Greenhouse Gas and Clean Energy Accounting Methodology Catalog

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This report is developed on behalf of the Western Energy Supply and Transmission Associates ("WEST Associates"), and in partnership with the Public Generating Pool (PGP) and other participating utilities. WEST Associates is comprised of a group of utilities operating in the Western U.S. with the mission of supporting sound energy, economic, and environmental policies based on excellence in science.[1] The PGP is a collective of generator-owners in the Pacific Northwest with the mission to educate, advocate, and collaborate in support of a reliable, affordable, and sustainable Western power system. This paper is informed by interviews with 15 utilities across the West, many of whom are members of the WEST Associates. WEST Associate utility interviewees include Arizona Electric Power Cooperative, Basin Electric Power Cooperative, Montana-Dakota Utilities, NV Energy, PacifiCorp, Platte River Power Authority, Portland General Electric, Salt River Project, and Tucson Electric Power; other interviewees include Avista Corporation, Eugene Water & Electric Board, Puget Sound Energy, Sacramento Municipal Utility District, Tacoma Power, and Xcel Energy.

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[1] WEST Associates' full membership includes: Arizona Electric Power Cooperative, Arizona Public Service, Basin Electric Power Cooperative, Montana Dakota Utilities, NV Energy, PacifiCorp, Platte River Power Authority, Portland General Electric, Public Service Company of New Mexico, Salt River Project, and Tucson Electric Power.

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Executive Summary

This study presents a catalog of Greenhouse Gas (GHG) and clean energy accounting methodologies in use across the Western U.S., inclusive of practices used under Renewable Portfolio Standards (RPS); energy supply mix disclosure programs; mandatory GHG reporting and reduction programs; and voluntary utility and end-use consumer reporting. This catalog aims to provide a representative, but not necessarily comprehensive, description of the GHG accounting practices in use today by utilities across the West, and is derived from a combination of detailed interviews with 15 participating utilities; program information provided by participating utilities; public documentation of required accounting practices under the various programs; and our own research.

MOTIVATION

This catalog aims first and foremost to contribute to information sharing amongst participating utilities regarding practices in use for the purposes of GHG accounting and compliance. We further provide an assessment of the range of alternative accounting approaches used under both mandatory and voluntary programs; identify potential inconsistencies and gray areas across the various programs; and provide a preliminary discussion of the potential implications for utilities, consumers, and for energy and decarbonization policies.

The utilities participating in this effort have expressed a variety of motivations and levels of urgency with respect to the need for clarity on GHG accounting practices. For utilities participating in limited or voluntary GHG accounting programs, there is a desire to understand common practice to help inform nascent or future reporting programs in response to inquiries from customers, lenders, policy makers, and company leadership. For utilities participating in ongoing regulatory rulemaking processes under mandatory state programs that have substantial regulatory and financial implications, there is an urgency to ensure that GHG obligations are clear and aligned with policy objectives so that utilities can effectively manage costs and mitigate transition risks on behalf of customers. Further, several utilities will need to introduce or revise their GHG accounting practices in the near term as more states introduce mandatory programs; in response to the Security and Exchange Commission (SEC) rulemaking expected in Fall 2023 that will expand and standardize requirements for climate-related risks including GHG emissions to investors; and in response to an ongoing effort to enhance the GHG Protocol upon which many government and private GHG reporting efforts have been developed.[2,3]

In the present study we aim to illuminate challenges and the potential for conflicts and convey common practice where possible to inform ongoing and future efforts. It is outside of our immediate scope to propose specific policy changes or a single set of best practices to resolve any identified concerns.

CATALOG OF PROGRAMS

Across the 15 utilities surveyed in this study, we have documented at least 56 distinct GHG and clean energy reporting or compliance regimes.[4] We categorize these regimes based on their general scope and purpose as follows:

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2 Securities and Exchange Commission (SEC), *17 CFR 210, 229, 232, 239, and 249* [Release Nos. 33-11042; 34-94478; File No. S7-10-22] RIN 3235-AM87, The Enhancement and Standardization of Climate-Related Disclosures for Investors Proposed Rule, 2022.

3 Greenhouse Gas Protocol, *Survey on Need and Scope for Updates or Additional Guidance*, 2022.

4 These programs include state, national, and voluntary programs. This program count does not consider representation from utilities in the Canadian portions of the Western Electricity Coordinating Council (WECC). Though the focus of this report is on implications for utilities in the Western Interconnect, a subset of the programs in question are associated with states in the Eastern Interconnect (Minnesota, Wisconsin, Michigan, North Dakota). We retain information about these programs in order to convey the full scope of regional differences in state policy and wholesale market participation models that have informed our utility interviews. The program count would be 48 if excluding states in the Eastern Interconnection.

- **RPS and Clean Energy Supply Targets:** These state mandates require that distribution utilities or load serving entities procure a certain minimum share of electric energy supply from renewable or clean energy supply. RPS compliance is demonstrated via the surrender of renewable energy certificates (RECs); plans to meet clean energy supply targets are typically demonstrated via Integrated Resource Plan (IRP) processes while compliance is subsequently demonstrated through after-the-fact compliance reporting.
- **Customer Energy Mix and GHG Intensity Disclosure Programs:** These mandatory reporting programs require utilities to disclose the owned and upstream resource mix reflected in fuel deliveries to end-use consumers. Most electricity supply mix disclosure programs require utilities to calculate and report their service area emissions rate as part of the same disclosure.
- **Mandatory GHG Emissions Reporting and Reduction Programs:** These programs require the mandatory reporting of GHG emissions, and in some cases impose mandatory requirements to reduce GHG emissions enforceable through a system of capping GHG emissions allowances or directly enforced limits. We further distinguish these programs among those relevant only to direct (Scope 1) emissions produced by fossil plants under the utility's ownership or control; from those that also cover indirect (Scope 2 and 3 upstream and downstream) emissions reporting.[5]
- **Voluntary Utility and End-Use Consumer GHG Reporting and Commitments:** Many utilities participate in voluntary reporting of GHG emissions or other sustainability metrics to consumers, investors, and the public; have made voluntary commitments to reduce GHG emissions or achieve other sustainability goals; and/or provide data or other supporting mechanisms to end-use consumers wishing to examine, disclose or reduce their own electricity-related GHG emissions.

We provide a brief summary of these programs in Table 1 below and describe them in greater detail in the body of this catalog. These programs vary greatly in terms of their underlying purpose, units of measure, regulatory oversight bodies, and enforcement mechanisms. Consequently, they also differ greatly in terms of the GHG accounting practices embedded within the rules or that may be subject to company interpretation. Further, in the case of RPS, clean energy standards (CES), and programs for disclosure of energy supply mix, the data and instruments related to these programs are also often used by customers or in other contexts to estimate or offset GHG emissions obligations even though these instruments were not originally designed for that purpose.

[5] As discussed further in the following background Section I, the concept of Scope 1, 2, and 3 emissions is laid out in the GHG Protocol and underpins many other GHG accounting frameworks. Scope 1 emissions are direct emissions from assets owned or controlled by a company. Scope 2 emissions are emissions associated with electricity consumed by a company. Scope 3 emissions encompass all other indirect emissions caused by the activities of a company, such as upstream emissions associated with purchased goods, or the downstream emissions linked to products sold. *See* World Business Council for Sustainable Development & World Resources Institute, *The GHG Protocol: A Corporate Accounting and Reporting Standard—Revised Edition*, Rev. 2004.

