Rule 024 engagement questionnaire

Comments from *(company/stakeholder name)*:	Alberta Cogeneration Development Council (ACDC)	**Contact name *(for companies)*:**	Benoit Trudeau, CEO
Date [yyyy/mm/dd]:	2026/09/04	**Phone:**	[redacted]
Role:	Industry association — Alberta cogeneration / micro-CHP sector; microgeneration proponent	**Email**:	[redacted]

Instructions

1. Please download this document, save as "**Rule 024 questionnaire**" and fill out the demographic/contact information above.

2. Please review Bulletin 2026-10.

3. In the box above, please provide your name, your organization's name (if applicable), and the role(s) that best describe(s) your participation in the microgeneration field (customer, consultant, developer, distribution facility owner, transmission facility owner, government agency, non-governmental organization, microgeneration proponent, etc.).

4. Some of the questions included in this engagement apply only to specific roles (such as microgeneration customer/proponent, distribution facility owner, etc.). Please only answer questions relevant to your self-identified role(s) and/or experience. You do not need to complete every question to participate in this engagement. Incomplete questionnaires will be accepted.

5. Where you provide any recommendations, please include reasons or justifications.

6. Submit your response to engage@auc.ab.ca. In the email, please include the following subject line: **Rule 024 engagement**.

Questions

Timelines

1. Please briefly describe your experience with the timelines to connect microgeneration generating units. Where applicable, please explain any differences between the connection for small (<150 kW) and large (150 kW – 5 MW) microgeneration generating units.

ACDC is the Alberta industry association for cogeneration and micro-combined heat and power (mCHP). Our members supply, engineer, install, develop and host mCHP units in both the small (<150 kW) and large (150 kW – 5 MW) microgeneration categories.

Two characteristics of mCHP are fundamental to the comments that follow, and both are frequently misunderstood in the connection process.

First, only the electrical side of an mCHP unit is ever connected to the interconnected electric system. An mCHP unit is a fuel-fired engine or turbine directly coupled to an electrical generator. The heat that the engine would otherwise reject — through the jacket, the oil cooler and the exhaust — is recovered into the host site's own hot water or glycol loop and used for space heating, domestic hot water or process heat on that site. That thermal equipment is not connected to the interconnected electric system, to any thermal or district-heating grid, or to any facility of the distribution facility owner. It sits entirely behind the customer's meter, in the same category as the site's boiler or hot water tank, and it is regulated under the Safety Codes Act and the applicable mechanical, boiler and gas codes.

Second, most mCHP unit produces alternating current directly. The generator is a synchronous or induction machine coupled to the engine shaft. There is no photovoltaic array, no battery and no DC stage anywhere in the unit. Section 1(d) of the proposed Rule 024 defines an inverter as "an electronic device that converts DC electricity into AC electricity". Most mCHP unit have no DC electricity for an inverter to convert.

On timelines specifically:

Small (<150 kW). Where the application is processed as filed, the framework in Rule 024 works: 14 days for the owner to confirm a complete Form A, and 30 days for the Commission on a notice of dispute. Where it does not work, the delay is almost never caused by the physical connection, which for a unit of this size is routine. It is caused by interpretive questions — how the owner determines the maximum permitted size of the unit, and whether the owner requires inverter-based equipment for a machine that already generates AC. Either can add months to a project that presents no unusual electrical characteristics.

Large (150 kW – 5 MW). Timelines are inherently longer because a system impact or protection co-ordination study is required, and our members accept that. The same interpretive questions arise, earlier and at greater cost, because the customer must commit to detailed engineering before the permitted size of the unit is settled.

The distinction ACDC would draw to the Commission's attention is therefore not small versus large. It is the routine case versus the interpretive-dispute case. The first is workable today. The second is where mCHP projects in Alberta are lost.

2. Have you observed or experienced delays in the microgeneration connection process? If yes, please explain the main contributing factors.

Yes. In our members' experience the main contributing factors for mCHP projects are the following, in order of impact.

1. Treatment of the site's thermal energy consumption when the permitted size of the unit is determined.

Section 1(1)(h)(ii) of the Micro-generation Regulation requires that the unit be "intended to meet all or a portion of the customer's total annual energy consumption at the customer's site or aggregated sites". Section 2 of Rule 024 uses the same language: "the customer's total energy consumption".

Some owners read "energy consumption" as "electricity consumption" and cap the unit at the site's annual kilowatt-hours. The text does not support that reading. Where the Regulation means electricity it says so expressly — subclause (i) speaks of a unit that "exclusively uses sources of renewable or alternative energy to supply electric energy", and subclause (iv) of a unit that "supplies electric energy only to a site". Subclause (ii), the sizing provision, deliberately does not. It says energy. A site that burns 3,000 GJ of natural gas a year for heat consumes that energy as surely as it consumes kilowatt-hours, and an mCHP unit is purchased precisely in order to serve it.

The same conclusion follows from Section 1(1)(l)(ii) of the Regulation, which sets the greenhouse gas intensity test against either "the electric energy produced" or "the total energy produced from the simultaneous generation of electric energy and production of thermal energy from the same fuel source". The Regulation already recognizes cogeneration expressly, and already counts recovered thermal energy as energy. It would be incoherent to count that thermal energy when testing emissions and to disregard the site's thermal consumption when testing size.

