Consequential Electricity Sector Emissions Impacts

Summary of Public Consultation Feedback

1 Introduction

The Greenhouse Gas Protocol's public consultation on Consequential Electricity-Sector Emissions Impacts was conducted to gather stakeholder feedback on methods for quantifying the consequential greenhouse gas impacts of electricity-sector actions. The consultation ran from October 20, 2025 to January 31, 2026, as part of the broader update to GHG Protocol's corporate suite of standards and is intended specifically to inform the Actions and Market Instruments (AMI) workstream as it develops sector-agnostic guidance for reporting the emissions impacts of actions.

The consultation solicited input across four technical areas explored by the Scope 2 Technical Working Group's Consequential Subgroup:

- the proposed formula for quantifying emissions impacts from electricity projects (including the treatment of primary versus secondary effects and reporting period);
- the treatment of additionality, covering which tests should be required, optional, or excluded and whether rigor should vary by region or claim type;
- marginal emission rate methodologies for both operating margin and build margin calculations, along with appropriate spatial and temporal granularity; and
- approaches for weighting operating margin against build margin impacts.

Together, these questions were designed to elicit actionable feedback on which approaches stakeholders consider most appropriate, feasible, and rigorous for future GHG Protocol guidance. Outputs from this consultation will be incorporated into AMI's ongoing work on reporting the emissions impacts of actions.

The consultation drew 185 valid responses. The large majority were submitted on behalf of an organization (163 responses, 88%), with the remaining (22 responses, 12%) submitted by individuals.

By organization type, companies were the single largest group (60 responses, 32%), followed by consultants supporting organizations with GHG inventories or strategies (27 responses, 15%), non-profit/NGO/civil society organizations (21 responses, 11%), industry groups (17 responses, 9%), and energy suppliers, retailers, or utilities (16 responses, 9%). The remainder spanned academia and research (11 responses, 6%), data, analytics, or software providers (7 responses, 4%), financial institutions (5 responses, 3%), GHG accounting/reporting programs (3 responses, 2%), government institutions (3 responses, 2%), certificate registries (2 responses, 1%), and verification providers (1 response, <1%), alongside 12 respondents who selected "Other."

Geographically, the respondent pool was heavily concentrated in Northern America, which accounted for 109 responses (59%), driven overwhelmingly by the United States (104 responses, 56%). Europe was the second-largest region with 33 responses (18%), followed by Eastern Asia (17 responses, 9%), Latin America and the Caribbean (7 responses, 4%), South-eastern Asia (6 responses, 3%), and Oceania and Northern Africa (5 responses each, 3%). Southern Asia, Sub-Saharan Africa, and Western Asia were each represented by a single respondent.

Note/disclaimer: AI tools were used to assist with summarizing and analyzing feedback submitted through the Scope 2 public consultation. Personally identifiable information (PII) was removed from the data prior to AI-assisted review. AI outputs were used to support thematic analysis and synthesis only. Experts verified all the labels and made final decisions on which themes to include. GHG Protocol is responsible for final analysis and synthesis.

2 Quantifying Emissions Impacts from Electricity Projects

2.1 General Feedback on Consequential Methods

Question 18 asked respondents: “What potential benefits, challenges, or unintended consequences do you foresee with developing and using consequential accounting methods for electricity-sector actions?”. The responses within each section below are sorted by decreasing number of mentions[1].

Benefits of consequential accounting approaches for electricity

Many respondents noted that consequential accounting approaches are useful in directing investment toward high-impact actions. These respondents argued that consequential data gives a clearer signal for directing capital to the actions/locations which matter the most because the method is designed to account for specific changes resulting from actions and decisions. Many of these respondents also noted that consequential accounting can serve an important complementary purpose alongside attributional accounting, and therefore should not be designed to replace attributional methods.

Many respondents pointed to consequential accounting as an integrity improvement, and highlighted its role in combatting greenwashing. These respondents argued that consequential accounting is the only method designed to account for real emission reductions, rather than contractual claims, which may not be aligned with physical emissions changes.

Some respondents noted that consequential accounting is better suited to recognize certain technologies like battery storage and demand response, which attributional methods can only represent as a net emissions increase.

A few respondents argued that consequential accounting is a more equitable global methodology. These respondents noted that under-invested regions often offer the biggest potential emissions impact but are overlooked because they are harder to invest in. Respondents stated that since consequential accounting may not depend as much on the maturity of the reporting infrastructure, it may allow for capital to more easily follow climate impact.

Challenges of consequential accounting approaches for electricity

Many respondents mentioned data quality, methodological complexity, and cost burden as potential challenges of the approach. Respondents noted that the availability of higher frequency locational marginal emission rates, including both short and long-run emission rates, paired with the internal admin burden for smaller reporters, increases cost and reporting burden for many companies. In addition, respondents noted that due to the complexity of the approach, different methodologies can often generate significantly different results, undermining comparability.