TABLE 1: GHG ACCOUNTING MECHANISMS AND FRAMEWORKS AFFECTING UTILITIES IN THE WEST

	Program Count	Program or State (Initial Year)
Renewable Portfolio Standards and Clean Energy Targets	**13 RPS programs**, including: • 2 Voluntary, 11 Mandatory **9 clean electricity targets;** 3 of these programs (CO, OR, WA) overlap with GHG reduction mandates below	RPS: AZ (2006), CA (2002), CO (2008), MI (2012), MN (2012), NV (2006), NM (2015), ND (voluntary, 2007), OR (2007), SD (voluntary, 2008), UT (2025), WA (2006), WI (2010) Clean Energy: CA (2018), CO (2019), MI (2020), MN (2023), NM (2019), NV (2019), OR (2021), WA (2019), WI (2019)
Customer Energy Mix and GHG Intensity Disclosure Programs	**9 programs**, including: • 6 programs that require emissions or emissions rates to be included (CA, MI, NV, OR, WA×2) • Many utilities, even in states without energy mix disclosure rules, report energy supply mix and emission rates that are available for retail customers	• California Power Source Disclosure Program (1997) • Colorado Component and Source Disclosure (1999) • Idaho (2007) • Michigan (2000) • Nevada (2001) • Oregon Electric Company and Electricity Service Suppliers Labeling (1999) • Washington Fuel Characteristics Disclosure (2000) • Washington Energy Independence Act (2006) • Washington GHG Content Calculation (2021)
Mandatory Greenhouse Gas Emissions Reporting and Reductions	**10 programs**, including: • 2 Federal (1 proposed), 8 state • Reporting scope: 2 direct Scope 1 (WA, US EPA); 8 Scopes 1-3 (CA×2, CO, OR×2, WA×2, US SEC) • 4 electricity sector (CO, OR×2, WA), 6 economy-wide (CA×2, WA×2, US×2) • 5 mandatory reduction targets (CA, CO, OR, WA×2); of which 2 include cap-and-trade programs (CA, WA)	• US EPA's Greenhouse Gas Reporting Program (2010) • SEC *The Enhancement and Standardization of Climate-Related Disclosures for Investors Proposed Rule* (2022) • California Mandatory Reporting Rule (2007) • California Cap and Trade (2011) • Colorado Greenhouse Gas Reporting and Emission Reduction Requirements (2020) • Oregon Greenhouse Gas Reporting Program (2015) • Oregon Clean Energy Targets (2021) • Washington Clean Air Act (1991) • Washington Clean Energy Transformation Act (2019) • Washington Climate Commitment Act (2023)
Voluntary Utility and End-Use Consumer Reporting & Commitments	**13 initiatives**, including: • 11 utility commitments • 2 additional GHG inventories **5 voluntary reporting frameworks** **Not quantified** but near universal experience with demand for accounting data from: contractual counterparties, cities, lenders, and end-use customers	**Utility commitments:** Avista, Eugene Water & Electric Board, Montana-Dakota Utilities, NV Energy (via Berkshire Hathaway), PacifiCorp (via Berkshire Hathaway), Platte River Power Authority, Portland General Electric, Puget Sound Energy, Salt River Project, Tucson Electric Power (both independently and via Fortis), Xcel Energy **Additional GHG inventories:** Basin Electric, Bonneville Power Administration **Voluntary reporting frameworks:** • Greenhouse Gas Protocol (2001) • The Climate Registry • Edison Electric Inventory/American Gas Association • CDP (formerly the Carbon Disclosure Project) • Global Reporting Initiative

IDENTIFIED THEMES

We identified several themes throughout the 15 utility interviews conducted for this study, each of which we discuss more fully throughout the body of this report:

- **Theme 1**: Due to the variety of state policies and voluntary protocols, there is no common, fit-for-purpose GHG emissions accounting methodology and data tracking system for the West.
- **Theme 2**: When accurate GHG emissions data are not available, a variety of accounting practices are used to approximate scope 2 and scope 3 emissions.

- **Theme 3**: The variety of accounting practices and data sources in use across the West can lead to inconsistencies or differences in estimated GHG emissions developed by different organizations and under different programs.
- **Theme 4:** Jurisdictional policy frameworks for GHG accounting are not consistent with the physical flow of electricity across broad geographies, electric system operational constraints, and current market structures.
- **Theme 5**: More accurate emissions rates associated with “unspecified” and wholesale market purchases can enhance trade and full participation in regional markets.
- **Theme 6:** In transitioning from voluntary commitments to financially enforceable mandates, GHG accounting practices have the potential to introduce risks and costs to utilities and consumers.
- **Theme 7**: A utility’s position in the value chain can substantially impact the nature of available data and data sharing needs across state borders and with contractual counterparties.
- **Theme 8**: Utilities report increasing demand for transparency and granularity in GHG and clean energy accounting from company boards, end-use consumers, industry advocacy organizations, and lenders.

We highlight the importance of Themes 1, 4 and 6 as high-value opportunities for regional coordination and cooperation. Historically, differences in approaches and flexibility in interpretation of GHG accounting practices have been generally manageable for companies participating in voluntary reporting and programs, such that good-faith reporting efforts have served their purpose even in cases where accuracy may be limited by data availability or methodology differences. Further, differences in the policy objectives underpinning different states’ programs have led to different accounting practices that can be tailored to each circumstance.

Going forward, we anticipate that the introduction of mandatory and more prescriptive SEC disclosures and mandatory state programs will have less flexibility for interpretation; if such programs are materially inconsistent, unclear, or inaccurate the outcome could be to introduce unnecessary risks and costs to utilities and consumers and disrupt markets. In our interviews, several utilities noted specific instances of such inaccuracies that may impose artificial compliance costs on their customers through misallocation of emissions obligations. Select utilities also noted that lack of accurate and commonly-accepted accounting associated with bilateral and spot market purchases may limit their ability to fully participate in regional market expansions, despite common agreement that full market participation and leveraging substantial geographic differences in resource potential will play an increasing role in supporting cost-effective and reliable clean energy transition. Collectively, these observations suggest that a methodologically consistent region-wide GHG emissions allocation and tracking system could offer substantial benefits in the West, particularly for those states engaged in active rulemaking on GHG accounting, that have mandatory deep GHG reduction targets, and that anticipate extensive electricity trade throughout the clean energy transition.

I. Background: GHG Accounting Standards & Guidance

Among the many GHG accounting standards, frameworks, and policies that we document in this catalog, we highlight the Greenhouse Gas Protocol ("GHG Protocol") and forthcoming Securities and Exchange Commission (SEC) disclosure rule as providing essential background in the context of this study. Both the GHG Protocol and SEC rules are under revision and are likely to affect the accounting practices of utilities across the West either directly or indirectly over the coming 1-2 years.

Their role and impact on utilities in the West are as follows:

- **Greenhouse Gas Protocol**: This foundational GHG accounting and reporting document was first published in 2001 by World Resources Institute (WRI) and the World Business Council for Sustainable Development. The GHG Protocol was revised in 2004 and expanded in 2015 with an updated guidance document on recommended best practices for GHG emissions accounting associated with electricity consumption.[6] WRI is currently undergoing another revision cycle, with comments recently due in March 2023 and a rewrite expected sometime in 2024. The GHG Protocol is the foundational source laying out primary GHG accounting principles including the concept of Scope 1, 2, and 3 emissions; approaches to selecting and estimating emissions rates; and methods for allocating emissions across parties.[7] The GHG accounting principles most relevant to this catalog are also described briefly below.

  The role and relevance of the GHG Protocol to utilities in the West is both as a direct source providing guidance for voluntary emissions reporting, and as the prototype that has informed essentially all subsequent voluntary reporting efforts, financial disclosure requirements, and mandatory accounting programs in use by utilities, state policymakers, and the federal government. For example, the GHG Protocol is cited as the primary guidance document informing other accounting programs and reporting frameworks used widely throughout the West, including those issued by The Climate Registry (TCR), the Sustainability Accounting Standards Board (SASB), the Task Force on Climate-Related Financial Disclosures (TCFD), and the Carbon Disclosure Project (CDP).[8]

- **Federal SEC Disclosure Rules**: On March 21, 2022, the Securities and Exchange Commission (SEC) published proposed rules that would require publicly-traded companies to disclose material impacts of climate risks, including required reporting of Scope 1-3 emissions inventories, in their annual Form 10-K.[9] The documentation on GHG accounting practices broadly defers to the GHG Protocol as the basis for accounting practices, citing it as "a leading accounting and reporting standard for greenhouse gas emissions."[10] Final SEC rulemaking is anticipated in 2023, with initial reporting requirements applicable for the year 2023 for large companies, and initial compliance in 2024 or 2025 for smaller companies. Publicly-traded utilities across the West will be required to participate in mandatory SEC

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6 World Resources Institute, *GHG Protocol Scope 2 Guidance, An Amendment to the GHG Protocol Corporate Standard*, 2015.