The practical consequence of the narrow reading is that the unit is capped below the size needed to carry the site's heat load. The customer is then asked to buy a machine that cannot do the job it was bought for, and the project is abandoned.

2. Inverter requirements imposed on machines that already generate AC.

Members have been asked by distribution facility owners to rectify the AC output of an mCHP generator to DC and then re-invert it through inverter equipment of the type used for solar photovoltaic installations. There is no technical basis for this. The unit produces grid-frequency AC at the generator terminals; the added conversion introduces capital cost, standing conversion losses and an additional point of failure, and it removes the inherent short-circuit contribution and inertia that a rotating machine provides. The only apparent reason for the requirement is that the owner's interconnection procedure was written around inverter-based solar and has no category for a directly connected rotating machine. Resolving it consumes weeks of correspondence on every project, and in some cases the added cost has ended the project.

3. Review of, or cost attribution to, the thermal side of the unit.

Some owners' review processes reach into the mCHP's heat recovery equipment — heat exchangers, circulation pumps, storage tanks, controls — and request engineering, review or cost recovery in respect of it. None of that equipment is connected to the interconnected electric system. It is behind the meter and is already regulated under the Safety Codes Act and the applicable mechanical, boiler and gas codes, administered by the accredited safety codes authority. Reviewing it a second time in the electrical connection process adds delay and cost without adding safety.

4. Absence of published, technology-specific guidance.

Owners' published microgeneration material is written for inverter-based solar. There is no published statement of how the permitted size of a cogeneration unit is calculated, and no published interconnection requirement set for a directly connected rotating AC machine. Each application therefore becomes an individual negotiation, and the outcome varies between service areas and between reviewers within the same service area.

a. If yes, is there more information that distribution facility owners could provide before the start of a microgeneration project to help reduce delays? Please comment on each of the suggestions below:

Yes. Publishing a small amount of technology-specific information in advance would remove most of the delay our members experience. Our comments on the specific suggestions follow.

i. General information about phases of the connection process and associated minimum timelines.

Strongly support. Owners should publish, for each phase, what the phase consists of, what the customer must supply, the minimum and typical duration, and what causes a phase to restart. Our members' principal difficulty is not that a phase takes time; it is that neither the customer nor the proponent can tell whether a project is progressing normally or has stalled.

ii. Comparison between connection timelines, phases, and other requirements for small and large microgeneration projects.

Strongly support. The comparison should also distinguish by interconnection type, not only by size. A 100 kW inverter-based solar array and a 100 kW directly connected rotating AC machine are in the same size category but raise entirely different protection, study and commissioning requirements. Published material that addresses only the solar case leaves proponents of every other technology to discover the requirements one letter at a time.

iii. An explanation of common circumstances that may lead to delays in the connection process or restarts of phases (including delays in customer/microgeneration proponent responses to owners' questions).

Strongly support, and we would ask that the explanation expressly cover the circumstances our members encounter:

• how the owner calculates the maximum permitted size of the unit, and specifically how the site's annual thermal energy consumption is treated in that calculation;

• what interconnection requirements apply to a unit that generates AC directly, as distinct from an inverter-based unit, and the standard relied on for each;

• what the owner does and does not review on the customer's side of the meter; and

• what triggers a restart of a phase, and what the customer can do to avoid it.

iv. Other (please explain).

ACDC asks that each distribution facility owner publish two short written statements. Neither requires a rule change and both would eliminate the great majority of the delay our members experience.

(a) Sizing methodology. A plain statement of how the owner determines the maximum permitted nameplate capacity under Section 1(1)(h)(ii) of the Micro-generation Regulation, including how the site's annual thermal energy consumption in gigajoules is converted and included. ACDC proposes the following, which uses only the standard energy conversion and the site's own service rating:

Energy basis = annual electrical consumption (kWh) + [annual on-site thermal energy consumption (GJ) × 277.78 kWh/GJ]

Capacity basis = the site's peak electrical demand (kVA), on the same basis the owner sizes the customer's transformer and service, and within the rating of that service under Section 1(1)(h)(iii)

Maximum permitted size = the energy basis and the capacity basis taken together; both are measures of the same customer's own requirement, and neither alone states it

Both terms are required because Section 1(1)(h)(ii) permits a unit to meet all of the customer's total annual energy consumption, not merely a portion of it. An mCHP unit is dispatchable and available up to 8,760 hours a year, so unlike an intermittent resource it can be expected to produce the whole of its site's energy needs, and its owner sizes and finances it on that expectation. A unit held instead to the site's average annual electrical draw, with its thermal output disregarded, cannot serve the site in any hour in which the site's demand exceeds that average — so the "all" the Regulation allows is unavailable in practice, whatever the arithmetic shows on an annual basis. Sizing on the energy basis and the capacity basis together is what gives the words of Section 1(1)(h)(ii) their effect.

The peak figure requires no estimate and no new metering. Where the site is served by an interval meter, the distribution facility owner already holds the site's recorded demand at 15-minute intervals and releases it to the customer or the customer's authorized agent on request — the customer load data release each owner provides, in the daily interval meter (DIM) format prescribed by the Settlement System Code, Rule 021. ACDC proposes that the capacity basis be taken as the highest recorded 15-minute demand over the most recent twelve months of that data, converted to kVA at the site's power factor, and that the owner state in its published methodology that it will accept that figure. Twelve months is the right window because it captures the site's winter and summer extremes and the seasonal shape of

its load, which an annual total conceals entirely. Where the site has no interval meter, the highest billed monthly demand over the same twelve months should be accepted in its place.