Many respondents pointed to specific methodological topics as potential areas of concern with the method. Respondents highlighted additionality as a key challenge, and noted that these tests must be balanced appropriately to avoid over-crediting while still incentivizing enough investment. Other respondents argued that induced emissions should also be quantified alongside avoided emissions, and that this netting approach is necessary to communicate the full emissions impact of an organization’s electricity-related actions. Finally, respondents stressed that auditability is a key concern with any approach that uses a counterfactual baseline, and that strict rules must be in place to support verification.

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[1] In this summary report, when frequencies are mentioned, the following applies:
Almost all = all except a very small minority
Most = a large majority, with more than a few exceptions
Many = a small majority, or large minority
Some = a small minority, but more than a few
A few = a very small minority

Some respondents argued that specific purposes and use cases must be established first, to ensure the right methodological decisions are made. For example, whether the method is used for internal decision-making or offset-like claims has implications for additionality requirements or audit restrictions. In addition, respondents raised the question of how to account for crediting actions between purchasers and generators, where there could be overlapping claims.

Unintended Consequences

Respondents raised several unintended consequences of applying consequential accounting to electricity sector actions. Most frequently mentioned was the risk of double counting: without clear separation, consequential results could be confused with verified inventory reductions. A few respondents added that multiple parties (utilities, buyers, aggregators, storage owners) could end up claiming credit for the same avoided emissions without clear attribution rules. Respondents also raised an integrity risk: without strong additionality and disclosure safeguards, reported avoided emissions could be overstated, and a few respondents noted the risk of credibility challenges, as experienced in the voluntary carbon offset markets (overstated claims, disputed baselines, and public skepticism).

Another frequently raised concern was that this method could weaken the existing scope 2 incentive for new renewables, removing the driver behind long-term PPAs and slowing new clean energy build. A few respondents pointed to two opposite risks for regions: investment could concentrate only in high-emission ("dirty grid") areas, since impact looks higher there, leaving existing clean infrastructure under-invested; or regions without good emissions data could struggle to prove their claims as easily.

2.2 Feedback on Proposed Subgroup Formula

Question 19 asked respondents: "Is the proposed Scope 2 TWG subgroup formula appropriate for quantifying emissions impacts from electricity projects?"

The formula for quantifying emissions impacts of electricity projects, described below, uses electricity consumption multiplied by marginal emission rates.

$$Emissions\ Impact_t = \sum_{i \in P_y} (MWh_i \times MER_i)$$

P_y = set of all procurement transactions in the reporting year

MWh_i = megawatt hours procured in transaction i

MER_i = marginal emission rate applicable to the grid region, time, and conditions of transaction i

Stated as a formula using hourly procurement and marginal emission rates:

$$Emissions\ Impact_i = \sum_{t=1}^{8760} \left(MWh_t^{procured} \times MER_t\right)$$

t = hour of the year

$MWh_t^{procured}$ = electricity procured during hour t

MER_t = marginal emission rate for the relevant grid/zone in hour t

133 respondents provided an answer to this question.

Table 1: Responses to Question 19

Whether Scope 2 Subgroup Approach is Appropriate	Count	% Respondents
Yes	49	37%
No	84	63%

Many non-supportive respondents argued the new approach imposes an excessive data burden, requiring hourly marginal-rate data for unclear benefit. Respondents also argued that the approach of only assessing avoided emissions from electricity project development is one-sided, and departs from the TWG subgroup's complete proposal, which also included an assessment of emissions "induced" by electricity consumption, and proposed netting the two values. Some respondents added that this approach can specifically overstate or misstate the impact of batteries and storage. Some respondents noted that it is not clear whether the approach covers electricity procurement, electricity projects, or all electricity-related actions, and how effects are bounded.

Many supportive respondents said time- and location-varying marginal emission rates capture actual grid behaviour better than annual averages and that the counterfactual baseline and primary/secondary split are conceptually correct. Many respondents agree with the proposal, but only if other conditions are fulfilled (clear boundaries, data-quality thresholds, additionality, linkage to Scope 2).

2.3 Feedback on Design Elements of Emissions Impact Quantification Approach

Question 21 asked respondents: "Should the quantification of emissions impacts from electricity projects consider secondary effects in addition to primary effects?"

110 respondents provided an answer to this question.

Table 2: Responses to Question 21

Whether Emissions Impact Approaches Should Consider Secondary Effects	Count	% Respondents
Yes	57	52%
No	53	48%

Many respondents who argued for including secondary effects noted that fuel extraction, construction, and decommissioning emissions should be captured, especially where they are a significant share of a technology's footprint. Some respondents argued that "build-margin" impacts, which capture long term effects on construction or decommissioning of power plants, should be included as a default. According to existing guidelines on quantifying emission impacts from electricity projects, build margin effects would be considered primary effects. Some respondents also argued that effects with established clear methods for quantification, such as marginal emission rates, should be required, whereas effects that rely on significant assumptions (such as life-cycle assessments) can remain optional.

