. It will also capture pre-disturbance conditions nearer to actual disturbance, avoiding replication and assessment of lands that will ultimately not be disturbed. Verification would entail soil sampling, but landowner input should also be given weight in this process. Landowners know best how good the soil is and what can be grown on it. The existing Conservation and Reclamation Directive for operators already lays out soil sampling requirements (which is verification). If soil verification is going to be required, we would suggest that early-stage effort be minimal. This could involve test pits, limited to one per section of land under lease. For PDSAs, the Directive is already too onerous. The Directive requires extensive sampling of soils along collection lines and roads (can be around a 100 km for a typical wind facility). In fact, in recognition of the excessive requirements, AEPA has granted operators soil survey flexibility as part of the PDSA. For example, a PDSA completed for a 35 turbine wind facility with 15 km of access roads, 60 km of collector lines, 1 substation, 1 O&M and 1 temporary laydown site would require a minimum of 750 sampling locations. This assumes the PDSA was completed once and followed the recommendations in the Conservation and Reclamation Directive for operators. More detailed sampling only seems relevant when sampling is necessary to confirm the land is not Class I or II. It should not be required to verify all land classes.

CanREA recommends that a good C&R plan with some on-site monitoring is a cost effective way to manage soils. Good operators do a good job when they are required to do so under contract. Having qualified Environmental Monitors around increases the ability to hold contractors to account. Depending on the size of the project, the size of the soil disturbance and the intensity of soil sampling requirements, these costs will vary. However, we have heard from members that PDSA with sampling to confirm land class would cost anywhere from $150 k to $250 k.

Success and Agrovoltaics

CanREA is seeking more clarity from the AUC on their definition of success and the proposed approach to agrivoltaics.

Best Use of Land and Defining Success

CanREA supports the development of a working definition of best-use in collaboration with host landowners and host communities. There is a distinction to be made between “best use of agricultural land” and “best agricultural use of land”. It is key to remember that the landowner / farmer is key to successful implementation of agrivoltaic solutions. Any agrivoltaic solutions should move forward only with the support of the landowner – and they should have some say in whether an agrivoltaic solution must be implemented.

Use of a single aggregated, province-wide evaluation standard to determine agricultural land quality, absent any local assessment, is unlikely to be fully reflective of the agricultural value at any one location. Assessment of agricultural land values will be influenced by the type and intensity of the land use and the professional judgement of the assessor. Value determinations will be dependent on many factors that may change with time such as the type of crop, soil amendments, harvest practices, or climate factors, such as the drought versus wet cycle. Interactions between these various factors will influence the assessed agricultural land value at a given point in time.

As long as the land is not sterilized by the project, meaning that it supports some kind of production or is planted with solar-facility appropriate vegetation (e.g., to support pollinating insects or to conserve soils), it should be considered a success. This distinction is very important. If the test is “best agricultural use of land”, solar and its collocated ag activities (which will likely be grazing and haying), will lose to cereal crop on a revenue per acre to the landowner basis almost every single time. It’s a predetermined outcome. If the test is “best use of agricultural land”, a solar production facility co-located with haying or grazing will win 100% of the time in terms of revenue to the landowner on a per acre basis (due to solar land rental rates usually being significantly more than what they can earn with even the best cereal crop—and its certain). Income from agrovoltaics is a stable long-term income versus having only crops on the land which are susceptible to droughts and floods.

Agrivoltaics and Productivity

Production targets are not realistic. Renewable energy production, wind, solar and energy storage projects, are already co-located with agricultural activities, because those lands generally have fewer environmental constraints. According to DNV, the opportunities for solar and agriculture co-location include sheep grazing, beekeeping, agrivoltaics and “crop production that incorporates growing opportunities between the rows and under panels”. Agricultural value is considered in collaboration with participating landowners. We’d also note that 4% of projects are located on either Class I or Class

II agricultural lands in Alberta. This demonstrates the responsiveness of CanREA members in responding to productive agricultural value.

CanREA strongly recommends that the AUC does not introduce a requirement related to productive agricultural land. This requirement will introduce a requirement for largely subjective expert reports that are not easily or predictably adjudicated. It will be a new issue for intervenors to grab hold of and litigate making hearings even more frequent, prolonged, and costly.

CanREA supports inclusion of details around farmer activities in combination with renewables at the time of application, as it demonstrates productive engagement and productive relations with landowners. However, the AUC should be aware that this requirement may put unnecessary pressure on participating landowners, who may not have access to historical data or maps going back far in time.

Some questions to consider around defining land:

- How will "productive agricultural land" be defined? Is it an average output over the last X years?
- Does insurance count in the revenue calculation? Is productivity defined as bushels per acre or in terms of revenue per acre for the landowner?
- What if some years are grazed and other years are cereal crops? What is the price per head of sheep in a given year?
- What is considered a comparable "benefit"?

