June 15, 2026

Peter Kernan
Senior Utility Analyst, Resources and Programs
Oregon Public Utility Commission
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

RE: Staff's May 22, 2026 Update and Request for Comment (Docket No. AR 681)

Dear Mr. Kernan,

The undersigned organizations respectfully submit the enclosed joint responses to Staff's May 22, 2026 Update and Request for Comment, addressing all five priority questions and the open questions in each workstream. These responses are continuous with the coalition's March 20, 2026 Workstream 1 letter, the April 24, 2026 islanding and data sharing comments, and the April 2026 zone designation process materials. The enclosed answers are deliberately brief; the coalition can provide the underlying analysis, models, and precedent research on any point at the workstream meetings or on request.

The undersigned authorize the Commission to post this letter and the enclosed responses publicly to the AR 681 docket. Questions regarding this submission may be directed to Kevin Wright, ProtoGen, Inc., Kevin@ProtoGen.com, 1-888-365-4743. Thank you for the opportunity to continue contributing to the full implementation of HB 2065 and HB 2066.

Sincerely,

Alex Clingman, Clean Energy Program Manager, Sustainable Northwest joined by:

Cascadia Renewables
Clean Coalition
Green Energy Institute
Microgrid Resources Coalition
Oregon Solar+Storage Industries Association
PAE
ProtoGen, Inc
Sierra Club
Sulis Energy

Priority Question 1: Track B structure

Should Track B be implemented as an overlay to Division 82, as a new division, or through another structure?

A new division of OAR chapter 860 for community microgrid systems is needed. It should be joined to Division 82 by narrow conforming amendments and an enumerated incorporation by reference of Division 82's generally applicable rules (waiver, insurance, recordkeeping, arbitration, enforcement). Track A remains in Division 82 with targeted amendments. The distinction is based in HB 2065 and HB 2066's contemplation of different interconnection and operational structures based on the microgrid framework. A Track A project is a microgrid under HB 2065 Section 2(1)(b) and fits Division 82's tiered, single PCC & POI facility architecture. Track B is a community microgrid under Section 2(1)(a), reviewed as one system through the microgrid system interconnection request (MSIR): one application filed by the local government or its designated sponsor, one queue position, one study sequence covering grid connected and islanded modes, with a participant schedule giving the utility complete per PCC data while eliminating per PCC applications and studies. The coalition's April 24 comments described the MSIR study flow as an overlay on the Tier 4 sequence; working through that drafting is what demonstrated the structural problem. Division 82's definitions, screens, 10 MW nameplate cap, anti-islanding orientation, and bilateral agreement structure are single facility throughout, and every overlay gap defaults back to that structure. The new division therefore retains the Tier 4 stage interconnection process nomenclature for continuity while replacing the architecture. Cluster studies may be required based on new generation being proposed, while supporting serial studies for flexible interconnections as an intermediate step to allow the microgrid to get up and running. Attachment A outlines the proposed division; Attachment B gives a rule by rule disposition of Division 82. The structure follows Hawaii's implementation of Act 200 (standalone Rule 30 plus targeted interconnection rule changes, Docket No. 2018-0163) and avoids California's per resource approach (Decision 24-11-036), which parties criticized as unworkable for community scale projects.

Priority Question 2: minimum rule level requirements

What minimum rule-level requirements should apply to microgrids that include utility-owned infrastructure within the microgrid boundary?

Eight requirements belong in rule.

1. A microgrid controller performing the core functions of IEEE 2030.7, with conformance demonstrated per IEEE 2030.8, citing each standard with the formulation “or its successor.”
2. Intentional islanding per IEEE 1547-2018 Clause 8.2, with unintentional islanding detection and trip per Clause 8.1 in grid connected mode, distinguished by controller signal.
3. Execute a community microgrid coordinated operations agreement on a Commission approved template with the government, microgrid operator (if applicable) and utility before energization.
4. Clearly define the microgrid operator role: an entity identified as having responsibility for overseeing the coordination of the system's loads and resources and representing

participants in interactions with the utility (HB 2066 Section 2(1)(f)), whose controller exchanges signals with but does not operate utility distribution equipment, and never assumes the utility's control of its own infrastructure (Section 2(3)(q)).