7 World Business Council for Sustainable Development and World Resources Institute, *The Greenhouse Gas Protocol*, A Corporate Accounting and Reporting Standard, Rev. 2004.

8 *See* The Climate Registry, *Electric Power Sector Protocol for the Voluntary Reporting Program*, 2009; Sustainability Accounting Standards Board, *Electric Utilities Sustainability Accounting Standard*; Task Force on Climate-Related Financial Disclosures, *Recommendations of the Task Force on Climate-related Financial Disclosures*, June 2017; CDP Disclosure Insight Action, *CDP Technical Note: Accounting of Scope 2 emissions: CDP Climate Change Questionnaire*, Version 9, Rev. March 11, 2022.

9 The SEC has an additional rule under development that specifically applies to Environmental, Social, and Corporate Governance (ESG) Funds and will impose similar reporting rules. This may indirectly apply to utilities in the West to the extent that their companies and assets are incorporated into such a fund. Upon adoption of the draft proposal, regulated funds would have 12 to 18 months to comply with changes to the reporting forms. The SEC is still accepting comments for the proposed rule. *See 17 CFR Part 200, 230, 232, 239, 249, 274, and 279 [Release No. IA-6034; IC-34594; File No. S7-17-22]. RIN: 3235-AM96, Enhanced Disclosures by Certain Investment Advisers and Investment Companies about Environmental, Social, and Governance Investment Practices*, 2022.

10 SEC, *17 CFR 210, 229, 232, 239, and 249 [Release Nos. 33-11042; 34-94478; File No. S7-10-22] RIN 3235-AM87*, The Enhancement and Standardization of Climate-Related Disclosures for Investors Proposed Rule, 2022.

disclosures; privately-owned, public power, or otherwise exempt utilities may also be indirectly affected to the extent that lenders and business partners require enhanced emissions accounting information for their own separate compliance purposes. The SEC's financial disclosure rulemaking follows the example of several international jurisdictions toward increased climate risk financial disclosures. Financial disclosure rules already adopted in other jurisdictions such as in the European Union have informed the SEC rule; some of these are already indirectly affecting a subset of US utilities to the extent that that their parent companies, investors, or contractual counterparties are subject to those disclosure rules.[11]

Given the centrality of the accounting principles laid out in the GHG Protocol as both a direct and indirect source, the concepts it lays out have underpinned many of our utility interviews on accounting practices. The utilities that are engaged in the most established accounting programs are fully familiar with these concepts, while utilities in the early stages of reporting are less familiar. For background and reference, we summarize at a high level here the GHG accounting concepts that are the most relevant to this catalog.

FLEXIBILITY AND HEIRARCHY OF QUALITY

As a voluntary GHG accounting and reporting guidance document that seeks to offer usable guidance to a wide range of companies and institutions, the GHG Protocol maintains a substantial level of flexibility in its proposed accounting methods. The GHG Protocol Corporate Standard is intended for intended for entity-level or corporate-level GHG reporting, though it acknowledges that policymakers may utilize relevant portions of standard for the development of mandatory GHG policies.[12]

Its definition of Scope 1, 2, and 3 emissions (direct vs. indirect emissions) allows an entity to distinguish which emissions it has direct control over versus which emissions sources it shares with other entities but can influence via internal practices. It incorporates an expectation that context-specific and company-specific judgement will need to be applied and acknowledges that reporting entities will not always have access to preferred data sources or market instruments. Given these anticipated data limitations, the GHG Protocol provides guidance on the "hierarchy of quality" that encourages reporters to use best available data and methods to accurately track their GHG obligations.[13] The flexibility inherent in the GHG Protocol offers the advantage of enabling many more companies to report than would be feasible if accounting requirements were onerous or required access to generally unavailable data, but also leaves substantial room for accounting practices that are GHG Protocol compliant but yet may differ substantially in the estimated GHG emissions.

SCOPE 1, 2, AND 3 EMISSIONS

The GHG Protocol describes three categories or "Scopes" of GHG emissions, to differentiate the reporting entity's role in creating or causing each category of GHG emissions.[14] The distinction among different emissions Scopes as it pertains to electric utilities is summarized in Figure 1 and is defined as follows:

- **Scope 1: Direct GHG Emissions** are those arising from emissions sources under the reporting entity's direct ownership or control.[15] For an electric utility, power plants operating on fossil fuel are the primary source of Scope 1 emissions (smaller emissions may also arise from utility-owned vehicles,

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11 For example see EUR-Lex, Document 52021PC0189, COM/2021/189 final.

12 As the Protocol states, "Policy makers and architects of GHG programs can also use relevant parts of this standard as a basis for their own accounting and reporting requirements," World Resources Institute, *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard.* P. 5.

13 World Resources Institute, *GHG Protocol Scope 2 Guidance*, 2015, p. 48, Table 6.3.

14 World Business Council for Sustainable Development and World Resources Institute, *The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard*, Rev. 2004. p. 25.

15 As examples of Scope 1 emissions, a manufacturing facility would report its stack emissions under Scope 1; an airline would report emissions from jet fuel combustion in its airplanes.

fugitive methane emissions, fugitive sulfur hexafluoride (SF6) emissions from transmission and distribution operations, or other company operations). The majority of Scope 1 plant emissions are subject to direct regulation from state and federal policies and reporting programs, and are generally straightforward to accurately measure based on fuel consumption and using required emissions monitoring equipment. Typically, because the reporting entity owns or directly controls the equipment responsible for the emissions, this tends to be the most accurate reporting.

- **Scope 2: Indirect GHG Emissions from Energy Consumption** are upstream emissions associated with energy purchased and consumed by the reporting entity (primarily electricity consumption, but also emissions that may be associated with consumption of steam, heating, or cooling energy).[16] The concept of Scope 2 emissions is critical for end-use consumers, since for many consumers, emissions associated with electricity consumption are their single largest source of GHG obligations. For electric utilities however, Scope 2 emissions tend to be small (given that power purchases are typically not made for the purpose of the utility's own consumption, but rather for the purpose of supporting end users' consumption).
- **Scope 3: Indirect Upstream and Downstream GHG Emissions** are other GHG emissions caused by the reporting entity's activities, but created by sources under the direct control of another entity. The nature of Scope 3 emissions can be wide and varied depending on the type of organization in question.[17] For utilities and other energy companies, the largest category of Scope 3 emissions are those associated with their customers' consumption of electricity, natural gas, or fossil fuels. For an electric utility, the primary source of Scope 3 emissions are electricity purchases and associated line losses that are later resold to consumers or other utilities (note that any duplicative direct Scope 1 emissions would be excluded from the utility's tabulation of its own Scope 3 emissions in order to avoid double-counting in a single report).[18]

Figure 1 summarizes Scope 1, 2 and 3 GHG emissions in general, and provides specific examples of emissions as classified into different accounting scopes for generators, vertically integrated utilities, distribution companies, and end-use customers.

[16] Note that for consumers that are both producing and consuming electricity, the Scope 2 Guidance explains, "For accurate scope 2 GHG accounting, companies shall use the total—or gross—electricity purchases from the grid rather than grid purchases "net" of generation for the scope 2 calculation. A company's total energy consumption would therefore include self-generated energy (any emissions reflected in scope 1) and total electricity purchased from the grid (electricity). It would exclude generation sold back to the grid." See World Resources Institute, *GHG Protocol Scope 2 Guidance*. P. 38.

[17] The GHG Protocol considers Scope 3 emissions as optional for reporting, while the proposed SEC disclosures rule would make Scope 3 emissions reporting required if the emissions are material in size or are otherwise covered by a corporate sustainability commitment.