ACDC asks that this calculation be treated as a baseline rather than as a ceiling. Its purpose is to establish the size the owner agrees to on the site's documented historical consumption — a common starting point both sides can rely on, arrived at without negotiation and without discretion. It leaves the owner's existing practice on future load intact. A customer who intends to install new equipment — electrification of a process, added refrigeration or compressed air, an expansion, added heating or cooling load, electric vehicle charging — should continue to be able to substantiate a unit larger than the historical figure supports, on the documentation the owner asks for today: the equipment specifications, its connected load and expected duty, and the timing of the installation. That is already how owners deal with these requests, and ACDC does not propose to change it. What ACDC seeks is that the two be kept distinct: an agreed baseline on the historical figures, and any increment above it assessed case by case on the customer's evidence, as it is now. With the baseline agreed, the ordinary request proceeds on settled ground and the owner's discretion is reserved for the cases that genuinely call for it — which is where the delay described in our answers below would be removed.

(b) Interconnection requirements by generator type. A statement of which requirements apply to inverter-based units and which apply to units that produce AC directly from a rotating machine, with the governing standard cited for each. Members are presently asked to satisfy requirements drawn from inverter-based standards that have no application to a synchronous or induction generator, and there is no published document against which the request can be checked.

b. If yes, is there more information that customers or microgeneration proponents could provide in their initial microgeneration applications to help reduce delays? Please comment on each of the suggestions below:

Yes. Proponents can and should file more at the outset, provided the owner has first published what it will do with the information. Our comments on the specific suggestions follow.

i. More accurate or detailed information about the technical specifications of their microgeneration project.

Support. For an mCHP unit, ACDC recommends that the following be filed with the initial notice as a matter of course:

• nameplate electrical capacity and the generator type — synchronous or induction, directly coupled, producing AC at grid frequency, with no DC stage and no inverter (when it applies);

• the proposed protection scheme and the standard relied on, including anti-islanding and interconnection protection appropriate to a rotating machine;

• expected annual electrical output;

• recoverable thermal output and the on-site loads it will serve; and

• fuel input and the greenhouse gas intensity calculation under Section 1(1)(l)(ii) of the Micro-generation Regulation, on the cogeneration basis the Regulation provides.

Filing the generator type explicitly at the outset is important. It is the single item that most often prevents an owner from defaulting to an inverter-based requirement set that does not apply to the unit.

ii. Justification for the proposed microgeneration project's size with reference to the customer's annual energy consumption and evidence of any planned future upgrades.

Support in principle, but it cannot work until the calculation is settled. A proponent cannot justify the size of a unit against "the customer's total annual energy consumption" while the owner and the proponent are using different meanings of that phrase.

ACDC's position is that for a cogeneration unit the customer's total annual energy consumption comprises both the electrical energy and the thermal energy consumed at the site, for the reasons set out in our answer on delays above and in our answer on the sizing restriction below. On that basis a proponent can and should file:

• twelve months of electricity consumption from the site's bills, in kWh;

• twelve months of on-site thermal energy consumption in GJ, from natural gas bills or, for a new building, from the design heating and process load calculation;

• twelve months of the site's recorded demand at 15-minute intervals, from the owner's own customer load data release in DIM format under the Settlement System Code, Rule 021, together with the highest recorded demand taken from it in kVA;

• the conversion of the thermal figure at 277.78 kWh per GJ, and the resulting combined annual consumption; and

• the proposed unit's expected annual electrical output shown against that figure, together with any documented planned change in site load.

Our members are prepared to file all of this at the outset. What they need first is the Commission's confirmation of the basis on which it will be assessed.

iii. Other (please explain).

Where the customer's thermal load is a material part of the justification for the size of the unit, the proponent should file the supporting documentation with the initial notice rather than on request — gas bills or a stamped load calculation, and the heat recovery duty of the proposed unit. This removes any question of an unverified assertion and lets the owner complete its size review inside the 14-day window.

3. In your experience, how often are delays linked to the *Micro-generation Regulation*'s restriction of maximum microgeneration generating unit size to "all or a portion of a customer's total annual energy consumption"? Please explain.

Very frequently — in our members' experience this is the single largest source of delay for cogeneration projects, and the most common reason a project is abandoned before it reaches a connection cost discussion at all.

The restriction itself is not the problem. ACDC supports it: a microgeneration unit should serve the site. The problem is that the phrase "total annual energy consumption" is read by some owners as "total annual electricity consumption", and there is nothing published to which a proponent can point to settle the question.

The text does not support the narrow reading. Section 1(1)(h) of the Micro-generation Regulation uses "electric energy" three times — in subclauses (i), (iv) and elsewhere — and in subclause (ii), the sizing test, it uses "energy consumption" without qualification. Section 2 of Rule 024 does the same. Where the drafter meant electricity, the drafter wrote electricity.

The structure of the Regulation confirms it. Section 1(1)(l)(ii)(B) qualifies a unit by reference to "the total energy produced from the simultaneous generation of electric energy and production of thermal energy from the same fuel source". The Regulation therefore already contemplates cogeneration and already treats recovered thermal energy as energy for the purpose of admitting the unit. Counting thermal energy on the emissions test and disregarding the site's thermal consumption on the sizing test produces an internally inconsistent result: a technology the Regulation expressly qualifies is then sized as though its secondary output did not exist.