5. Implement a system level study of both grid connected and islanded modes, including impacts on customers outside the boundary. The study can be completed by a customer selected third-party Oregon PE, the utility, or its third party engineer.
6. Energy production and consumption revenue metering at each PCC.
7. Designation of the POI boundary switching device that controls entry into and exit from islanded operation, operated by its owner: a utility owned device is operated by the utility upon controller signal under the coordinated operations agreement.
8. Define and allow for modification of standards and ongoing compliance obligations. Standardized microgrid topologies, major equipment types, equipment specific settings, telemetry, and test procedures belong in utility handbooks, not rule (see Workstream 3).

Priority Question 3: zone initiation and Staff support

What should the Commission require for communities to initiate the zone approval process, and how should Staff support local governments?

Initiation should be low friction: a community's stated interest is enough to begin, and a community authorization letter signed by the mayor, county administrator, tribal chair, or equivalent authority establishes standing for data access under the rules recommended in Priority Question 4. No ordinance or resolution should be required to access data. The municipal resolution conditionally designating the zone comes after engineering and rate impact analysis are complete, so the community commits with real numbers. The resolution passage triggers the Commission application under HB 2066 Section 7, supported by the resolution, the PE stamped and utility approved interconnection study, a rate impact analysis including low-income analysis, and community engagement documentation, reviewed against a rubric published before any community enters the process (Attachment A). The proposed rubric pairs pass or fail documentation gates, a valid municipal resolution, complete approved studies, interconnection and upgrade costs with operation and maintenance determined, a low income impact analysis, and documented community engagement, with reasonableness factors: a design likely to achieve the stated resilience goals, rate impacts proportional to the quantified benefit, proper consideration of low income and subsidized ratepayers, and adequate engagement.

Staff support should include five elements:

1. A Commission developed template authorization letter
2. A template municipal resolution covering boundary description, resilience goals, rate impact acknowledgment, authorization to engage the Commission process, and conditionality language
3. A plain language step by step guide covering the full sequence with statutory citations and typical timelines including the approval rubric
4. A Commission assigned community liaison for each community pursuing designation, mirroring the utility liaison HB 2065 Section 2(6)(d) already requires.

5. The Commission should also set target review timelines with accountability if reviews exceed them, because community momentum is fragile.

Priority Question 4: tiered data sharing

What tiered data-sharing requirements should be adopted under HB 2065?

Adopt the three tier framework detailed in the coalition's April 24, 2026 comments and the Oregon Utility Data Request workbook.

1. Tier 1 is public screening data: an interactive hosting capacity map plus downloadable CSV and XLSX exports, refreshed quarterly, no registration, feeder level aggregates only, no customer identifiable information.
2. Tier 2 is qualified nonpublic data for design and zone designation work: engineering grade feeder, protection, transformer specification, voltage control, and time series load data, delivered machine readable within the HB 2065 Section 2(6) twenty one day clock under a standardized NDA, including aggregated participant counts by rate schedule inside the proposed zone, without customer identifiers, sufficient for rate recovery allocation design; the utility applies customer specific elements, including the income qualified low-income exclusion, within its own billing systems without disclosing enrollee identity.
3. Tier 3 is study execution data for the retained professional engineer during an active MSIR study phase: full network model in CIM or utility native format, protection settings and time current curves, fault current at the POI, handled consistent with CEII treatment under 18 C.F.R. 388.113. Because HB 2065 Section 2(6) attaches to the retained third party consultant, the Commission should adopt the pre application tiers as rules under its HB 2066 Sections 2(2) and 2(3)(f) authority, with Section 2(6) supplying the statutory floor once the consultant pathway is engaged.
4. Three general rules:
    a. A standardized Commission approved NDA drafted within ninety days of a final order
    b. A due process path under which a utility denying a request must state its basis in writing within the same twenty one days and propose an alternative means of answering the technical question
    c. Coordination with the third party study criteria utilities must publish under Order 26-108 in AR 683, criteria that serve the same third party study right HB 2065 Sections 2(2)(b) and 2(5) established here, so utilities do not maintain two divergent frameworks.