[18] For example, consider the different situations of a utility that is a net purchaser versus a net generator relative to their own customers' needs. For the net purchaser, consider a utility that generates half of the energy supply needed to serve its customers and procures the other half from market purchases. Emissions from self-supply would be reported as Scope 1 emissions, while the emissions from purchases for resale would be reported as Scope 3 emissions. The emissions from self-supply would not be reported twice under both Scope 1 and Scope 3 emissions. For the net generator, consider a utility that generates twice as much energy compared to what is needed to serve its own customers, and sells the rest into a regional marketplace. All emissions from the utility's generation would be reported as Scope 1 emissions (even though only half of the generation is used to supply the utility's customers).

FIGURE 1: DESCRIPTION OF SCOPE 1, 2 AND 3 GHG EMISSIONS

	Generators	Vertically Integrated Utilities	Distribution Companies	End-Use Customers
Scope 1: Direct GHG Emissions				
Emissions from owned/controlled fossil plants	✓	✓		
Fugitive methane emissions from owned/control assets	✓	✓		
Fugitive SF6 emissions from T&D operations		✓	✓	
Company-owned vehicle emissions	✓	✓	✓	
Scope 2: Indirect GHG Emissions from Energy Consumption				
T&D losses		✓	✓	
Purchased and consumed electricity	✓	✓	✓	✓
Energy used in district heating and cooling				✓
Scope 3: Indirect Upstream & Downstream GHG Emissions				
Fugitive emissions from upstream fuel extraction/delivery	✓	✓		
Electricity purchases for delivery to customers		✓	✓	
Employee business travel	✓	✓	✓	

Sources: Adapted from The Climate Registry, *Electric Power Sector Protocol for the Voluntary Reporting Program*. June 2009; and *The Greenhouse Gas Protocol, Chapter 4.*

As a further point of clarification, we note that the classification of the scope of emissions depends on the purpose of the GHG accounting effort. If the utility is developing a GHG inventory for its own corporate purposes, Scope 1 (direct emissions from owned and controlled power plants) and Scope 3 (emissions associated with purchases for resale) will be the largest shares. However, when the utility calculates an emissions factor for the power it sells to its customers, the end-use customers will use that emissions factor to report their own Scope 2 emissions (emissions associated with the consumption of electricity). For a vertically integrated utility serving customers through self-supply and purchases, its Scope 1 plus Scope 3 emissions would equal its customers' Scope 2 emissions. For a distribution-only utility, its Scope 3 emissions would equal its customers' Scope 2 emissions.

From an entity-level accounting perspective, the comprehensive accounting approach is for Organization A to report both its owned (Scope 1) and shared (Scope 2 and 3 emissions), even though the Scope 2 and 3 emissions may also be separately reported as Organization B's Scope 1 emissions. This approach to reporting shared emissions responsibility is not considered double-counting. Instead, this approach clarifies where Organization A has direct control and indirect influence over business activities that generate GHG emissions. It allows for a holistic look at all the places within an organization where action could be taken to reduce emissions.

From a state policy perspective however, it would not be appropriate to tabulate the sum of Scope 1, 2 and 3 emissions across all utilities within a state, as doing so could result in significant double-counting. A self-consistent approach that avoids double-counting would need to trace Scope 1 emissions from the relevant generation-owning companies, through the relevant series of financial and physical transactions that may be reported as the intermediate parties' Scope 3 emissions, and which could then ultimately be reported by specific end-use customers as their Scope 2 emissions. In total across the interconnected grid, aggregate Scope 1 emissions from generators would equal the aggregate Scope 2 emissions reported by end-use customers (i.e., providing either a "production view" or a "consumption view" of GHG emissions responsibility). To the extent that the state policy framework does not have sufficient geographic reach to engage in full generator-to-consumer GHG tracking, it must avoid double-counting in a another fashion such as by carefully defining the policy boundary and reporting responsibility, particularly for emissions associated with imports and exports. While the GHG Protocol provides valuable emissions accounting guidance, it was not created to provide a regulatory framework and therefore modifications may need to be made as its guidance is being applied in a broader regulatory environment.

LOCATION-BASED OR MARKET-BASED ACCOUNTING

For the purposes of estimating emissions rates associated with electricity purchases and consumption, the GHG Protocol offers two options:

- **Location-Based Scope 2 Accounting** allows the reporting entity to utilize a standard average emissions rate associated with their location in the power grid. While the GHG Protocol recommends using the most accurate possible data accounting for regional trade and transmission constraints, it offers substantial flexibility to reporting entities in determining what regional boundary can be used (and specifically references the Environmental Protection Agency (EPA) Emissions & Generation Resource Integrated Database (eGrid) regions as one option).[19] For end-user reporting, utility-specific emission factors are frequently used by customers when available from the utility or through other reporting systems such as the Edison Electric Institute (EEI) reporting database.[20]
- **Market-Based Scope 2 Accounting** allows the reporting entity to tabulate emissions associated with specific power transactions, and apply a hierarchy of quality that prioritizes accounting data (sorted from highest to lowest quality) that is based on or calculated using: (a) bundled and unbundled energy attribute certificates (i.e., RECs); (b) contracts for electricity, including power purchase agreements; (c) supplier emission rates, such as associated with green energy tariffs; (d) residual mix—a production-based emission factor that accounts for renewable attributes already claimed by other reporters; and (e) regional average emission factors.[21]

For reporting entities located in jurisdictions where grid customers can be provided with supplier-specific data, RECs, or related contractual instruments; then the Scope 2 Guidance requires GHG emissions to be reported under both location-based and market-based methods.[22] The Protocol further establishes that RECs included in an inventory using the market-based approach must "uniquely convey GHG emission rate claims to consumers."[23] If supplier-specific data are unavailable, then only location-based method should be reported; the location-based method does not restrict companies from using regional emissions rates that have been calculated without consideration for the final destination of the RECs.[24]

Utilities in the West primarily use the market-based approach for GHG accounting, though regional emissions rates tend to be used for a portion of short-term market purchases. We further note that the market-based accounting concepts have informed several of the state mandatory GHG programs, such as by implicitly utilizing the hierarchy of quality concept that prioritizes the use of power contracts and REC instruments as a component of GHG reporting requirements. Colorado has explicitly adopted a hierarchy of quality methodology in its accounting rules as relevant to Scope 3 emissions (electricity imports/purchases for resale to customers). End use customers also utilize RECs in their own Scope 2 reporting (either directly or indirectly via utility programs). Though REC-based GHG accounting is explicitly incorporated into the GHG Protocol, the utilities we interviewed broadly agree that REC-based GHG accounting can produce inaccurate outcomes (see extensive discussion of this point below).

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19 World Resources Institute, *GHG Protocol Scope 2 Guidance*, 2015, P. 47, Table 6.2.

20 See Edison Electric Institute, "EEI Unveils Electric Company Carbon Emissions and Resource Mix Reporting Database for Corporate Customers," June 18, 2022.

21 World Resources Institute, *GHG Protocol Scope 2 Guidance*, 2015, P. 48, Table 6.3.

22 World Resources Institute, *GHG Protocol Scope 2 Guidance*, 2015, P. 59.

23 *Id.* P. 63.

24 *Id.*, P. 63.

MARKET BOUNDARIES

The GHG Protocol offers guidance on the concept of the geographic boundaries that are pertinent for reporting purposes, which can generally be used for two purposes: (1) to identify the boundaries of the region within which clean energy purchases (whether wholesale energy+REC contracts or REC-only purchases) should be procured in order to claim GHG-free power supply delivered to a specific set of customers; and (2) to set the region that the reporting entity should utilize to estimate the emissions rate associated with market purchases.[25] The GHG protocol offers guidance that chosen market boundaries and associated emissions rates could reflect some combination of Regional Transmission Organization (RTO) market regions, account for the extent of interregional trade, and align with regulatory boundaries if possible. However, as with many other elements of GHG Protocol guidance, the selection of market boundaries is inherently flexible and subject to the reporter's judgement.

For the utilities we interviewed, eGrid region rates, RTO market region emissions rates, or regulator-approved rates were commonly utilized for the determination of emission rates, while state-determined geographic or deliverability qualification criteria are used to guide REC or wholesale energy+REC purchases.