Some respondents that argued against including secondary effects noted that this requirement would add complexity and uncertainty due to hard-to-verify assumptions. These respondents also noted that data is not consistently available across regions or technologies to perform these assessments, undermining comparability. Some respondents cautioned against double counting of secondary effects which might be already reported in scope 3 or life cycle frameworks. A few respondents consider secondary effects to be usually immaterial, and therefore not necessary to include in a consequential accounting framework, at least for the electricity sector.

The conditions participants specified as prerequisites for including secondary effects in the quantification of emissions impact:

- Using marginal emission factors, dispatch/scenario modelling, or life-cycle assessment (LCA) in the quantification.
- Secondary effect should pass a materiality threshold of a primary effect (e.g. 5%) to be included.
- Since batteries/storage act as both electricity consumer and generator, some respondents noted that emissions impacts of charging and discharging of storage would require its own separate accounting treatment.

Question 24 asked respondents: "Should the emissions impacts of electricity projects be calculated and reported each reporting year, or should the emissions impacts for the entire lifetime of a project be reported once at the outset of the project?"

103 respondents provided an answer to this question.

Table 3: Responses to Question 24

Whether to Report Annually, or Once at the Outset of a Project	Count	% Respondents
Reported each year	81	79%
Reported once for the lifetime of the project	22	21%

Most respondents who supported annual reporting said emissions impacts should be calculated and reported each reporting year because they prefer the metric to reflect actual realized results rather than initially projected values. Most respondents noted that grid conditions (marginal emission rates, dispatch patterns, fuel mix, and system evolution) change from year to year, so estimated impacts may become outdated as the grid changes. Further, lifetime reporting requires more modelling assumptions than annual reporting, negatively impacting comparability among reported values. Most respondents also pointed out that annual reporting is consistent with existing GHG accounting frameworks which supports implementation and aligns the reporting cadence with existing practices.

Many respondents favoring annual reporting also added that annual, ex-post reporting is easier to verify because it is based on historical data, rather than forecasts of grid evolution, fuel prices, and policy that are unverifiable decades out. A smaller group raised a different concern: if a project helps clean up the grid, due to the annual recalculation of baseline that progress will look smaller over time because the counterfactual scenario "improves". To avoid this, several suggested fixing the baseline once at the start of the project, while still reporting results every year.

Respondents who preferred reporting impacts once for the lifetime of the project noted the high administrative costs associated with annual reporting, and drew parallels to scope 3 category 11 reporting (emissions associated with the use of sold products), which adopts an upfront lifetime accounting approach. Respondents also noted that lifetime reporting supports investment predictability, which is especially important for long-term contracts that require a clear vision of the project's climate impact. Annual reporting can result in significant changes year to year, and may threaten the avoided emissions value of a long-term contract as grid conditions change. A few respondents proposed dual reporting: an ex-ante lifetime estimate for investment decisions, updated or supplemented by ex-post annual figures once actual performance data exists.

3 Treatment of Additionality

This section contained questions on tests for assessing additionality of electricity projects. Consultation feedback will further inform AMI TWG discussions on additionality criteria.

3.1 General Feedback on Additionality Tests

Question 26 asked respondents: "For each of the provided additionality tests, indicate which tests should be included (required or optional) in a framework designed to assess additionality for renewable energy projects?

For these questions, "required" indicates a mandatory test, such that all projects must pass the test in question to be eligible. "Optional" indicates that a test can be used to demonstrate additionality but is not mandatory. For optional tests, projects have the choice for which tests they use to demonstrate additionality."

Respondents were able to provide answers to as many additionality tests as they wanted.

Table 4: Responses to Question 26

Additionality Test	Required	Optional	Not Required
Regulatory	69 (64%)	22 (20%)	17 (16%)
Timing	52 (49%)	31 (29%)	23 (22%)
Contractual/tenor	24 (24%)	41 (40%)	37 (36%)
Common practice	23 (22%)	33 (32%)	47 (46%)
Financial analysis	18 (17%)	58 (54%)	31 (29%)
Positive list	18 (17%)	57 (54%)	30 (29%)
Barrier	15 (15%)	46 (46%)	40 (40%)
Performance standard	14 (14%)	38 (38%)	49 (49%)
First-of-its-kind	10 (10%)	36 (36%)	53 (54%)

Question 27 asked respondents: "For the additionality tests you selected as required or optional, please provide commentary detailing why each should be included."

97 respondents gave open-text rationale explaining why tests they marked Required or Optional should be included. The table below is organized by test, showing the core rationale respondents gave.