Priority Question 5: local cost recovery criteria

What criteria should the PUC adopt for local cost recovery for community microgrids?

Local cost recovery is limited to Track B community microgrids. The recovering class is the customers within the locally designated and Commission approved microgrid zone, plus

customers immediately outside the zone who opt in. The opt-in exists because a zone is bound by the establishing local government's jurisdictional limit, and that boundary does not always align with the utility infrastructure serving the community microgrid. Where the infrastructure reaches an adjacent customer but the jurisdictional line does not, the opt-in lets that customer join the recovering class.

For customers inside the zone there is no individual, PUC-defined opt-out. The decision to establish the zone is a local one, and the question of whether any resident may decline participation is resolved through local community planning and engagement, with protections built in, rather than at the Commission. This mirrors ratemaking generally. Approved cost recovery does not require unanimous participant consent, because an individual economic opt-out would shift the recovering burden onto the remaining participants while the opting-out customer continued to benefit from the maintained system. A customer inside the zone could potentially opt out electrically by declining physical connection, but not economically, and that edge case is best handled within the local planning and design cycle rather than by the Commission. What the framework requires instead is a clear need, thoughtful consideration, and protection for customers who need assistance, supported by the layered protections described below.

Recoverable costs are limited to shared or common microgrid infrastructure and recurring operation and maintenance, including the microgrid operator. Privately owned equipment is never recovered through rates. The base DER investment is recovered through market or tariff revenue streams and is not a local recovery subject, so only the incremental shared resilience premium is recovered under HB 2066 Section 2(3)(L), allocated by a standardized, formulaic methodology established once in this docket so that no community needs a separate rate case.

The value of resilience, in terms of the value a microgrid can provide to the grid, is best realized with nodal, time interval, and event based metering. Rate design should be workshopped to distinguish four customer groups: customers directly connected to the microgrid circuit, customers that benefit from services the microgrid enables, customers with generation resources that contribute to the microgrid, and income-qualified customers receiving low-income discounts. Income-qualified customers are excluded from local recovery across all classes, with the excluded share absorbed within the project's participant classes and never reallocated to non-participants.

Approval applies the published rubric's reasonableness factors, with proportionality validated by the Interruption Cost Estimate (ICE) Calculator and a benefit cost analysis incorporating the value of resilience and the value of lost load. Both the ICE and BCA methodologies require further development, because neither currently accounts for the value of lost load, which HB 2066 requires. The utility study report must break out islanding attributable cost from baseline interconnection cost, with an attribution schedule for preexisting DERs so the allocation is auditable, and a true up applies where actual impacts exceed approved projections. Establishment of a zone remains subject to the Commission's discretionary authority under the two-part zone approval rubric.

Workstream 1: Interconnection

Should the Track A / Track B framework be implemented within Division 82?

Partly. Track A yes, through targeted Division 82 amendments. Track B no, for the structural reasons in Priority Question 1. Three Division 82 updates should accompany the framework: add the microgrid operator definition and role (HB 2066 Sections 2(1)(f) and 2(3)(q)) to Division 82, because operators can serve Track A projects as well; align the Division 82 POI and PCC definitions with current IEEE usage. Division 82 collapses the two into a single term, which is workable for single facilities but loses the distinctions IEEE 1547-2018 draws between the point of common coupling and the point of DER connection, and IEEE 2030.7 draws for the POI as the controlled grid interface, distinctions a multi PCC system requires; and raise the 10 MW nameplate limit to 20 MW through coordination with UM 2111, because the 10 MW figure traces to the 10 MVA scope limit of IEEE 1547-2003, which IEEE 1547-2018 removed, and the federal small generating facility threshold is 20 MW.

What should trigger additional islanding or aggregate review for Track A projects?

Track A projects should be addressed as Division 82 addresses them today, with no additional study requirement. Whether a project is Track A or Track B is determined at Feasibility by the island electrical boundary: utility infrastructure inside the boundary makes it Track B. Beyond that classification, two events warrant further review, and both are already covered by Division 82's framework: an existing Track A project being considered for inclusion in a proposed Track B system, which is evaluated once in the MSIR system impact study while the project retains its agreement and receives an operating mode amendment, and a significant system configuration change after interconnection approval, which requires a new study under the material modification standard.