RESIDUAL SYSTEM MIX

The GHG Protocol further recommends the use of "residual system mix" rather than total "grid average" emissions rates to estimate the GHG intensity of any unspecified market purchases.[26] Grid average rates, such as produced within the eGrid data, tabulate the total emissions within the defined grid boundary divided by total production, and do not account for the possibility that other GHG reporting entities may have claimed the GHG-free power supply from their owned and contracted resources. If all entities were to claim their own GHG-free supply resources and use the grid average rate for any market purchases, the result is that multiple entities would claim a share of GHG-free energy supply from the same resource.

Residual system mix rates aim to prevent the potential for double counting by identifying the portion of clean or other supply resources that have already been claimed by a different reporting entity (e.g., through REC retirement) and subtract these resources from the supply mix. The emissions and MWh produced from the remaining resources are then used to calculate a higher emissions intensity for the residual grid mix that is relevant for market purchases. For example, the Green-e certification and data support program seeks to provide an independent certification of RECs and associated residual system mix emissions rates for reporting entities.[27] Some state programs use a similar concept when stipulating the GHG emissions rates relevant for unspecified market purchases.

GHG EMISSIONS ASSOCIATED WITH ACQUISITIONS, ORGANIC GROWTH AND DIVESTITURE

For companies that wish to track and report emissions and progress to GHG commitments over time, a common situation is that structural changes to the organization such as mergers and acquisitions can give the appearance of large year-over-year changes to GHG emissions (even if physical emissions have not materially changed). For example in the power sector, a merger of two similarly-sized companies could appear to double GHG emissions, or spinning off a company's fossil fuel assets into a separate company could appear to eliminate GHG emissions. In both cases, the GHG Protocol recommends that these structural changes should be accounted for by recalculating historical company GHG emissions over time to most accurately convey the new organizational structure. In a merger, the combined historical emissions of the two companies would be reported; while emissions associated with a spinoff would be

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[25] *Id.*, p. 64–65, Table 6.2.

[26] *Id.*, p. 56–57, Table 6.3.

[27] Center for Resource Solutions, *Green-e Renewable Energy Standard for Canada and the United States*, Rev. 2022.

removed from the historical reporting years.[28] These structural changes are treated differently from organic growth or reductions to GHG emissions (e.g. building a new fossil plant or permanently retiring such a plant), which are considered accurate depictions of GHG emissions over time.

Accounting for structural changes for utilities can in some cases introduce substantial complexity, for example if the utility is regularly adjusting its equity share or ownership control of substantial power assets. Accurately accounting for such changes may either require excess effort to constantly recalculate historical emissions levels, or setting a materiality threshold on structural changes that is relatively high but that may reduce the ability to correct for structural changes.

[28] World Resources Institute, Greenhouse Gas Protocol, Chapter 5.

II. Renewable and Clean Electricity Supply Targets

A summary of the RPS programs and clean electricity supply targets is located below in Table 2. The utilities we surveyed operate in 11 states that currently have a binding RPS; another two states (North and South Dakota) have voluntary RPS programs. RPS programs are technology standards that mandate that utilities supply certain percentages of retail electricity sales with renewables. The mechanism for demonstrating compliance with RPS programs is through the surrender of RECs, reflective of the required MWh volume of qualified renewable resources. The production, transfer, and retirement of RECs is tracked by the regional attribute tracking systems: the Western Renewable Energy Generation Information System (WREGIS) and the Midcontinent ISO region renewable energy tracking system (M-RETS).[29] The RECs tracked through these systems have unique identifiers and can only be retired once, which prohibits the double-counting of any single REC, so long as programs that allow RECs require retirement for compliance. The timing of when RECs are minted and put into generator and utility accounts is somewhat delayed relative to the timeframe of physical energy production, such that RECs can be transferred and retired prior to state compliance deadlines (but which limits the ability to utilize the REC systems for closer-to-real-time tracking or other time-sensitive use cases).

Across RPS programs, there are broad similarities in program design and qualified resources. Wind and solar contribute to the largest share of retired RECs, while nuclear and large hydroelectric resources are generally not eligible for RPS compliance. The states differ in how they define the geographic scope of eligible resources, with most states qualifying resources within the same regional REC tracking system (WREGIS or M-RETS). However, four states (California, New Mexico, Oregon, and Utah) place limits on the volume stand-alone REC purchases (RECs that are purchased separately from energy contracts) that utilities can use to comply with RPS requirements.[30]

Through the REC-tracking system, the quantity of renewable energy produced over the course of a year can be exactly matched with the quantity of RECs produced on a system-wide basis. However, these volumes may not accurately correspond with the quantities required for RPS compliance in those same years, given that state RPS programs usually offer some flexibility in compliance, such as through:

- **Under-compliance penalties or cost threshold rules** that can mean that some load serving entities might retire fewer RECs than the RPS target if paying the penalty is lower cost than purchasing more RECs or if the cost of RECs is too high relative to another cost-effectiveness threshold. For example, in Washington, a penalty of $50/MWh applies for missing RPS targets, and utilities are not required to meet the target if the cost of doing so would exceed 4% of retail sales revenue (measured as cost above a non-renewable alternative source of supply).[31] Many other states have similar provisions to protect against excess costs that can sometimes result in retired REC volumes below the standard.
- **Banking or excess compliance provisions** that allow load serving entities to save a portion of any excess REC holdings to be used for compliance in future years, the effect of which may mean that RPS compliance volume reporting could exceed the megawatt-hours of renewable supply produced in the later year. As two examples, Colorado allows up to five years of REC banking and Arizona allows unlimited banking.[32]

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29 WECC.org, Western Renewable Energy Generation Information System and M-RETS (mrets.org).

30 The State of California created portfolio content categories that govern the eligibility of RECs. *See* California Public Utilities Commission, *60% RPS Procurement Rules*; New Mexico's RPS requires that RECS must be "transferred to the purchaser of the electricity." *See* *New Mexico Statutes*, Chapter 62, Article 16; Oregon and Utah both set caps on the percentage of unbundled RECs that can be applied to comply with the respective RPS targets. *See* *Oregon Revised Statutes*, Chapter 469A, Section 145 and *Utah Code*, Title 54, Chapter 17, Section 602.

31 DSIRE, Renewable Energy Standard, Program Overview: Washington Renewables Portfolio Standard, updated November 3, 2022.

32 DSIRE, Renewable Energy Standard, Program Overview: Colorado Renewables Portfolio Standard, updated November 18, 2022; and DSIRE, Renewable Energy Standard, Program Overview: Arizona Renewables Portfolio Standard, updated November 18, 2022.

- **Volume multipliers,** where RECs produced by certain policy-preferred clean resources may be retired with a volume multiplier on compliance value (such that 1 REC produced by such a preferred resource may be utilized to receive greater than 1 REC worth of compliance). For example, in Utah a volume multiplier of 2.4 can be awarded for surrendering RECs associated with solar projects; in Colorado and Oregon volume multipliers of 1.25–3 can be awarded for certain community solar or other prioritized project categories.[33]

In addition to RPS programs, 9 states have adopted 100% clean electricity supply mandates or goals that have been issued with varying levels of specificity and enforcement. None of these state goals is presently enforced through a clean energy standard (CES) using a system of clean energy certificates or zero emissions certificates (*i.e.,* analogous to RPS compliance via RECs).[34] Instead, these 100% clean electricity supply targets have been pursued through utility Integrated Resource Plan (IRP) processes and/or are the subject of further regulatory implementation planning. In some cases the legislation or executive order refers to the targets ambiguously or interchangeably as 100% clean supply versus 100% (net) GHG reduction mandates, which can leave an open question as to whether achievement is ultimately to be attained by ensuring sufficient supply was produced (as analogous to the REC system), how and how much offsetting of GHG-emitting supply is acceptable, and whether achievement will be primarily measured relative to clean supply or relative to GHG reductions. For the states that have developed their clean electricity supply targets into mandatory GHG accounting and reduction programs, these clean electricity targets are dual-listed in this catalog in Section IV below.

Among the utilities interviewed, there is a consensus view that REC tracking systems are adequate to support the purpose for which they were originally designed: to stimulate investment in renewable supply, support utility and customer renewable contract arrangements, prevent double-counting of REC claims, and confirm compliance with each state's RPS requirements.