Table 5: Responses to Question 27

Test	Core rationale
Regulatory test	Most respondents agreed that if a project is already mandated by law or policy it cannot be considered additional. Caution must be exercised regarding project-specific mandates, not broad policy goals (e.g., national net-zero targets or EU-wide ETS should not disqualify all projects in that jurisdiction).
Timing test	The respondents supported the timing test because it establishes causality between the incentive (contract/PPA) and the final investment decision (FID). If the incentive date precedes the FID date, it means the incentive was a factor in the financing decision. Many respondents flagged that terms like "planned" or "under construction" don't have a universal definition, and the line can be drawn in different ways, making the test open to dispute. This might unfairly exclude repowering projects, distressed-project rescues, or secondary PPA transfers.
Contractual/tenor test	A minimum contract length (5-10+ years commonly cited) is seen as strong, objective evidence that a buyer's commitment gave a project the revenue certainty needed for financing. Respondent's criticism related to the rigid thresholds which could disqualify legitimate non-standard structures (outright purchases, tolling, short high-value contracts).
Common practice test	A large share of respondents opposed this test, arguing it ignores marginal grid physics – a technology can be common practice regionally yet still displace marginal fossil generation at a specific time and location.
Positive list	The test is mostly supported under conditions that it is optional and regularly updated as technologies mature. Its main strength is that it functions as a pre-approved list of eligible project types/structures, reducing administrative burden and transaction costs.
Financial analysis test	Many respondents prefer this test to be optional; however, it is viewed as one of the strongest tests since it shows whether the incentive materially improved project economics (IRR/NPV) or closed a financing gap. Subjectivity in assumptions, reliance on confidential data, and high verification burden were named as practical problems.
Barrier test	If the financial data is unavailable, this test can show whether other barriers (e.g. regulatory, technical, institutional) were overcome. Many respondents noted it might be too subjective and inconsistent to apply globally and preferred it to be optional.
Performance standard	Respondents noted this is useful in cases where robust baselines exist, since it sets a quantifiable benchmark a project must beat to demonstrate additionality (e.g., an emissions-intensity or efficiency threshold). However, most respondents recognize that baselines vary too much by region and technology to apply as a universal requirement.
First-of-its-kind test	The least-supported test overall: most respondents see it as too narrow, since it stops applying once a technology matures, and offers little beyond what other tests already capture.

Overall, the survey showed that regulatory and timing tests are the most favored to be included as mandatory. The next most supported tests were positive list and financial analysis, however they came with some conditions and warnings on the verification burden. The remaining tests were proposed to be optional or not required. A small minority of respondents opposed requiring any additionality tests at all.

Feasibility of additionality tests

Question 28 asked respondents: "For each of the provided additionality tests, please indicate which tests are feasible to implement."

Respondents were able to select multiple additionality tests.

Table 6: Responses to Question 28

Which Additionality Tests Are Feasible	Count	% Respondents
Regulatory	80	82%
Timing	72	74%
Positive list	58	59%
Contractual/tenor	47	48%
Financial analysis test	44	45%
Performance standard	42	43%
Common practice	39	40%
First-of-its-kind	35	36%
Barrier	30	31%
None (no tests are feasible)	10	10%

Regulatory and timing tests were rated the most feasible tests and were most often proposed as mandatory. Positive list tests were also described as feasible by a majority of respondents, but were recommended to be optional.

Roughly 80 respondents gave open-text feedback on feasibility, rating regulatory and timing tests as the most verifiable and least burdensome, and financial analysis as the most difficult due to its reliance on confidential financial data that companies are unwilling or unable to disclose.

Some respondents noted that financial analysis, barrier, and common practice tests are the hardest to apply consistently due to high level of subjectivism regarding the counterfactual scenario. A common sentiment among respondents was that feasibility depends heavily on region, market maturity, and data availability. Respondents noted that tests that are straightforward in mature markets (US ISOs/RTOs, EU) may be impractical in data-scarce markets.

Further additionality tests

Question 30 asked respondents: "Please list any additionality tests not already included here that should be considered as part of an additionality framework for renewable energy projects. Please explain why each test should be considered)."

42 respondents provided an answer to this question, about 24 of them proposed at least one additional additionality test not already listed in the survey; the remaining respondents either did not propose further tests or explicitly said the existing nine are sufficient.

The distinct proposals cluster around a small number of shared themes, each of them was mentioned by two to five respondents only (the table displays most-mentioned first).