CanREA believes there are key constraints involved in co-locating agricultural activities with energy production. The cost of agrivoltaics to establish and/or maintain can be prohibitive for farmers. In areas with lots of existing weeds, aggressive weeds can out compete the planted species, requiring herbicide and/or re-seeding over multiple years. In drier climates re-establishing vegetation can take multiple years, sometimes also involving multiple re-seeding events. There is a lack of clarity on the definition of 'success'. There is a risk of reduced electricity production. A landowners choice on how to use their land is removed. Farmers choose agrivoltaics based on their own economic factors, rotations, cost of inputs, drought or wet conditions, market factors (such as price). Renewables developers are in the same position and can't put strict requirements on the agrivoltaics plan. Flexibility is imperative because sometimes agrivoltaics will not be feasible environmentally, socially and/or economically. Based on members' US experience, the success and applicability of agrivoltaics depends on previous land use (pre-solar uses), soils, general climate conditions in the region and participating landowner support. Planting pollinator crops (mix of native and non-native) may happen quickly or may take a couple of years to fully establish (factoring in site preparation and achieving >70 % land cover).

Irrigated Land

Renewable energy projects are generally not located on irrigated lands. CanREA acknowledges that irrigated land could be considered to be more valuable than unirrigated land as the infrastructure (canals, pipes, etc.) have already been installed by the irrigation district and sprinklers purchased by landowners. However, there is also a lot of land in southern Alberta that is semi-arid, so one could certainly argue that cropping these lands is not the "best" use of these lands given that in most years precipitation will be low making the growing crops inherently risky.

Land Suitability Rating System (LSRS)

LSRS is readily available online. The assessment methodology is stated clearly although it is probably not understandable to most people that aren't agrologists or in farming. Also, it has some limitations including:

- desktop mapped
- coarse scale
- on-the-ground conditions could be much different than mapped data (ie there is a variability in soil types across the polygons, and potentially through the depth of the topsoil and subsoil across any parcel of land)
- not necessarily relevant to achieving soil conservation during construction of renewable (or other types of commercial/industrial) facilities.
- The mapping in the LSRS does not reflect past and current land practices that affect topsoil quantity and quality. Soil verification is needed to properly assess the land. In many cases, AGRASID shows overlapping polygons of classes in the same place further indicating the need for soil verification to properly assess the land.

It is possible to contest the LSRS anywhere in southern Alberta because the system uses coarsely measured soil map units in a semi-arid environment that is used intensively. As a general land classifications tool, they can help with planning, but these are desktop mapped polygons that have not been field verified (in most instances) and as such do not necessarily represent actual conditions. The mapped units could be substantially different from the reality on the ground. For example, a 640-acre section of land may be mapped as Class I LSRS, but the soil verification may review a different LSRS rating (e.g., 200 acres Class I and 440 acres Class III).

Due to the limitations outlined, a Land Suitability Rating System (LSRS) may not be an appropriate tool to rely on solely for the purpose of determining Agricultural Land verification for Class I and II versus other land Classes.

Setbacks from Residents and Other Important Infrastructure

Setbacks, based on project impacts, have already been implemented in Rule 012: Noise Control and no further criteria are necessary. CanREA requests that the AUC create a gap analysis to support any additional setbacks outside of Rule 012 so that stakeholders can better understand the need for these changes. Setbacks related to "other important infrastructure" (including roads, highways and other pipeline/utility infrastructure) are covered by existing agencies/regulations/standards.

Having to locate far away from places that need the power (residences, hospitals, schools, railways, airports, industrial facilities) means that more transmission infrastructure would be needed to get power to those places. Compliance with Rule 012 is a reasonable factor to stand as a de facto setback approach. The other factors such as shadow flicker and glare, are already sufficiently reflected in the Rule 007 process.

Reclamation Security

It bears repeating that a jurisdictional scan by DNV has resulted in the discovery of no record of abandoned wind or solar facilities in Canada or the US. Still, CanREA can support the new information requirements on reclamation security. We recommend that these information requirements be included in the updated *Rule 007*. We support the use of third party estimates of costs in order to determine the scale of reclamation security required. Any decision to implement a standard "per-MW cost" or similar across-sector cost estimate standard is unlikely to reflect the range of reclamation costs across all projects.