How should microgrids over 10 MW be treated?

Under the MSIR, the Division 82 cap does not apply; the HB 2065 Section 2(8) standards of safety, reliability, and compliance with published standards govern at any size, with study scope scaling with system size and FERC jurisdictional analysis as a documentation gate under Section 2(9). Within Division 82, raise the cap to 20 MW as described above.

Workstream 2: Roles, Responsibilities, and Process

What level of Commission review is appropriate for projects with and without local cost recovery?

With local cost recovery: full rubric review, pass or fail documentation gates plus reasonableness factors. Without local cost recovery: streamlined administrative review confirming the process was followed, on a defined notice and comment timeline; interconnection review still applies. The distinction tracks the primary reason for heightened Commission review, which is ratepayer impact. The incorporated Division 82 waiver rule remains available to scale obligations proportionately for good cause.

What type of ongoing support should the PUC provide to local governments?

Addressed in Priority Question 3: the Commission liaison, early stage technical assistance with defining critical loads and resilience objectives, identification and coordination of sources of

funding from ETO or ODOE, and published target review timelines. The coalition does not restate them here.

What materials should the PUC make available to local governments?

Five documents, all published before any community enters the process: the approval rubric, a template community authorization letter, a template municipal resolution, a plain language step by step guide with statutory citations and typical timelines, and the standardized data access NDA. Standardized network topologies under the proposed division serve the same predictability function on the engineering side.

What oversight applies after approval of a community microgrid?

Three elements. A post construction check-in operating as an administrative gate: before local rates take effect, the utility and the community confirm that final costs and conditions match what the Commission approved, with material variances triggering a limited review of the allocation only. A short annual report to the Commission covering performance across grid connected and islanded modes and actual rate impacts against projections. And dispute resolution through the Division 82 arbitration and enforcement provisions incorporated by reference, so no new procedural arrangement is needed.

Workstream 3: Physical and Operational Parameters

Which functions must be required in rule for Track B?

The rule level set is the eight requirements in Priority Question 2: controller functions per IEEE 2030.7 verified per IEEE 2030.8, intentional islanding per IEEE 1547-2018 Clause 8.2 with Clause 8.1 unintentional islanding detection, the executed coordinated operations agreement, the defined operator role with its Section 2(3)(q) limits, system level study of both modes, metering at each PCC, the designated POI boundary switching device, and modification and compliance standards. Rule text should cite IEEE documents with the formulation “or its successor” and note where a cited document is a recommended practice rather than a standard.

Which implementation details belong in utility handbooks?

Utility specific controller settings, telemetry and communication protocols between the controller and utility SCADA, protection settings implementation consistent with IEEE 2030.12 guidance, test forms, and equipment specifications. The dividing line: rules state functions and performance outcomes; handbooks state how a specific utility implements them. Handbooks may not add substantive requirements inconsistent with rule, and a Staff issued non binding methodology guidance document for study depth and modeling tools would protect applicants and utilities alike from utility by utility divergence.

What mechanisms are available to balance risk and operation of microgrids in PSPS zones?

The coordinated operations agreement (COA) is the risk balancing instrument. It should contain a pre-event coordination protocol agreed before any PSPS season: notification sequence, transition procedure, communication paths, and roles. Islanding during a PSPS event is initiated on utility notification, executed by the controller with utility visibility throughout, and the utility's authority over de energization and re energization of its own infrastructure is never displaced (HB 2066 Section 2(3)(q)). Compensation for islanding service during PSPS events should draw

on the value of lost load under Section 2(3)(h)(A). VOLL can enter in at least two ways, as a revenue stream to the microgrid for service delivered during utility initiated shutoffs, or as part of the cost justification within the Interruption Cost Estimate Calculator and benefit cost analysis, and the coalition recommends the workstream weigh those treatments before any position is fixed in rule.

What minimum operational conditions should apply to microgrids in PSPS zones?

Six conditions: an executed COA pre event coordination protocol; islanding initiated on utility PSPS notification rather than unilaterally, with autonomous transition under the COA protocol where de energization occurs without the agreed notification; islanded endurance, fuel or state of charge, sized to the community defined critical load duration documented in the zone application; maintained controller to utility communications during the event; resynchronization only on utility authorization after the utility confirms its infrastructure is safe to re energize; and post event reporting of island performance to the utility and the Commission.