Table 7: Responses to Question 30

Proposed test	Short description
System/grid-value or marginal-displacement test	Assesses whether a project measurably reduces emissions at the margin, contributes to system needs, or influences future capacity decisions – linking additionality to actual system impact rather than project novelty.
Grid congestion / curtailment / deliverability test	Checks whether a project can physically deliver power without persistent congestion or curtailment; high-curtailment or constrained projects may have lower real-world emissions impact than assumed.
Durability / permanence test	Evaluates whether emission reductions are long-lasting rather than temporary or reversible (e.g., due to cap-and-trade allowance leakage, REC swapping, or short-term contracts).
Policy interaction / "surplus" test	Confirms a project's impact goes beyond what is already delivered or guaranteed by binding policy (e.g., RPS, ETS caps), avoiding double counting with regulatory obligations.
Dynamic baselining test (storage/behavioural)	Compares an asset's observed, emissions-optimized dispatch (e.g., a battery) against a modelled revenue-maximizing counterfactual, to recognize "behavioral" additionality in existing flexible assets, not just new builds.
Incrementality test (non-causal, action-based)	Assesses whether a discrete action (new build, uprate, repowering, dispatch change) represents a material change relative to a prior state, without needing to prove who caused it – an alternative to causal timing tests.
REC market-clearing / price-ratio test	Checks that RECs are sold at a meaningfully positive price (e.g., REC price ≥~15% of the average 24-hour electricity price) to confirm the market is functioning and the REC carries real value.

In addition to these tests, some respondents proposed additional quality criteria that should accompany additionality tests. These quality criteria include:

- Verification/transparency requirements – requires that additionality claims and baseline/counterfactual assumptions be independently auditable, transparently documented, and reproducible.
- Minimum project scale/capacity – an optional, region-specific minimum capacity threshold (e.g., 50MW for U.S. solar) intended to ensure a project couldn't have been self-financed by the developer alone.

3.2 Additional Design Considerations

Question 31 asked respondents: "Should regional differences be considered in additionality tests (e.g. different combinations of additionality tests would be relevant or appropriate for different regions)?"

101 respondents provided an answer to the question.

Table 8: Responses to Question 31

Whether to Consider Regional Differences	Count	% Respondents
Yes	40	40%

Unsure, depends on the details	32	32%
No	29	29%

Among respondents who favored consideration of regional differences, most stated that the additionality test choice should depend on market maturity and policy context. In mature markets, reporters should be subject to stricter financial, common-practice, or timing tests, while in data-scare and developing markets reporters should be able to choose from more flexible regulatory, barrier, or positive-list tests. Respondents pointed to specific markets, including Brazil, Japan, China, U.S. hydropower, Ireland, and Germany as evidence for these recommendations.

Some respondents recommended addressing this issue through optional tiers of tests, letting organizations select feasible tests while still meeting an overall standard.

Among respondents who answered "no" or "unsure", many made the case that additionality tests should remain standardized worldwide for comparability, with regional differences reflected only in the data used to apply them (e.g., materiality threshold), not in which tests apply. They referred to added complexity and burden as risks of a region-specific approach.

Question 33 asked respondents: "Should the level of rigor in additionality tests be applied differently depending on the type of claim an organization wants to make? (e.g. association vs. causal claim)."

78 respondents provided an answer to the question.

Table 9: Responses to Question 33

Whether Rigor Should be Applied Differently	Count	% Respondents
Yes	43	55%
No	35	45%

Question 34 asked those who responded "yes" to explain their rationale, therefore, the below summary focuses on perspectives for those responding "yes". Despite that, some respondents who responded "no" also provided feedback to this question.

Among respondents who supported differentiated rigor in additionality tests, many suggested a tiered approach, where lighter-touch tests (such as regulatory and timing tests) should suffice for association-type claims (e.g., "we support renewable energy," "we procured clean electricity in this region"), while causal claims that assert a specific avoided-emissions outcome (e.g., "our procurement caused X tonnes of avoided emissions") should require the fuller range of tests (financial analysis, barrier, common practice, and/or contractual/tenor). The recurring logic among these respondents is that stronger claims require stronger proof, and that rigor should scale with claim strength to reduce greenwashing risk, avoid unnecessary burden on modest claims, and keep verification effort proportionate to materiality.

Some respondents proposed a three-tier spectrum for EAC procurement: unbundled EACs with no buyer influence, "contributing" EACs where a buyer partly provides funds but doesn't single-handedly enable a project, and "causal" or "purchaser-caused" EACs that meet defined thresholds (e.g., 70–80% of project financing, a 10+ year contract term, and/or a minimum capacity commitment). A few respondents took an even stricter view: association-type claims should never use avoided-emissions or "impact" language; only additionality-proved projects can claim a real-world emissions outcome.

Finally, a few respondents supported tiering for practical reasons: requiring full causal-level rigor for every claim would raise transaction costs and risk excluding smaller buyers from participating in voluntary procurement.

A few respondents opposed tiering altogether, arguing for one single, non-negotiable rigorous standard regardless of claim type. These respondents stated that differentiated rigor creates a two-tier system that could be gamed, undermines comparability, and allows the claim to dictate how much proof is required, rather than the quality of existing data.