What the narrow reading does to a project. A unit sized only to the site's electrical consumption is, for most Alberta host sites, roughly half the size the site's heat load requires. The recovered heat then displaces only part of the boiler load, the boiler continues to run, the fuel efficiency case collapses and the payback moves outside any commercial range. The proponent's choice is to accept a unit that does not do the job or to abandon the project. Most abandon it.

Capacity, not only average annual energy. The second element of the same problem is that the sizing test is applied as an annual average, which takes no account of the site's capacity requirement. A site is served by a transformer and a service sized to its peak demand in kVA, not to its average kWh draw, and the customer pays for that

capacity. The Regulation itself recognizes the distinction: Section 1(1)(h)(iii) bounds a unit by the rating of the customer's service, which is a capacity figure, while subclause (ii) speaks to annual energy. Unlike solar photovoltaic or wind, an mCHP unit is dispatchable and available up to 8,760 hours a year, and is properly assessed as base load rather than as an intermittent resource. Sized against average annual consumption alone, the unit is held to the site's average rather than to its real requirement, and cannot carry the site's own peak. Applied that way the two limitations compound: the unit's thermal output is disregarded on one side and the site's capacity requirement on the other, with the result that a technology capable of running 8,760 hours a year is prevented from meeting the "all" of its site's energy needs that Section 1(1)(h)(ii) expressly permits. ACDC's position is that a cogeneration unit should be permitted to serve up to 100 per cent of its owner's requirement measured on three factors taken together: annual electrical consumption in kWh; peak electrical demand in kVA, on the same basis the owner deals with its transformer and service along the distribution network; and annual thermal consumption, taken from metered gas consumption in gigajoules and converted at 277.78 kWh per gigajoule.

What ACDC asks. A single clarification, in Rule 024 or in Commission guidance, to the effect that for a micro-generation generating unit that simultaneously generates electric energy and produces useful thermal energy from the same fuel source, the customer's total annual energy consumption for the purposes of Section 1(1)(h)(ii) of the Micro-generation Regulation includes both the electrical energy and the thermal energy consumed at the customer's site or aggregated sites, with thermal energy converted at 277.78 kWh per gigajoule. ACDC further asks the Commission to confirm that the permitted size of such a unit may reflect the site's peak electrical demand in kVA, consistent with the rating of the customer's service contemplated by Section 1(1)(h)(iii), and is not constrained to the site's average annual draw.

This changes nothing for solar photovoltaic, wind or any single-output technology, where the site's electrical consumption remains the operative figure. It resolves the ambiguity only for the technology to which the ambiguity is peculiar, and it does so without altering the policy that the unit must serve the customer's own consumption.

4. **[Customers/microgeneration proponents only]** Are you generally aware of each of the following? For each ‘no’, please suggest how the information could be provided more accessibly.

Our comments on each follow.

a. Legislative requirements applying to microgeneration in Alberta.

Yes, aware. Our members are familiar with the Micro-generation Regulation, Rule 024 and the associated forms. The gap is not awareness of the instruments; it is that the instruments do not address cogeneration expressly, so awareness of them does not produce a predictable answer on the two questions that matter to our members — permitted size and interconnection requirements for a directly connected AC machine.

b. Differences between microgeneration, small scale generation, and distribution-connected generation.

Aware, but the distinction is poorly understood in the wider market. Site owners approaching cogeneration for the first time frequently do not know which regime their project falls under, and the choice materially affects timeline, cost and compensation. A single AUC page setting the three regimes side by side — eligibility, size limits, process, compensation — would be of real practical use, and would be more accessible than the current requirement to read three instruments and infer the comparison.

c. The terms and conditions of service that apply to microgeneration generating units in each distribution facility owner’s service area.

Only partially, and with difficulty. The terms and conditions are published, but the microgeneration material within them is written around inverter-based solar and is silent on cogeneration. Locating the applicable requirement for a directly connected rotating AC machine generally requires correspondence with the owner rather than reading the published document, and the answer has varied between service areas and between reviewers.

Suggestion: each owner should publish a short microgeneration technical requirements summary organized by generator type — inverter-based, and directly connected rotating machine — citing the governing standard for each requirement, and the AUC should link to those summaries from a single page on its website.

5. **[Distribution facility owners only]** How many large microgeneration applications have you received in each year since 2023?

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6. **[Distribution facility owners only]** How many large microgeneration projects have been cancelled in your service area after their application (i.e., Form A) was approved, and what are the general reasons for this (change to customer's plans, timeline delays, not enough available capacity, etc.)?

Click or tap here to enter text.

   a. Are these projects typically cancelled after a specific step or milestone in the connection process (e.g. after a detailed level study, engineering/technical review, etc.)?

Click or tap here to enter text.

   b. How likely are large microgeneration projects to be cancelled after their application is approved compared to small microgeneration projects? Please provide a percentage comparison, if available.

Click or tap here to enter text.

      i. Are there certain types of large microgeneration projects (e.g., specific fuel types, projects in certain areas, etc.) that are more likely to be cancelled than other types of large microgeneration projects? Please explain.

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ii. What sort of information could be provided to customers and microgeneration proponents, ahead of initial application submission, that could help decrease the number of cancelled large microgeneration projects?