Workstream 4: Cost and Valuation

What feedback do stakeholders have about the two-layered tariff structure?

The coalition supports the two layered structure; it matches the framework stated in Priority Question 5, where the conditions that make it auditable, the limit to shared or common infrastructure, the cost breakout, and the attribution schedule for pre existing DERs, are set out and are not restated here. The coalition will bring an updated representative example to the workstream once the valuation treatment discussed under Workstream 3 is settled.

What control and dispatch obligations should exist for microgrids and utilities?

Two layers of obligation, both specified in the coordinated operations agreement (COA). Automated functions, voltage, frequency, fault response, anti islanding, and sync check, operate continuously without human intervention. Supervisory commands, intentional island initiation, resynchronization, and dispatch coordination with utility system operations, flow through defined communication paths between the microgrid controller and utility SCADA. The microgrid operator dispatches the system's own resources and represents participants; the utility retains exclusive operational control of its distribution infrastructure at all times (HB 2066 Section 2(3)(q)). In exchange, the utility gains a controllable net profile it can use for load management, congestion relief, and deferral. Where an operator coordinates more than one microgrid with or without front of meter energy resources, it may aggregate their controllable net profiles into a single portfolio that operates in parallel with the transmission or distribution system as a resource pursuant to a tariff rate, providing grid services such as peak reduction, transmission and distribution deferral, voltage support, and emergency services, consistent with HB 2066 Section 2(3)(g). The unit offered remains the bounded microgrid operating as a single controllable system. The utility retains exclusive control of its distribution infrastructure at all times (Section 2(3)(q)).

What guidance should the PUC provide about local cost recovery?

Addressed in Priority Question 5. Publishing the allocation methodology together with the rubric, so each project applies the same arithmetic without a rate case, is the single point the coalition adds here.

How should non-participant protections be demonstrated?

Through five mechanisms already embedded in the framework: the rate impact analysis filed with the zone application, including the low income analysis; allocation built on a census by rate schedule administered by the utility within its billing systems, so charges follow actual beneficiaries without disclosing customer identities; the categorical exclusion of income qualified low income customers from local recovery; the boundary alternatives where zones and circuit topology misalign, including the option to decline connection to the microgrid at the project's expense; and the annual report comparing actual rate impacts to projections, with a true up of the local allocation where actual impacts exceed approved projections.

Attachment A. Outline of the Proposed Community Microgrid Systems Division

Numbers are placeholders. The outline is a starting point for Staff drafting; terms the statutes leave open, including third party consultant qualifications, are left to Commission rulemaking.

Rule	Purpose	Implements
X-0005	Purpose and applicability. Governs community microgrid systems within microgrid zones designated by local governments and approved under HB 2066 Section 7. Excludes FERC jurisdictional interconnections; distribution level interconnection serving retail customers is presumed state jurisdictional. Facilities may elect Division 82 review before inclusion in an MSIR.	HB 2065 §§ 2(1)(a), 2(2), 2(9); HB 2066 §§ 2(2), 7
X-0010	Definitions. Nine load bearing definitions drafted below; remaining terms developed in rulemaking.	HB 2065 § 2(1); HB 2066 § 2(1); IEEE 1547-2018, 2030.7
X-0015	Relationship to Division 82. Incorporates the enumerated rules in Attachment B; Division 82 otherwise does not apply to an MSIR. The definitions of the division under which a matter is processed govern that matter.	HB 2066 § 2(2); UM 2111 coordination
X-0020	Microgrid zone designation and approval. A community authorization letter establishes standing for data access; the municipal resolution conditionally designating the zone follows completed engineering and rate impact analysis; the Commission application and published rubric review follow the resolution. Zone designation is the eligibility gateway for an MSIR. Process detail follows the definitions below.	HB 2066 § 7; HB 2065 §§ 2(1)(a), 2(6)
X-0025	Technical data access and utility liaison. Three tier access (T1 public, T2 qualified non public, T3 study execution); twenty one day machine readable response; standardized NDA; denial due process with proposed alternatives.	HB 2065 § 2(6)
X-0030	Feasibility and preliminary design review. Third party consultant option; no cost thirty day design review through that pathway; professional engineer stamped report treated as final. Feasibility defines the zone electrically and geographically and is scoping only, with written utility scope confirmation. For data requests, a consultant is deemed qualified upon designation by the requesting governmental entity; the professional engineer stamp is required for submitted studies, not for data requests. Remaining qualification detail is left to rulemaking.	HB 2065 §§ 2(2)(b), 2(5), 2(7)
X-0035	MSIR application, participant schedule, and queue. The local government, or its designated community microgrid sponsor, files one application with participant schedule (each PCC: customer class, service type, metering) and resource schedule (each new and existing resource and its PoC); one queue position. A scheduled facility is not separately processed under Division 82 absent withdrawal under a procedure preserving the system queue position.	HB 2065 §§ 2(2), 2(7)(c)
X-0040	System impact study. One system level study covering grid connected and islanded modes, with islanding deliverables as a labeled section and an attribution schedule for pre	HB 2065 §§ 2(2), 2(3); HB 2066 § 2(3)(d)