4 Marginal Emission Rates

4.1 Operating Margin

Quantitative Feedback on Questions 35 and 36

Question 35 asked respondents: "Which methodology or methodologies are appropriate for quantifying the operating margin emissions impacts of renewable energy projects? (select all that apply)"

69 respondents provided an answer to question 35.

Table 10: Responses to Question 35

Methodology	Count	% Respondents
SCED – locational	48	70%
Statistical	44	64%
SCED – fuel on the margin	40	58%
Scenario modeling	26	38%
Heat-rate/LMP	23	33%
Capacity factor based	20	29%
Difference-based	18	26%
None	7	10%

Question 36 asked respondents: "Which methodology or methodologies for quantifying the operating margin emissions impacts of renewable energy projects are not appropriate? (select all that apply)"

57 respondents provided an answer to question 36.

Table 11: Responses to Question 36

Methodology	Count	% Respondents
Capacity factor based	31	54%
Difference-based	28	49%
Scenario modeling	25	44%
Heat-rate/LMP	24	42%
SCED – locational	12	21%
SCED – fuel on the margin	11	19%
Statistical	10	18%
None	9	16%

Comparing appropriate and not appropriate feedback, the three methodologies with a high net favorability rating from respondents were SCED – locational, statistical, and SCED – fuel on the margin. Scenario modeling and heat-rate/LMP received a neutral net favorability, and capacity factor based and difference-based received a net negative favorability.

Summary of Feedback on Operating Margin Methodologies

Respondents were given the opportunity to provide open-ended feedback on which methodologies they believe are appropriate or not appropriate for avoided emissions quantification.

Preference for empirical approaches

Many respondents expressed the view that methodologies based on observable, empirical dispatch data are preferrable over those that use a modeled approach. For this reason, SCED – locational received the most comments in support, with statistical and SCED – fuel on the margin also receiving significant support. SCED – locational was viewed more positively than SCED – fuel on the margin; respondents generally argued that SCED – fuel on the margin can be inappropriate when applied across a large region, as different generators are on the margin in different nodes simultaneously. The statistical approach was viewed as a positive fallback in cases where SCED – locational is not available due to the absence of public dispatch data.

Heat-rate/LMP and scenario modeling approaches are viewed by respondents as reasonable proxies when other methods are not possible, but are not ideal for routine accounting. Regarding heat-rate/LMP approaches specifically, critical respondents noted that the assumption that price reflects the marginal unit's fuel cost breaks down whenever multiple fuel types can be on the margin, which they claim is possible on most grids.

Capacity factor based and difference-based approaches were viewed the most critically by respondents, with the most common sentiment being that they are overly coarse, and may not accurately capture the intention of operating margin emission factors.

Skeptical views of marginal accounting approaches

A few respondents noted general concerns about the application of marginal accounting approaches, largely focusing on the accuracy limitations of the methodologies, the applicability to corporate reporting, and fundamental disagreement that marginal power plants even exist. These respondents believe that marginal accounting approaches can be useful for research, but do not have a role as a corporate-level accounting measure.

Requests for further development

Some respondents took the opportunity to request that GHGP wait for empirical benchmarking of these methodologies before deciding on an approach. These respondents also called for more engagement with the academic community on the topic, and to open further public consultation on this matter specifically, given its complexity.

Lastly, a few respondents specifically mentioned energy storage as an area that requires further thinking and development. These respondents noted that determining the marginal emissions associated with battery discharge is difficult or even theoretically impossible. Some of these respondents call for more consideration of how to accurately quantify the marginal emissions of dispatch, while others believe storage should be excluded entirely from the set of marginal generators.

4.2 Build Margin

Quantitative Feedback on Questions 38 and 39

Question 38 asked respondents: "Which methodology or methodologies are appropriate for quantifying the build margin emissions impacts of renewable energy projects? (select all that apply)".

69 respondents provided an answer to question 38.

Table 12: Responses to Question 38

Methodology	Count	% Respondents
Recent capacity additions	48	70%
Capacity expansion modeling	30	44%
Policy scenario	26	38%
Average emission rate	17	25%
None	7	10%

Question 39 asked respondents: "Which methodology or methodologies for quantifying the build margin emissions impacts of renewable energy projects are not appropriate? (select all that apply)"

58 respondents provided an answer to question 39.

Table 13: Responses to Question 39

Methodology	Count	% Respondents
Average emission rate	38	66%
Policy scenario	29	50%
Capacity expansion modeling	27	47%
Recent capacity additions	11	19%
None	5	9%

Comparing appropriate and not appropriate ratings, recent capacity additions was the clear favorite among respondents. Capacity expansion modeling and policy scenario received roughly neutral favorability, while average emission rate was clearly not supported by respondents.

Summary of Feedback on Build Margin Methodologies

Preference for empirical approaches

Similar to the feedback on operating margin emission rates, many respondents expressed the view that build margin emission factors should be derived from historical, observed grid behavior. As the only method of the four that uses historical data, the recent capacity additions approach was viewed most favorably. Supporters of this approach stressed that it is the most transparent and auditable methodology, and therefore best suited for corporate reporting.