However, there is also a consensus or near-consensus view among interviewed utilities that REC instruments do not have a clear alignment with GHG accounting practices, and when utilized for GHG accounting purposes can create inconsistencies. RECs equate to a megawatt-hour of renewable production, but they do not necessarily correspond to a particular quantity of GHG abatement nor GHG-free delivered supply to any one customer group (see examples in Sections III and V below). Many large sources of legacy carbon-free energy sources (particularly hydro and nuclear) generally do not qualify as RPS-eligible resources RECs and so using RECs as a method to track carbon free power leaves a substantial accounting gap pertinent to these large clean energy resources. Further, because RECs only account for renewable energy production, they may be inadequate policy tools to track the impact of programs aimed at incentivizing activities that reduce emissions but do not necessarily generate renewable energy (e.g. peak shaving, energy consumption profile management, energy efficiency, hydropower resource management, and battery/vehicle resource management). Even so, most of the interviewed utilities have cited examples where RECs are currently being used for various purposes in GHG accounting or emissions rate calculations as required within other state policies, in support of end-use customer claims and programs, or within formalized or informal voluntary reporting efforts.

A general challenge is that RECs have been developed for a specific purpose (RPS compliance demonstration) but are being repurposed for other uses including for GHG accounting, calculation of carbon intensity, or claims of reductions. Though not a fit-for-purpose instrument, the current reality is that in some cases RECs are the most defensible option that is available today. No similar region-wide tracking system exists to support the unique and self-consistent tracking of GHG allocations or reduction

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33 DSIRE, Renewable Portfolio Goal, Program Overview: Utah Renewables Portfolio Standard, updated July 3, 2018; and DSIRE, Renewable Energy Standard, Program Overview: Colorado Renewables Portfolio Standard, updated November 18, 2022.

34 Though not presently utilized in the West, we note that other states such as Illinois, New York, and Massachusetts have defined products such as clean energy certificates and zero emissions certificates for the purposes of quantifying the production of clean electricity from non-RPS-qualified but otherwise clean resources such as nuclear and large hydropower resources. *See* Illinois Power Agency Act, Section 1-75(d-5); *See* New York Clean Energy Standard; *See* Massachusetts Clean Energy Standard.

claims. Further, RECs are explicitly acknowledged under GHG protocol as a viable option for end-user GHG reporting as discussed above. Given these realities, RECs are likely to continue to be used unless and until a more relevant methodology, instrument, or suite of instruments become available.

TABLE 2: OVERVIEW OF RPS AND CLEAN ELECTRICITY TARGETS IN THE WEST

State (Initial Year)	RPS	Clean Energy Targets or Mandates	Notes
Arizona (2006)	15% by 2025		
California (2013 RPS, 2018 Clean)	60% RPS by 2030	100% GHG neutral by 2045 (legislation)	Three Portfolio Content Categories: • Bundled (>75% required) • Firmed and shaped REC • Unbundled (<10% required)
Colorado (2008 RPS, 2020 Clean)	IOUs: 30% RPS by 2020 Public Power: 10-20% RPS by 2020	100% carbon-free by 2050 (legislation)	
Michigan (2012 RPS, 2020 Clean)	15% RPS by 2021	Carbon neutral by 2050 (executive order)	
Minnesota (2012 RPS, 2023 Clean)	Xcel: 31.5% RPS by 2020 Others: 26.5% RPS by 2025	100% carbon-free by 2040 (legislation)	
Nevada (2006 RPS, 2019 Clean)	50% RPS by 2030	100% carbon neutral by 2050 (legislation)	
New Mexico (2015 RPS, 2019 Clean)	80% RPS by 2040	100% carbon-free by 2045 (legislation)	Eligible RECs must be bundled with electricity
North Dakota (2015)	Voluntary 10% RPS by 2015		
South Dakota (2015)	Voluntary 10% RPS by 2015		
Oregon (2015 RPS, 2021 Clean)	Investor-owned: 50% RPS by 2040 Consumer-owned: 25% RPS by 2025	Investor-owned & direct-access electricity service suppliers. 100% GHG reduction in retail sales by 2040 (legislation)	Unbundled RECs are eligible for only up to 20% of each utility's compliance
Utah (2025)	20% RPS by 2025 + 20% annual increase each subsequent year		Unbundled RECs are eligible for only up to 20% of each utility's compliance
Washington (2012 RPS, 2019 Clean)	15% RPS by 2020	GHG-neutral by 2030. 100% carbon-free by 2045 (legislation)	
Wisconsin (2010 RPS,2019 Clean)	10% by 2015	100% carbon-free by 2050 (executive order)	

Sources:

Clean Energy States Alliance. "Table of 100% Clean Energy States."
Arizona: *Arizona Administrated Code*, Title 14, Chapter 2, Article 18, Renewable Energy Standard and Tariff.
California: *California Public Utilities Code*, Division 1, Part 1, Chapter 2.3, Article 16, California RPS Program.
Colorado: State of Colorado Senate Bill 19-236
Michigan: *Michigan Compiled Laws*, Chapter 460, Section 10r.
Minnesota: *2022 Minnesota Statutes*, Chapter 216B, Section 1691, Renewable Energy Objectives.
Nevada: *Nevada Revised Statutes*, Chapter 704, Section 782.
New Mexico: *New Mexico Statutes*, Chapter 62, Article 16, Section 4, Renewable Portfolio Standard. *New Mexico Statutes Annotated*, Chapter 62, Article 16, Rev. 2019.
North Dakota: *North Dakota Century Code*, Title 49, Chapter 2, Section 28, State Renewable and Recycled Energy Objective.
South Dakota: *South Dakota Codified Laws*, Title 49, Chapter 34A, Section 101, State Renewable, Recycled, and Conserved Energy Objective Established.
Oregon: *Oregon Revised Statutes*, Volume 13, Chapter 469A, Renewable Portfolio Standards.
Utah: *Utah Code*, Title 54, Chapter 17, Section 602, Carbon Emission Reductions for Electrical Corporations.
Washington: *Revised Code of Washington*, Title 19, Chapter 285, Energy Independence Act.
Wisconsin: *Wisconsin Statutes & Annotations*, Chapter 196, Section 378, Renewable Resources.

III. Customer Energy Mix and GHG Intensity Disclosure Programs

Utilities in our surveys are subject to 9 different energy supply mix and/or GHG content disclosure programs (Washington having 3 separate programs, one for energy mix, one for emissions intensity and one for GHG disclosures), as summarized in Table 3. The purpose of these programs is to inform customers about the sources of their power supply and (in most of the programs) the GHG emissions associated with that power supply. For the most part, these programs take a “consumption view” that seeks to explain to customers their supply resource mix (whether generated by their utility or by a different power company). To estimate the quantity of electricity supply from the various fuel sources as tabulated on an annual basis, utilities account for their owned resources, purchases through bilateral contracts, and short-term market purchases. In some cases, if customers wished to change their individual supply mix or contribute to increases in renewable supply on the system they can do so, such as through participating in utility green tariffs or related programs. In most cases, energy supply mix reporting separately tracks the supply allocated to customers participating in green tariffs from supply allocated to the broader customer base. Unlike RPS programs, energy mix disclosures typically require some reconciliation or allocation between a utility’s wholesale sale activity and retail load service.

Electricity energy supply mix disclosure programs were first implemented two decades ago over the timeframe 1997–2001, and so long predate the same states’ more recent RPS standards and 100% clean electricity targets. For that reason, each of these programs is relatively mature and offers a well-documented set of rules and accounting practices that must be used by utilities when calculating the supply mix. The maturity of these programs can introduce inconsistencies in reporting outcomes for utilities however, since they tend to result in a calculated supply mix that can be inconsistent with reporting under the more recently-adopted RPS, GHG reductions programs, or utilities’ voluntary GHG accounting practices. Even comparing programs within a single state, utilities report that the prescribed accounting practices cause them to report different GHG emissions rates under energy mix versus mandatory GHG disclosure rules.