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7. Are participants in the microgeneration market, especially customers and microgeneration proponents, generally aware of the *Small Scale Generation Regulation?*

In our members' experience, awareness of the Small Scale Generation Regulation among site owners considering cogeneration is limited. Proponents and consultants are generally aware of it; customers usually are not, and typically learn of it only when a project is found not to fit the microgeneration framework.

a. Would greater awareness of the *Small Scale Generation Regulation* alleviate some issues with microgeneration applications? Please explain

To a degree. Greater awareness would help a site owner whose project genuinely does not fit microgeneration — for example because generation would exceed site consumption — to identify the correct route sooner instead of pursuing a microgeneration application that cannot succeed.

It would not, however, address the difficulty our members raise. A cogeneration unit properly sized to the site's combined electrical and thermal consumption is squarely within the microgeneration framework and belongs there. Directing such projects to the small scale generation regime because of an ambiguity in how their size is assessed would impose a substantially heavier process on projects the Micro-generation Regulation was intended to accommodate.

b. **[Distribution facility owners only]** Have you connected any customers as small scale or community generators?

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Cost estimates

1. Do cost estimates for a microgeneration project connection typically change over the connection process? If so, please describe the circumstances.

Yes. For mCHP projects the estimate typically changes for one of three reasons, and only the third is a genuine engineering development:

(a) The size question is reopened. The estimate is prepared against the unit as proposed; the permitted size is then disputed; the unit is resized; the estimate is redone. Because the size question is usually raised after the initial cost discussion rather than at the completeness review, the cost work is done twice.

(b) An inverter requirement appears. An estimate prepared for a directly connected rotating machine is revised to include rectification and inversion equipment, and the associated engineering, after the owner applies an inverter-based procedure to the unit. This can be a large proportion of the total, and it is a requirement that in our submission should not be applied to the unit at all.

(c) Genuine site findings. Available capacity on the feeder, transformer condition, or protection co-ordination findings from the study. Our members regard these as normal and expect them.

Categories (a) and (b) are avoidable and are the ones that damage confidence in the process, because from the customer's perspective the price of the same unchanged project has moved for reasons the customer cannot connect to anything physical.

a. What information could be provided, by distribution facility owners, customers, or both, that might reduce the likelihood or frequency of cost estimates changing significantly during the connection process?

From distribution facility owners:

• a published statement of how the permitted size of a cogeneration unit is calculated, including the treatment of the site's annual thermal energy consumption, so that the size question is settled before costing rather than after;

• a published statement of which interconnection requirements apply to a unit producing AC directly from a rotating machine and which apply only to inverter-based units, with the standard cited for each, so that no requirement can be added mid-process without an identifiable basis; and

• an itemized estimate distinguishing costs on the owner's system from any costs the owner attributes to the customer's side of the meter, and confirming that no cost relates to equipment not connected to the interconnected electric system.

From customers and proponents:

• the site's twelve-month electrical consumption in kWh and thermal energy consumption in GJ, filed with the initial notice;

• the generator type, protection scheme and governing standard, stated expressly at the outset; and

• the site single-line diagram and the service rating.

If both sides file their part at the beginning, the two questions that currently move estimates are resolved before the estimate is prepared.

2. In your opinion, at what point in the microgeneration connection process should a customer be informed of the potential to be charged for extraordinary costs?

At the owner's 14-day response under Section 3(3) of Rule 024, at the latest — that is, at the same time the owner confirms whether the notice and required documents are complete.

The owner is not in a position to finalize a figure at that point, and ACDC does not suggest that it should be. What the owner can state is whether, on the information filed, extraordinary costs are reasonably likely to be claimed, the general nature of the items concerned, and when a finalized estimate is expected. That single sentence lets the customer decide whether to continue investing in the project.

The present practice on our members' projects is that the possibility surfaces late, after the customer has committed to design and equipment. A customer who learns at that stage that a substantial direct reimbursement may be required has already spent money that a two-line early disclosure would have saved.
ACDC also asks the Commission to consider an outer limit on the time an owner may take to finalize its cost estimate following the Section 3(3) completeness response. Early disclosure of the possibility of extraordinary costs is of limited value if the figure itself remains open indefinitely: the customer is told a cost may be coming but cannot size it, cannot finance it and cannot decide whether to proceed. A defined outer limit, extendable by the owner on notice to the customer stating the reasons for the extension and the date by which the estimate is expected, would preserve the flexibility owners need on genuinely complex projects while giving the customer a date to plan against. ACDC does not propose a specific number of days and would defer to the Commission and the owners on what is workable.

Technical standards

1. Do technical standards associated with a microgeneration unit connection typically change over the connection process? If so, please describe the circumstances.

Yes — and for mCHP this is the most consequential of the changes our members encounter.

The recurring circumstance is this. The application is filed for a unit that produces alternating current directly: a fuel-fired engine driving a synchronous or induction generator, connected to the site's electrical system at grid frequency, with no photovoltaic array, no battery, no DC bus and no inverter anywhere in the unit. During review, the owner applies its microgeneration interconnection procedure. That procedure was written for inverter-based solar. The requirements that follow — inverter certification, inverter-based anti-islanding functions, inverter setting schedules — have no application to a rotating machine, and in several cases members have been directed to rectify the generator's AC output to DC and re-invert it through inverter equipment of the type used for solar installations so that the unit will fit the procedure.