Rule	Purpose	Implements
	existing DERs. Resources already interconnected under Division 82 keep their agreements and receive an operating mode amendment, not restudy.	
X-0045	Standardized network topologies and facility study. Commission adopted, nonexclusive topologies; a conforming MSIR qualifies for the ninety day priority decision; nonconformance affects only that timeline. The final report separates islanding attributable cost from baseline cost and maps it to the HB 2066 § 2(3)(L) categories.	HB 2065 § 2(8)(b); HB 2066 § 2(3)(L)
X-0050	Approval standards and timelines. Utility sole approval authority based on safety, reliability, and published standards; ninety day decision for prioritized applications.	HB 2065 § 2(8)
X-0055	Microgrid controller and operational standards. IEEE 2030.7 functions verified per IEEE 2030.8; intentional islanding per IEEE 1547-2018 Clause 8.2 and unintentional islanding detection per Clause 8.1; PSPS pre event coordination and minimum operational conditions. The controller exchanges signals with, but does not operate, utility distribution equipment.	HB 2066 §§ 2(3)(e), (o), (p), (q); IEEE 2030.7, 2030.8
X-0060	Community microgrid coordinated operations agreement. Commission approved multiparty template covering lifecycle roles, control and dispatch obligations, PSPS protocol, liability, insurance, indemnification, and compensation for utility operational services. Scoped as a shell during the system impact study and executed before energization.	HB 2066 §§ 2(2), 2(3), 2(3)(q)
X-0065	Cost responsibility. Assigns utility operational costs, distribution system improvement costs, and operator costs; defers rate recovery mechanics to Workstream 4. Income qualified low income customers enrolled are excluded from local microgrid rate recovery. Recovery is limited to shared of common infrastructure; privately owned equipment is not rate recovered.	HB 2065 §§ 2(3), 2(6)(e); HB 2066 §§ 2(3)(f), 2(3)(L)
X-0070	Modifications and ongoing compliance. Participant and resource additions, material modification standard, post construction check-in before local rates take effect, and a short annual performance and rate impact report.	HB 2066 §§ 2(2), 2(3)
X-0075	Waivers and disputes. Applies the incorporated Division 82 waiver, arbitration, and enforcement rules.	OAR 860-082-0010, -0080, -0085

Draft text: the nine load bearing definitions and context notes

Microgrid system. A group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that functions as a single controllable system, irrespective of whether the system is operating independently of or in conjunction with the electric grid, consistent with HB 2065 Section 2(1)(b), and that is supervised by a microgrid controller meeting the requirements of rule X-0055.

Community microgrid system. A microgrid system located within a geographical area that a local government designates as a microgrid zone, with the designation approved under HB 2066 Section 7, consistent with HB 2065 Section 2(1)(a). A community microgrid system may serve multiple participants through multiple points of common coupling and points of DER connection on utility infrastructure within the zone.