The inconsistencies may range from minor to substantial, but tend to arise from:

- **REC purchases are typically attributed to utility customers** as an initial accounting step, which can have the effect that the total of these RECs+physical supply of qualified renewable energy can exceed total customer sales (either because stand-alone REC purchases are allocated to the utility’s customers or if a utility’s total physical supply exceeds its total customer sales). In either case, the excess fossil supply can be implicitly or explicitly allocated to off-system customers who may not claim the associated emissions. The method for determining which excess supplies should be allocated to off-system sales versus the load serving entity’s customers can produce materially different results. For example, in California customers are first allocated all non-emitting supply (renewables, nuclear, hydro), then coal supply, then gas.[35]
- **REC banking and deliverability provisions that may create apparent inconsistencies** between RPS compliance and energy supply mix disclosures. For example, Oregon RECs may be banked and used for RPS compliance for up to five years beyond the year the attribute is issued.[36] However, for supply mix reporting purposes, the renewable resource in question will only be accounted for in the year of production, creating an inconsistency. As another example, in California, stand-alone REC purchases cannot be accounted for within the power source disclosures (meaning that one can be compliant with the RPS, even if the share of renewable supply reported in the supply mix disclosure falls below the RPS requirement).

[35] California Energy Commission, PSD Frequently Asked Questions.

[36] *Oregon Revised Statutes*, Chapter 469A, Section 140.

- **Unspecified or market purchases** are usually reported as a distinct category of supply, with rules for specifying how the emissions rate is to be calculated. In California and Washington, rates of 0.428 and 0.437 metric tonnes of CO_2e/MWh (approximately consistent with a gas combined cycle plant) are used to estimate emissions associated with unspecified purchases, a number that was originally derived from a year 2010 Western Climate Initiative (WCI) analysis of marginal emissions rates in the West.[37] The rationale for using the selected rate is that (at least at that time), a gas combined cycle plant was anticipated to be the incremental or marginal resource that would most often be dispatched to serve the next incremental megawatt-hour of demand. Many utilities we interviewed disagree that this conclusion is still relevant. For example, a static, annual emissions rate for unspecified market purchases accounts for neither the overall incremental greening of the grid due to state-level regulatory program implementation and investments, nor the high GHG emissions consequences of peak power demand (see additional discussion in the context of interactions between GHG accounting and wholesale power markets below). Other states, such as Michigan and Nevada, allow for the use of regionally-averaged emissions rates for calculating emissions associated with unspecified purchases. We note that neither the marginal nor system average rate accurately matches the concept of the "residual mix" emissions rate that is recommended to be used by the GHG Protocol (emissions that remain after subtracting the supply mix and attributes claimed by other entities).
- **National application of federal incentive programs** may prove challenging if federal programs and each state use different approaches to estimating supply mix and GHG intensity of consumption. As an example that is under active rulemaking by the US Department of the Treasury, the Inflation Reduction Act section 45V includes a tiered production tax credit available for hydrogen production.[38] Hydrogen produced with lower lifecycle GHG emissions is eligible for higher tax credit amounts, up to a total of $3 per kg of produced hydrogen. There are carbon intensity thresholds that must be met to qualify for the production tax credit. How unspecified market purchases and emissions factors for grid electricity in different regions is calculated, including accounting for time-granularity and deliverability of any associated renewable purchases, are open questions that will materially affect access to the tax credit across the country and may result in inconsistencies with state-level reporting programs.

Utilities have mixed views on the importance of inconsistencies or inaccuracies in energy supply mix disclosure programs. The primary concerns identified by utilities are associated with perceptions or confusion, for example with customers or press members pointing out apparent inconsistencies between programs. As a result, some end-use customers may have incorrect or insufficient information on GHG obligations to use within their own company sustainability reporting efforts. Several utilities expressed that supply mix disclosure programs would be improved if they were updated to ensure self-consistency with mandatory GHG accounting programs. In one utility interview, a view was expressed that the state's supply mix disclosure program outlived its usefulness once a mandatory GHG reduction program was adopted, the supply mix of which could be used for reporting purposes.

Other utilities take the view that as long as reporting rules are clear, any resulting inconsistencies can be attributed to the different purposes of various programs. Further, given that energy supply mix disclosure programs are informational in nature, they do not impose any costs or obligations on utilities or customers. For this reason, most utilities did not highlight inconsistencies or inaccuracies in supply mix and GHG disclosure programs with the same level of concern as inaccuracies that could arise under mandatory reduction programs.

37 California Air Resources Board. Public Hearing to Consider the Proposed Amendments to the Regulator for the Mandatory Reporting of Greenhouse Gas Emissions. *Staff Report: Initial Statement of Reasons*. September 4, 2018. P. 16.

38 See Department of the Treasury, "Request for Comments on Credits for Clean Hydrogen and Clean Fuel Production."

TABLE 3: CUSTOMER ENERGY SUPPLY MIX AND GREENHOUSE GAS INTENSITY DISCLOSURE PROGRAMS

State & Program Name (Initial Year)	Measuring Methodology	Value of RECs	Framework for Imports/Exports	Unspecified GHG Rate
California Power Source Disclosure Program (1997, CA Energy Commission)[39,40]	Average generation and emissions rates using adjusted net purchases	Unbundled RECs are not eligible	If net purchases exceed retail sales, purchases are subtracted following a hierarchy of resource types until purchases equal retail sales	0.428 metric tonnes CO_2e/MWh[41]
Colorado Component and Source Disclosure (1999, CO Public Utilities Commission)[42]	Average generation	RECs assigned to retail customers	Unidentifiable imports are to be listed as "imported, fuel source unknown"	Source region average, estimated for future year
Idaho Fuel Mix Disclosure (2007)[43]	Average generation	Energy mix (not REC-based)	Purchases reported as "other"	Undefined
Michigan MCL Section 460.10r (2000, MI Public Service Commission)[44]	Average generation and emissions rates	RECs assigned to retail customers	Resource-specific reporting if possible, otherwise regional rates can be used	Regional average of MI, IL, IN, OH, and WI (updated twice annually) 2022 value: 0.483 metric tonnes[45]
Nevada NRS 704.763 & NAC 704.2785 (2001, Public Utilities Commission of Nevada)[46]	Average generation emission rates accounting for known imports and exports (does not require residual mix to be used)	Unrelated	• Exports are ascribed the state average mix • Imports are modeled as an equal mix of 11 nearby states[47]	Based on an average emission rate mix of 11 nearby states
Oregon Electric Company and Electricity Service Suppliers Labeling (1999, OR Public Utility Commission)[48]	Average generation and emission rates	RECs assigned to retail customers	Exports are to be excluded	Company-specific purchased power source mix
Washington Fuel Characteristics Disclosure (2000, WA Department of Commerce)[49]	Average generation	RECs assigned to customers	Energy mix permits use of Bonneville Power Administration (BPA) system mix for BPA purchases	Undefined
Washington Energy Independence Act (2006 Act, 2015 WA Utilities and Transportation Commission Rules)[50]	Energy intensity per customer and per capita, GHG total emissions	RECs not used	• Imported supply is resource specific if available • Generation partly serving out-of-state customers supply is prorated to WA customers' share	0.437 metric tonnes CO_2e/MWh
Washington Clean Energy Transformation Rule: GHG Content Calculation (2021, WA Department of Ecology)[51]	Emission rates are calculated using a production view	RECs not used	• Imports are ascribed the generator's emission rate, if available • Exported electricity is not included in the calculation	0.437 metric tonnes CO_2e/MWh

39 *California Code of Regulations*, Title 20, Division 2, Chapter 3, Article 5. Electricity Generation Source Disclosure.

40 California Energy Commission, California Power Content Label.

41 *California Code of Regulations*, Title 17, Division 3, Article 2, Mandatory Greenhouse Gas Emissions Reporting.

42 *Code of Colorado Regulations*, CCR #4 723-4 4 CCR 723-3, P3406. Colorado Department of Public Health and Environment. *Clean Energy Plan Guidance.* March 2021.

43 Idaho Legislature Energy, Environment, and Technology Interim Committee, *2012 Idaho Energy Plan*, 2012, p. 119.

44 *Michigan Compiled Laws*, Chapter 460, Act 3 of 1939, Section 460.10r.