That direction is technically unsound. It adds capital cost and permanent conversion losses to a machine whose output is already at grid voltage and frequency; it inserts an additional failure point in series with the generation; and it removes the fault current contribution and rotating inertia that a directly connected synchronous machine provides to the distribution system and that inverter-based generation does not. Nothing about the system's safety or reliability is improved by it.

ACDC notes that the proposed Rule 024 adds a definition of "inverter" at Section 1(d): "an electronic device that converts DC electricity into AC electricity". ACDC supports the addition — the definition is correct — and asks the Commission to draw the consequence from it. Most mCHP unit produces no DC electricity. There is nothing for an inverter to convert, and requirements framed around inverters cannot apply to it.

Interconnection requirements for directly connected rotating machines are well established — interconnection protection, anti-islanding by protective relaying rather than by inverter function, synchronizing equipment, and the protection co-ordination study appropriate to the machine. Our members are ready to meet them in full. What they should not be required to do is convert an AC machine to DC and back so that it resembles a solar array.

   a. What information could be provided, by distribution facility owners, customers, or both, that might reduce the likelihood or frequency of technical standards changing partway through the connection process?

A single published document per owner would resolve almost all of it: a microgeneration interconnection requirements summary organized by generator type — inverter-based units on one side, directly connected rotating AC machines on the other — stating for each requirement the governing standard and the clause relied on.

With that document in existence, a requirement introduced part-way through a project can be checked against a published basis, and a requirement that has no basis will not be introduced. Without it, the requirement set is whatever the reviewing engineer's procedure contains, and mid-process change is inevitable.

ACDC would also ask that the Commission consider stating, whether in Rule 024 or in guidance, that requirements applicable to inverter-based micro-generation generating units do not apply to units that produce alternating current directly and contain no inverter as defined in Section 1(d). This is a clarification of existing law rather than a change to it, and it would settle the question across every service area at once.

Communication

1. Please briefly describe your experience with communication between distribution facility owners, customers, and any other participants during the microgeneration unit connection process.

Communication on our members' projects is generally courteous and made in good faith on both sides. The difficulty is structural rather than personal, and it has two parts.

Nothing is written down that both sides can point to. Because there is no published owner position on how a cogeneration unit's permitted size is calculated, or on which interconnection requirements apply to a rotating AC machine, the exchange becomes an argument between two readings of a regulation rather than an application of a published rule. Neither party can close it, and it escalates by default.

The customer is a third party to a technical conversation about their own project. The substantive exchange happens between the owner's engineer and the proponent. The site owner — who is spending the money — receives the outcome, often as a size reduction or a cost increase, without the reasoning. In our members' experience this is the point at which site owners disengage from cogeneration entirely.

2. How often **do** distribution facility owners provide updates to customers on the status of their proposed microgeneration projects? Please comment on any differences between small and large microgeneration generating units.

Practice varies considerably between owners and between projects within the same owner. Some members report regular unprompted updates; more commonly, status information is available when requested but is not offered, and long intervals pass with no communication during technical review. The variation is greater for large units, where review periods are longer and the silence correspondingly harder for a customer to interpret.

3. In your opinion, how often **should** distribution facility owners provide updates to customers on the status of their proposed microgeneration projects? Please consider one or more of the below options, provide justification, and comment on any differences between small and large microgeneration generating units.

ACDC's view is that milestone-based updates are more useful than calendar-based ones, with a calendar backstop so that a project cannot go silent indefinitely. Our comments on each option follow.

a. Every 14 days

Support as a backstop, not as the primary mechanism. A 14-day update that says nothing has changed has limited value, but a guarantee that no more than 14 days will pass without contact is valuable, because it tells the customer that silence means work in progress rather than a file that has stalled.

b. When the project enters a new phase

Strongly support — this should be the primary trigger. Phase transitions are the points at which the customer may need to act, commit funds or provide information. Notification at each transition, identifying the phase entered and what is expected of the customer, would address most of the uncertainty our members report.

c. When the distribution facility owner receives new information that may necessitate changes to the microgeneration project's specifications

Strongly support, and in our submission this is the most important single trigger. Where the owner forms a view that would change the size of the unit, its protection requirements or its cost, the customer should be told at that point rather than in the eventual formal response. For mCHP this covers precisely the two circumstances that damage projects: a view forming on the permitted size of the unit, and a view forming that inverter-based equipment will be required. Both are presently communicated late, after the customer has committed to design and equipment.

d. When information is about to become outdated due to lack of customer response

Support. A notice that information is about to expire, sent before it expires, is more efficient for both parties than a phase restart afterwards.

e. Other

One further trigger: the owner should notify the customer when the owner first forms the view that extraordinary costs may be claimed, at the time that view is formed and not when the estimate is finalized. This is consistent with our answer on the timing of extraordinary cost disclosure above.

3. In your opinion, what are the most effective methods for distribution facility owners and customers to exchange necessary information in a timely fashion? In considering the below options, please take into account the required resources (time, staffing, or other).