Preliminary financial security commitments should be filed as part of the AUC *Rule 007* application, including confirmation of a security provision and a detailed plan for getting an independent reclamation cost assessment report and timeline for providing the security to the landowner. The amount of security should be determined based on a report provided by a third-party or engineer's assessment. The cost estimate should describe the methodology and assumptions used to calculate the estimated cost of decommissioning and reclaiming the site at the project's end of life, including the cost impacts of any salvage value that could be expected. According to DNV, these estimates would typically include overhead and soft costs, disassembly of the project components, transportation of the components to their end-of-life destination, disposal/recycling/salvage requirements, and restoration of land. It is critical for these assessments to occur on a project-by-project basis, as a literature review by DNV has determined that industry-wide estimates of decommissioning costs are often inconsistent.[1] Due to this inconsistency, any solar- or wind-industry-wide determination of costs for reclamation security in Alberta may result in insufficient funds being put aside for landowners. A project-by-project, third-party assessment will ensure that all participating landowners are properly covered.

A final cost assessment and commitment to security should be filed with the AUC prior to project construction. This phased approach is recommended due to interactions between landowner engagement, project development and permitting timelines. Often, landowner agreements are signed before all project design details are finalized for application. Furthermore, these details may evolve based on the AUC process, including project size and micro-siting decisions.

We also support the flexibility available to choose the appropriate form of security, and recommend that this flexibility be maintained in Rule 007. We further recommend that this explanation also support flexibility in the timelines in which security is provided to landowners. According to DNV's expert report, even in jurisdictions where financial security is required, the commitment may be required at the final permitting phase, but the security itself can be provided at a later date. This approach is "understood as a compromise that allows for the project's initial capital expenditures to be partially amortized before the additional financial burden of freezing funds for decommissioning comes into effect."[2]

Between the time of the application and the time of the approval, project details are evolving in such a way that the cost of reclamation may not be sufficiently understood to make a final commitment. However, these details will be known prior to construction, making that time more appropriate for cost estimates and demonstration of the security commitment.

Energy Storage Facilities

Generally the current approach and interim requirements are appropriate for energy storage. With respect to air quality dispersion modelling, it would be helpful to define what specifically should be modelled.

Battery Energy Storage Systems (BESS) are inherently very safe relative to other industrial facilities.[3] They also have many benefits including that they minimize greenhouse gas emissions and reduce

[1] DNV. Renewable Energy Project End of Life Considerations and Decommissioning/ Reclamation Requirements. Pg.8.

[2] DNV. Renewable Energy Project End of Life Considerations and Decommissioning/ Reclamation Requirements. Pg.9.

[3] CanREA and Energy Storage Canada. Solar Electiricty and Battery Storage Systems Safety Handbook for Firefighters. Pg. 8.

reliance on less environmentally friendly power sources. Although BESS fires have been well-publicized, there is minimal risk compared to the number of hours of BESS operations. The risk of a fire is remote because the battery chemistry is such that it would be highly unlikely for it to get hot enough to cause a large scale fire across all modules. Fires tend to be contained in a single module and the chemistry often prevents the fire from escaping. In order for the fire to spread across the battery storage facility, the fire suppression mechanisms would need to fail such that the fire escaped the container (highly unlikely). In addition, the wind would need to be blowing in the exact direction of a receptor (human) at the time of the fire and the concentrations of chemicals in the air should not have dissipated by the time the fire reached the receptor (also unlikely). BESS systems are composed of parts that can have varying degrees of quality and some of the lower quality parts may be more prone to fire. However, manufacturers have an interest in ensuring the long term viability of their products and thus have maintenance and other specifications to ensure that if original equipment manufacture (OEM) requirements are followed, fires are minimized.

Guidance for Emergency Response Plans (ERPs) can be found in National Fire Protection Association Standard 855: Standard for the Installation of Stationary Energy Storage Systems (NFPA 855)[4], section 4.3 and Annex G. It is a current best practice that is incorporated in BESS systems.

In terms of setbacks, current Rule 007 requirements are sufficient since the size of the facility is immaterial to potential impacts on nearby infrastructure. IAs long as operators are following OEM guidelines, which set out requirements to ensure the safe operation of BESS modules and the system as a whole, then the risk of accidents is low. These requirements are also required by insurance providers to properly insure the facility. The requirements include guidelines on the distance between modules/units.

The development of a checklist for applications would be helpful for applicants if it provides sufficient flexibility to apply to a variety of different project sizes and project footprints. Some sites may require more site specific assessments and in those cases, the AUC can request additional information.

A checklist would help for items such as:

- Air dispersion modeling
- ERP (how to handle a fire situation)
- Key OEM certificates (ie. NFPA 855 (latest edition) and UL9540A (Large Scale Fire Testing). These should be tested at the cell, module and full unit level.

Energy Storage facilities have operational (OEM) parameters for BESS, insurance companies have requirements in place for BESS and these two combined are sufficiently stringent that it is not necessary for the AUC to layer on more rules.

[4] NFPA 855. Standard for the Installation of Stationary Energy Storage Systems.