A few respondents noted limitations of the recent capacity additions approach, citing potential weakness in rapidly transforming grids, and the fact that the approach only considers capacity additions, and not accelerated retirements.

Capacity expansion modeling and policy scenario methodologies received similar feedback from respondents. Some respondents noted that policies are often the main driver of generation capacity build out, and therefore methods that are based on modeled interpretation of policy can perform well in predicting how grids evolve. Other respondents argued that policy is a fundamentally unreliable signal, since policies change, and that this has negatively impacted the performance of these methodologies over time. Some respondents also noted that these two approaches are far less auditable than methods that rely on observable historical data.

Objection to using build margin rates for corporate reporting

A few respondents questioned the applicability of build margin rates for corporate reporting generally, citing the long term nature of these rates. These respondents suggested that build margin rates are useful for macro modeling, policy decisions, and long term strategic planning, but not for yearly corporate emission reporting.

Requests for further development

Respondents repeated their sentiments detailed in Section 4.1, suggesting that GHGP conduct further testing of these approaches.

4.3 Additional Design Considerations

How to assess model applicability

Question 41 asked respondents: "How could GHG Protocol assess these models' applicability to different types of projects? Factors that could affect applicability may include, but are not limited to, project size, shape, and capacity factor."

36 respondents provided substantive responses to the question.

Some respondents suggested a tiered approach, where model sophistication matches the likely system impact of the project in question. Small projects could only be required to use screening methodologies (recent capacity additions), while larger system-shaping projects would be required to use more sophisticated models like SCED-based or capacity expansion.

Other respondents argued for more consistency with model selection, and suggested instead tailoring the weighting between build and operating margin emission factors to align with project types. These respondents noted that companies using different models could negatively impact the accuracy of reported emission values and harm comparability.

Additional types of emission factors

Question 42 asked respondents: "What other types of emission rates or metrics may be appropriate for assessing the emissions impacts of projects?"

25 respondents provided substantive responses to the question.

Many of these respondents took the opportunity to highlight the value of also quantifying "induced emissions," or emissions caused by electricity consumption, not just avoided emissions from electricity projects. These respondents noted that focusing only on avoided emissions from electricity projects omits valuable information and decarbonization opportunities from load shifting of electricity consumption.

A few respondents raised long-run marginal emission rates as an alternative or complement to the operating/build margin structure. These respondents suggested LRMERs have shown promise for combining operating and build margin impacts, citing recent research on consequential emissions from EV charging, and proposed them as worth investigating.

Spatial granularity

Question 43 asked respondents: "What is the maximum appropriate level of spatial granularity for marginal emission rates?"

80 respondents provided an answer to question 43. Responses were roughly evenly distributed across four spatial granularities, with significant variability in the sizes of these regions. Zonal boundaries was the clear least preferred option among respondents.

Table 14: Responses to Question 43

Spatial Granularity	Count	% Respondents
Country	22	28%
Grid region	20	25%
Balancing area	15	19%
Zonal	3	4%
Nodal	20	25%

Some respondents who favored country as the maximum appropriate spatial granularity noted that country sizes differ significantly, and so for some countries the national boundary is an appropriate level of granularity. Other respondents who chose country argued in favor of feasibility and availability of data, pointing out that country level data is the most available globally.

Respondents who selected grid region and balancing area tended to argue that these represent a good middle ground, balancing feasibility and accuracy. These respondents argued that more granular data sets are not widely available, and that less granular data sets do not adequately capture regional differences.

Respondents who selected nodal granularity argued that intra-regional and intra-zonal transmission congestion causes marginal emission rates to vary significantly within these regions. These respondents argue that only nodal resolution reliably captures the generator that responds to load signals. Some of these respondents noted that a requirement to use nodal granularity should only apply in regions where the marginal data exists, and not be a universal global mandate.

Temporal granularity

Question 45 asked respondents: "What is the maximum appropriate level of temporal granularity for marginal emission rates?"

81 respondents provided an answer to the question. Responses were largely bi-modal, with the two most common answers (annual and hourly) receiving roughly the same number of votes. A slight majority (54%) of respondents selected hourly or sub-hourly as the maximum appropriate temporal granularity.

Table 15: Responses to Question 45

Temporal Granularity	Count	% Respondents
Annual	31	38%
Monthly	6	7%
Daily	0	0%
Hourly	30	37%
Sub-hourly	14	17%

Respondents who chose annual granularity expressed a wide variety of justifications. Some respondents argued that global availability of data and feasibility point in the direction of allowing annual granularity as the maximum resolution, though some of these respondents also pointed out that reporting organizations with access to more granular data should use it. A few respondents made a specific point related to build margin emission factors, arguing that hourly resolution is not necessary for build margin, as these rates convey long-term structural changes. A few respondents also argued that more granular does not always equate to more accurate.