The principle ACDC would apply is that the substance should be published and the correspondence should be specific. Most of the exchange volume on our members' projects consists of questions that a published document would have answered. Our comments on each option follow.

a. Direct emails/phone calls

Effective for project-specific matters and should remain the primary channel, provided the substantive positions taken are confirmed in writing. Where a requirement is stated only by telephone, the proponent has nothing to check it against and nothing to rely on later.

b. In-person or virtual meetings

Valuable, and under-used, for the specific case of a first-of-type unit in a service area. A single early meeting between the owner's engineer and the proponent's engineer, before formal review, resolves in an hour what otherwise takes weeks of correspondence — particularly the generator type and the applicable protection requirements. ACDC would encourage owners to offer such a meeting where the technology is one they have not previously connected.

c. Updates to distribution facility owners' websites as soon as relevant new general or system-wide information is known

Strongly support. This is where the sizing methodology and the generator-type requirement summaries described in our earlier answers belong. General information that every proponent needs should be published once rather than transmitted individually on each project.

d. General communication in a centralized hub, such as the AUC's website

Support. A single AUC page linking to each owner's microgeneration requirements, terms and conditions, and current contact point would be of practical value, particularly to proponents working across multiple service areas who presently maintain their own list.

ACDC would not favour centralising project-specific communication, which properly stays between the customer, the proponent and the owner.

e. Other

Owners' published microgeneration material should state the date of last revision and identify which technologies it addresses. Material that is silent on its scope is read by proponents as applying to all microgeneration, which is how requirements written for solar photovoltaic come to be applied to cogeneration units.

4. In your opinion, what changes to existing communication processes between microgeneration parties would lead to better outcomes, such as minimizing delays in the connection process?

In order of expected effect:

1. Publish the two documents that do not presently exist. A sizing methodology statement, including how the site's annual thermal energy consumption is treated; and an interconnection requirements summary organized by generator type, citing the governing standard for each requirement. Most of what is currently communicated by correspondence would not need to be communicated at all.

2. Front-load the two determinations that presently arrive late. At the 14-day completeness response under Section 3(3), the owner should state whether the proposed size appears acceptable on the information filed, and whether extraordinary costs appear reasonably likely. Neither needs to be final. Both let the customer make an informed decision before committing further funds.

3. Confirm substantive positions in writing, with the basis. Where a requirement is imposed or a size reduction is proposed, the written communication should identify the provision or standard relied on. This alone would resolve the inverter question on most projects, because the requirement cannot be sourced to any standard applicable to a rotating AC machine.

4. Notify at phase transitions, with a 14-day backstop.

5. Copy the site owner, not only the proponent, on decisions that change the size, cost or schedule of the project.o

5. Please briefly describe your experience with microgeneration applications where the proposed size must be reduced for legislative, technical, safety, or other reasons. How has this been communicated?

Our members' experience of size reductions is that they are seldom driven by a technical constraint on the distribution system. In the large majority of cases the reduction follows from the owner's reading of the sizing test in Section 1(1)(h)(ii) of the Micro-generation Regulation — the unit is said to exceed the site's annual electricity consumption — rather than from available capacity, thermal rating or protection findings.

The communication typically takes the form of a statement that the proposed unit exceeds the maximum permitted size, with the site's annual kWh given as the operative figure. What it does not contain is the reasoning: why the site's thermal energy consumption, which the unit exists to serve, has been excluded from the calculation. The site owner reads a definitive statement of a legal limit, is given no basis on which to test it, and generally accepts it or abandons the project. Very few pursue the dispute mechanism, which is a poor measure of how often the underlying question is contested.

Where the reduction does arise from a genuine technical constraint — feeder capacity, transformer rating, protection co-ordination — our members report that it is explained clearly and accepted without difficulty. The difference in the quality of the explanation is itself informative: owners explain well what their published procedures cover, and poorly what those procedures do not address.

a. When the rationale for such reductions is communicated, what options for proceeding with the microgeneration project are generally provided to customers?

The options presented are generally to accept the reduced size, to dispute, or to withdraw.

For cogeneration the first is frequently not a real option. Unlike a solar array, a cogeneration unit cannot be scaled down proportionally and remain viable. Its economics rest on the recovered heat displacing purchased fuel; a unit sized below the site's heat load leaves the boiler running, forfeits most of the fuel saving and moves the payback outside any commercial range. "Accept a smaller unit" is, in practice, "build something that does not work financially".

The second is available in law but is rarely used by a small commercial or agricultural customer, for reasons of cost and unfamiliarity rather than lack of merit. The result is that the third option is taken by default.

ACDC's submission is that this is a consequence of the ambiguity rather than of any party's conduct. If the basis on which the permitted size is calculated were settled and published, most of these projects would either proceed at the correct size or be correctly sized at the outset, and the question of options after a reduction would rarely arise.

6. **[Distribution facility owners only]** What is your rationale or threshold for when to provide updates to customers on the status of their microgeneration projects? Please explain with reference to the factors and circumstances that may be considered.

Click or tap here to enter text.

a. Is providing customers with more frequent status updates a feasible and helpful option in general? Please explain, including any different considerations for small and large microgeneration projects.

Yes, and in our members' view the cost of providing them is lower than the cost of not providing them. Most requests owners currently field are status enquiries prompted by silence; a short scheduled update displaces several of them.

For small units, a brief notification at each phase transition is sufficient. For large units, where review periods are long and customer expenditure is committed earlier, the value of scheduled updates is greater and ACDC would support a defined maximum interval between contacts. In both cases the content that matters is short: what phase the project is in, what the owner is waiting for, and what the customer needs to do next.

General

1. **[Customers only]** Has any salesperson or company attempted to sell you or a member of your household a solar microgeneration system, especially door-to-door? If yes, please briefly describe your experience.