Microgrid operator. An entity identified as having responsibility for overseeing the coordination of a microgrid's interconnected loads and distributed energy resources and for representing the interests of microgrid participants in interactions with the serving utility, consistent with HB 2066 Section 2(1)(f). The operator functions as an intermediary between participants and the utility and does not assume the utility's role in controlling the utility's own distribution infrastructure (HB 2066 Section 2(3)(q)). A microgrid operator may serve a Track A microgrid or a Track B community microgrid system. Consistent with that role, an operator may coordinate one or more microgrids. Section 2(3)(o) directs the Commission to investigate standards and procedures that would enable an operator to operate one or more community microgrids independently during an emergency, and Section 2(3)(c) calls for approaches that serve a single customer or multiple customers. Where the microgrid(s) with or without front of meter energy resources it coordinates operate in parallel with the transmission or distribution system, the operator may provide the reliability and resilience services those microgrids deliver to that system as a resource pursuant to a tariff rate, and may sell excess energy on a nondiscriminatory basis, consistent with HB 2066 Sections 2(3)(g) and 2(3)(i). The unit the operator aggregates is the microgrid, each a single controllable system within clearly defined electrical boundaries.

Point of common coupling or PCC. A point at which a microgrid participant's electric installation is connected to the serving utility's transmission or distribution system and at which utility metering and billing demarcation for that participant occurs. A microgrid system may include one or more points of common coupling. The underlying definition is consistent with IEEE 2030.7; the metering and billing element is an Oregon division 82 rule addition.

Point of DER connection or PoC. The point at which an individual distributed energy resource is electrically connected within the microgrid system boundary, consistent with IEEE 1547-2018. A microgrid system may include multiple points of DER connection, and a point of DER connection need not coincide with a point of common coupling.

Point of interconnection or POI. The electrical point at which the microgrid system connects to, or disconnects from, the main distribution grid. Island transitions are coordinated by the microgrid controller; where the boundary switching device is utility owned, the utility operates it upon controller signal under the coordinated operations agreement. Where the system boundary includes more than one point of contact with the external grid, one POI is designated and controlled for purposes of integrating the system. Consistent with IEEE 2030.7 Clauses 3 and 4.1.

Microgrid system interconnection request or MSIR. A single application, submitted by the local government or the community microgrid sponsor it designates, for authority to interconnect a community microgrid system, comprising a system description, a participant schedule

identifying each point of common coupling, a resource schedule identifying each new and existing distributed energy resource and its point of DER connection, and a proposed operating description. An MSIR is reviewed as a whole and holds a single queue position.

Microgrid zone. A geographical area that a local government designates as a microgrid zone by resolution under HB 2066 Section 7, subject to Commission approval. A valid designating resolution describes the zone boundary based on existing electric service infrastructure, states the community's resilience goals, acknowledges the analyzed rate impacts, authorizes engagement in the Commission approval process, and states any conditions on the designation.

Community microgrid coordinated operations agreement or coordinated operations agreement. The multiparty agreement among the utility, the microgrid operator, and microgrid participants, executed on the Commission approved template under rule X-0060, governing operation of a community microgrid system in grid connected, transition, and islanded modes and addressing operational roles across the system lifecycle, liability, insurance, indemnification, dispatch and export, and compensation for utility operational services.

Zone designation, Commission application, and approval rubric

The coalition recommends the community led sequence presented to the working group in April 2026. A community authorization letter, signed by the mayor, county administrator, tribal chair, or equivalent authority, establishes the community's standing and accompanies the HB 2065 Section 2(6) data request; no resolution is required to access data. The municipal resolution conditionally designating the zone comes after engineering and rate impact analysis are complete, so the commitment is informed. The resolution then triggers the Commission application under HB 2066 Section 7, supported by the resolution, the professional engineer stamped interconnection study inclusive of a COA, a rate impact analysis including low-income analysis, and community engagement documentation.

Commission review applies a rubric published before any community enters the process. The rubric pairs pass or fail documentation gates (valid resolution, complete PE stamped studies, interconnection and upgrade costs with O&M determined, low income impact analysis, documented community engagement) with reasonableness factors (design likely to achieve the stated resilience goals, proportional rate impacts as validated by the Interruption Cost Estimate Calculator and a benefit cost analysis with the value of resilience and value of lost load factored in, proper consideration of low income and subsidized ratepayers, adequate engagement). Applications without local rate recovery receive streamlined administrative review. Income based eligible customers that qualify as low-income are excluded from local microgrid rate recovery across all participant classes.