Respondents who selected monthly granularity largely highlighted a balance between feasibility and accuracy. These respondents argued that monthly emission factors capture important seasonal variation, which makes them more accurate than annual emission factors, but are also easier to implement for reporting organizations than hourly emission factors.

Respondents who selected hourly or sub-hourly granularity generally argued that hourly resolution is important to capture diurnal and seasonal changes in emissions intensity of marginal generating units, and should therefore be the maximum appropriate granularity. Respondents who selected sub-hourly noted that grid dispatch occurs at 5- or 15-minute intervals, and therefore it is the technically correct granularity at which to measure marginal emission rates. A few of these respondents noted that renewables curtailment often lasts for very short periods of time (as little as 5 minutes), and therefore producing renewables at these times has zero consequential impact. In general, respondents who selected hourly or sub-hourly believe that more granular data is better, and organizations should use the most granular emission factor available to them.

5 Build and Operating Margin Weighting

5.1 Assessment of Weighting Approaches

Quantitative feedback on questions 47 and 49

Question 47 asked respondents: "Which, if any, of the included approaches for assigning build and operating margin weights for electricity projects are appropriate? (select all that apply)"

67 respondents provided an answer to the question, and were able to select multiple options.

Table 16: Responses to Question 47

Weighting Approach	Count	% Respondents
GHGP Guidelines	30	45%
UNFCCC CDM Tool07	19	28%
Default 0.5 build margin weight	16	24%
Intervention life cycle approaches	13	19%
Resource adequacy approaches	9	13%
None are appropriate	9	13%
Unsure	15	22%

Question 49 asked respondents: "Which, if any, of the included approaches for assigning build and operating margin weights for electricity projects are not feasible to implement? (select all that apply)"

57 respondents provided an answer to the question, and were able to select multiple options.

Table 17: Responses to Question 49

Weighting Approach	Count	% Respondents
Unsure	21	37%
All are feasible	16	28%
Resource adequacy approaches	17	30%
Intervention life cycle approaches	15	26%
UNFCCC CDM Tool07	10	18%
GHGP Guidelines	8	14%
Default 0.5 build margin weight	8	14%

Summary of feedback on weighting approaches

Respondents surfaced similar tensions around accuracy vs. feasibility in responses to questions on emission factor weighting, as in other sections of this consultation. Respondents who favored the default 0.5 build margin weighting approach argued that it is the most feasible, comparable, and consistent approach of the approaches presented. These respondents also argue that it is the most scalable approach, and will support the fastest adoption of emissions impact quantification. A subset of these respondents noted that further development and research of weighting approaches should be conducted, but that until there is a widely agreed upon approach, a default 0.5 weighting approach should be implemented.

Respondents who chose either the GHGP Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects (GHGP Guidelines) or UNFCCC approaches noted that these are the most established existing methodologies, and therefore should be the default, at least initially. Many of these respondents described these two methodologies as audit-tested, and therefore lower risk for GHGP to adopt in an emissions standard.

Respondents who selected either intervention life cycle or resource adequacy approaches largely put forth accuracy arguments. These respondents claim that the default 0.5 approach is arbitrary and obsolete, and fails to capture key dynamics of grid build out. A key argument for this group of respondents is that weighting should be viewed dynamically, mirroring how the grid works. Changes to electricity generation or consumption usually impact the operating margin initially, then transition to impacting the build margin as the grid reacts to the added generation or load.

On feasibility, respondents viewed the default 0.5 build margin approach and the two established methodologies (GHGP and UNFCCC) as most feasible. Generally, the other approaches were viewed as potentially more technically rigorous, but less feasible and scalable for a large portfolio of projects.

5.2 Other Approaches to Weighting Build and Operating Margin

Question 51 asked respondents: "Other than the approaches listed here, what approach could be used to assign build and operating margin weights for electricity projects?"

25 respondents provided substantive answers.

Time-varying or dynamic approaches

The largest group of respondents to this question proposed a form of dynamic weighting approach, where operating margin is more heavily weighted at the start of a project, transitioning to build margin being more heavily weighted over time. Some of these respondents proposed dynamic approaches to shifting these weights, based on real grid dynamics, while other respondents proposed pre-determined schedules based on the year from project start.

Dispatchability-based approaches

Another group of respondents proposed assigning weights based on the extent to which a project is dispatchable. Projects with high dispatchability, such as batteries or demand response, are assigned higher operating margin weights, whereas non-dispatchable projects like wind or solar get higher build margin weights.

Approaches based on grid condition

A few respondents suggested tying weights to tangible grid conditions for the appropriate grids. For example, a grid with surplus resources may be assigned a weight geared more toward operating margin, whereas a capacity-constrained grid may be assigned a weight geared more toward build margin.