Click or tap here to enter text.

2. **[Distribution facility owners only]** Do you have the necessary information and tools to (a) monitor and (b) manage existing microgeneration generating units that may be out of

compliance with the *Micro-generation Regulation* (likely due to consistent generation in excess of annual consumption)? If not, please explain what you would require to do so.

Click or tap here to enter text.

3. If there is any other microgeneration-related information that you feel is important for the AUC to know, please briefly describe it here.

ACDC's submission is that Alberta's microgeneration framework accommodates cogeneration in law but not yet in practice, and that the gap can be closed by two clarifications that require no change of policy.

1. Confirm how the sizing test applies to a cogeneration unit.

Section 1(1)(h)(ii) of the Micro-generation Regulation requires that a unit be intended to meet all or a portion of "the customer's total annual energy consumption"; Section 2 of Rule 024 uses the same phrase. Where the Regulation means electricity it says "electric energy", as it does in subclauses (i) and (iv) of the same definition. In the sizing test it does not. Section 1(1)(l)(ii)(B) confirms the point from the other direction: it qualifies a unit by reference to "the total energy produced from the simultaneous generation of electric energy and production of thermal energy from the same fuel source". The Regulation expressly contemplates cogeneration and expressly counts recovered thermal energy as energy.

ACDC asks the Commission to confirm that for a unit which simultaneously generates electric energy and produces useful thermal energy from the same fuel source, the customer's total annual energy consumption includes both the electrical energy and the thermal energy consumed at the customer's site, with thermal energy converted at 277.78 kWh per gigajoule — the standard conversion, adopted so that both sides calculate the same figure.

ACDC also asks the Commission to confirm that sizing is assessed on the site's capacity as well as its annual energy. A unit runs against the site's real load, not its average one, and the site's service and transformer are sized in kVA. Section 1(1)(h)(ii) permits a unit to meet all of the customer's total annual energy consumption and not merely a portion of it, and a unit confined to an average annual figure cannot deliver that. Because an mCHP unit is available up to 8,760 hours a year, it should be assessed as base load rather than as an intermittent resource, and its permitted size should be capable of covering 100 per cent of the site's electrical requirement on three factors together: annual consumption in kWh, peak demand in kVA, and metered gas consumption in gigajoules converted at 277.78 kWh per gigajoule.

This affects no other technology. For solar photovoltaic, wind and every other single-output source, the site's electrical consumption remains the operative figure and nothing changes. It resolves the ambiguity only where the ambiguity exists.

2. Confirm that inverter-based requirements do not apply to units that produce AC directly.

An mCHP unit is an engine or turbine driving a synchronous or induction generator. It produces alternating current at the generator terminals, at grid voltage and frequency. It contains no photovoltaic array, no battery, no DC bus and no inverter. The proposed Section 1(d) of Rule 024 defines an inverter as a device that converts DC electricity into AC electricity; ACDC supports that definition and asks the Commission to draw the consequence from it.

Members have been directed by distribution facility owners to rectify the AC output of such a machine to DC and re-invert it through inverter equipment of the type used for solar photovoltaic installations. The direction has no engineering basis. It adds capital cost and permanent conversion losses to output that is already at grid voltage and frequency, inserts an additional failure point in series with the generation, and removes the fault current contribution and rotating inertia that a directly connected synchronous machine provides to the distribution system. Its origin is procedural: the owner's microgeneration procedure was written around inverter-based solar and has no category for a rotating machine.

ACDC asks the Commission to state that requirements framed around inverters apply only to units containing an inverter as defined in Section 1(d), and that units producing alternating current directly are subject to the interconnection protection, anti-islanding relaying, synchronizing and protection co-ordination requirements applicable to directly connected rotating machines. Our members are ready to meet those requirements in full.

3. A related point on scope, offered for completeness.

The thermal side of a cogeneration unit — heat exchangers, circulating pumps, storage, controls and the piping serving the building — is not connected to the interconnected electric system, to any thermal or district heating grid, or to any facility of the distribution facility owner. It is behind the customer's meter and serves that site's heating, hot water and process loads only, and it is regulated under the Safety Codes Act and the applicable mechanical, boiler and gas codes. It has no effect on the distribution system and cannot have one.

ACDC raises this because the site's thermal energy consumption is central to the sizing question above, and the two should not be confused. The site's thermal consumption is a measure of what the customer consumes, and it belongs in the sizing calculation. The thermal equipment itself is outside the connection process altogether, and neither its review nor its cost belongs in an application respecting connection to the interconnected electric system.

Why this matters to Alberta.

A cogeneration unit sized to a site's actual heat load displaces boiler fuel and grid electricity simultaneously from a single fuel input. The Micro-generation Regulation already recognizes the resulting efficiency, in the cogeneration limb of the greenhouse gas intensity test at Section 1(1)(l)(ii)(B). The technology is proven, the equipment is commercially available, and the host sites — greenhouses, food processors, care facilities, hotels, recreation centres and small industrial plants — exist in every part of the province.

What is missing is not policy. It is two sentences of clarification, so that a proponent and a distribution facility owner reach the same answer on the same facts. ACDC would welcome the opportunity to provide further technical detail, worked sizing examples or interconnection references to Commission staff, and thanks the Commission for extending the engagement period and for the opportunity to comment.