Where the zone boundary and circuit topology do not align, the rules should accommodate three alternatives, selected during zone review.

1. **Pay to participate:** customers outside the zone but on the continuous electrical infrastructure of a planned community microgrid may opt in to resilience benefits by rider as local access participants, and the boundary expands by agreement to the relevant circuit segment.
2. **Opt out:** customers on continuous electrical infrastructure outside the zone may decline participation, with any resulting costs borne by the microgrid project rather than the customer.

3. **Multigovernmental designation:** adjoining communities collaborate through an intergovernmental agreement consistent with HB 2066 Section 7, and the zone expands across jurisdictions for shared resilience planning.

Conforming amendments and recommended updates to Division 82

Two conforming amendments implement Track B. First, amend OAR 860-082-0005 to route interconnection of a community microgrid system within an approved microgrid zone to the new division. Second, add a statement that nothing in the new division limits any person's right to seek interconnection of an individual facility under Division 82 before that facility is included in an MSIR.

Three further updates serve Track A and are appropriately coordinated with UM 2111. First, add the microgrid operator definition and role to Division 82, consistent with HB 2066 Sections 2(1)(f) and 2(3)(q), because operators may serve one or more Track A projects as well as Track B systems. Second, align the Division 82 definitions of point of interconnection and point of common coupling with current IEEE usage; Division 82 collapses the two into a single term, losing the distinctions IEEE 1547-2018 draws between the PCC and the point of DER connection, and IEEE 2030.7 draws for the POI as the controlled grid interface. Third, raise the 10 MW nameplate limit in OAR 860-082-0005(1) to 20 MW; the 10 MW figure traces to the 10 MVA scope limit of IEEE 1547-2003, which IEEE 1547-2018 removed, and the federal threshold for small generating facility interconnection is 20 MW.

Attachment B. Disposition of Division 82 Under the Proposed Structure

Rule	Title	Disposition
860-082-0005	Scope and Applicability	Conforming amendment: cross-reference routing MSIR systems to the new division; Division 82 election preserved for individual facilities.
860-082-0010	Waiver	Incorporated by reference.
860-082-0015	Definitions	Some are applicable to an MSIR; the new division's definitions govern. Recommended update: add microgrid operator; align POI and PCC with current IEEE definitions.
860-082-0020	Pre-Application Process	Replaced by X-0025 and X-0030 (HB 2065 §§ 2(6), 2(7)).
860-082-0025	Applications to Interconnect a Small Generator Facility	Replaced by the MSIR application rule (X-0035).
860-082-0030	Construction, Operation, Maintenance, and Testing of Small Generator Facilities	Partially incorporated: per-resource construction and testing apply where consistent with the coordinated operations agreement.
860-082-0033	Export Controls	Not applicable; export and dispatch governed by the coordinated operations agreement.
860-082-0035	Cost Responsibility	Replaced by X-0065.
860-082-0040	Insurance	Incorporated by reference; allocation per the coordinated operations agreement.
860-082-0045	Tier 1 Interconnection Review	Not applicable; Track A pathway.
860-082-0050	Tier 2 Interconnection Review	Not applicable; Track A pathway.
860-082-0055	Tier 3 Interconnection Review	Not applicable; Track A pathway.
860-082-0060	Tier 4 Interconnection Review	Not applicable; Track A pathway. The MSIR study sequence retains Tier 4's Feasibility, System Impact Study, and Facilities Study nomenclature for continuity with utility practice.
860-082-0063	Supplemental Review	Not applicable to an MSIR.
860-082-0065	Recordkeeping and Reporting Requirements	Incorporated by reference.
860-082-0070	Metering and Monitoring	Incorporated at each PCC; system monitoring per X-0055.
860-082-0075	Temporary Disconnection	Incorporated by reference, with coordination per the coordinated operations agreement.
860-082-0080	Arbitration of Disputes	Incorporated by reference.
860-082-0085	Complaints for Enforcement	Incorporated by reference.