45 Michigan Public Service Commission, *Fuel Mix Disclosure Data*, 2022.

46 *Nevada Administrative Rules*, Chapter 704—Regulation of Public Utilities Generally, Sections NRS 704.763 and NAC 704.2785.

IV. Mandatory Greenhouse Gas Emissions Reporting and Reduction Programs

Utilities we interviewed are subject to 10 mandatory GHG reporting and/or reduction programs. Among these, we further subcategorize by scope, purpose, and implementation mechanism:

- **Emissions Scope Covered:** Two programs (WA, US EPA) cover Scope 1 emissions (i.e., requiring the reporting of direct emissions from large facilities), while the remaining 8 programs cover Scope 1–3 emissions and seek to report some or all emissions associated with electricity imports to the state and consumed by retail customers. Six of the programs (CA×2, WA×2, US×2) are economy-wide in scope, while the remaining four programs (CO, OR×2, WA) are focused only on the electricity sector. Further, as noted in Section II above, an additional 5 states have adopted 100% clean electricity or GHG elimination goals that are not discussed in this section of the report because the implementation and enforcement mechanisms are not yet sufficiently described.
- **Primary Purpose**: The mandatory GHG programs reviewed have been developed for the distinct purposes of: (a) 4 programs (CA, OR, WA, US EPA) are mandatory GHG reporting regimes that seek to inform government agencies, the public, and ratepayers of the volume of emissions associated with electricity (or economy-wide) emissions sources and consumption; (b) 5 programs (CA, CO, OR, WA×2) require mandatory reductions to GHG emissions associated with electricity production and consumption; and (c) 1 program, the SEC disclosure rule, seeks to ensure that investors in U.S. companies across all economic sectors will have sufficient information about climate-related risks (including exposure to GHG emissions obligations) to inform investment decisions and company oversight.
- **Implementation Mechanism:** Among the 5 mandatory GHG reduction programs, 2 (CA and WA) incorporate a GHG emissions cap-and-trade regime. The other 3 mandates will be achieved primarily through utility compliance plans, integrated resource plans, and ex post verification; incentives and penalties that some utility commissions are authorized to utilize to incentivize on-time or early achievement (while balancing against cost and preventing rate shocks); and/or through future state policies that have yet to be developed. In some cases, the mandates have explicitly left open issues related to treatment of unspecified purchases and how to achieve "100%" in the context of a utility's continued (or enhanced) reliance on market purchases where a grid mix or some average or residual emissions rate is applied.

These mandatory GHG reporting and reduction programs were prioritized in our utility interviews as the primary focus of ongoing work and the greatest potential accounting challenges. This prominence arises because the majority of the programs in question have been recently introduced (more than half within the past five years) and are the subject of ongoing regulatory policy-making and implementation planning. Between expanded state programs and the new SEC disclosures rule, many more utilities will face mandatory GHG reporting requirements and may face enhanced scrutiny on accounting practices.

The transition from informational reporting to mandatory reductions programs elevates the financial implications and risks associated with inaccurate accounting practices. Any inaccuracies or double-

[47] Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming.

[48] *Oregon Administrative Rules*, Chapter 860, Division 38, Section 0300—Electric Company and Electricity Service Suppliers Labeling Requirements.

[49] *Revised Code of Washington*, Title 19, Chapter 19, Section 29A.60—Fuel Characteristics Disclosure-Electricity Product Categories.

[50] *Washington Administrative Code,* Title 480, Chapter 109, Section 300, "Greenhouse gas content calculation and energy and emissions intensity metrics."

[51] *Washington Administrative Code*, Title 173, Chapter 444, Section 173-444-040—Greenhouse Gas Content Calculation. Washington State Department of Commerce, *Fuel Mix Disclosure.*

counting of emissions across different organizations' Scope 1, 2 and 3 emissions, which may be appropriate in the context of informational disclosures, becomes more problematic as programs become mandatory and financial penalties are applied. Inaccurate GHG accounting could produce excess costs through excess GHG obligations (including associated allowance purchase costs or penalty rates); imposing costly operating constraints on specific resources; introducing barriers to trade; or driving less cost-effective resource investment and retirement outcomes. Ongoing and future policymaking efforts mean that the present moment holds substantial uncertainty and risks associated both with detailed accounting rules and even with relatively foundational policy questions. For example, several states' legislation leave substantial ambiguity with respect to what will constitute the eventual achievement of 100% (net) GHG-free electricity service.[52] Different definitions of 100% (net) zero may dictate a substantially different resource mix. Yet, the resources that utilities are developing in the present investment cycle are the same resources that will need to provide reliable and affordable electric service under the 80-100% clean electricity system required by 2030-2050 in several states.

[52] For example, alternative definitions of 100% clean electricity could mean any of the following: (a) 100% clean energy standard, demonstrated by the retirement of 100% clean energy certificates in state or out of state (with limited or no enforcement of in-state emissions elimination or deliverability); (b) 100% in-state fossil elimination, plus 100% clean energy standard; (c) time-granular GHG tracking of in-state emissions and GHGs embedded in imports and exports, such that net GHG emissions associated with in-state consumption and trade balance to zero; (d) granular enforcement of zero in-state GHG emissions, with time-granular tracking of GHGs in imports (and displaced by clean energy exports) to ensure a net zero or net negative GHG obligation over the year; or (e) an absolute zero GHG emissions obligations, enforced internally and upon imports on a granular time basis. Each of these potential definitions of 100% (net) zero has a very different associated outcomes in terms of in-state emissions, policy interpretation of the residual GHG emissions obligations, resource mix needed, and associated consumer costs. Further, other than for definition (a), current GHG measurement and tracking practices will not be sufficient to accurately measure achievement in a self-consistent fashion as utilities and states move further along the achievement pathway.

TABLE 4: MANDATORY GHG EMISSIONS REPORTING AND REDUCTION PROGRAMS

State and Program (Initial Year)	Reporting Scope & Entity	Reduction Target	Compliance or Allowance Mechanism	Framework for Imports/Exports	Unspecified GHG Rate
US EPA GHG Reporting Program (2010)	Scope 1, economy-wide, facilities ≥10,000 MT CO_2e/year	n/a	n/a	n/a	n/a
US SEC Climate-Related Risk Disclosures (Proposed 2022, final expected 2023)	Scope 1–3, economy-wide, publicly traded companies (i.e., SEC registrants)	n/a	n/a	Reference to GHG Protocol	Reference to GHG Protocol
CA Mandatory Reporting Rule (2007) CA Air Resource Board	Scope 1–3, economy-wide, facilities & entities ≥10,000 MT CO_2e/year	n/a	n/a	First jurisdictional deliverer is responsible	0.428 tonne CO_2e/MWh[53]
CA Cap and Trade (2012) CA Air Resource Board	Scope 1–3, economy-wide, facilities & entities ≥25,000 MT CO_2e/year	40% by 2030	CA GHG allowances (linked with Québec)	First jurisdictional deliverer is responsible.[54] Contract-specific emissions rates (RECs qualify if bundled)[55]	0.428 tonne CO_2e/MWh
CO GHG Reporting and Emission Reduction Requirements (2020) CO PUC; CO Dept. of Public Health and Environment	Scope 1–3, electricity sector, retail electricity service providers	80% by 2030 100% by 2050	Utility compliance plans with agency oversight	Hierarchy of quality with transaction-specific accounting if possible (e.g., facility, company, region, market)	May vary depending on source
OR GHG Reporting Program (2015) OR Dept. of Environmental Quality	Scope 1–3, electricity sector, facilities & entities ≥2,500 MT CO_2e/year	n/a	n/a	Unspecified purchases rate; Multi-state utilities ascribed a system emission factor	0.428 tonne CO_2e/MWh
OR Clean Energy Targets (2021) OR Dept. of Environmental Quality	Scope 1–3, electricity sector, all retail electricity providers	80% by 2030 90% by 2035 100% by 2040	Utility compliance plans, commission oversight and incentives for early compliance[56]	Unspecified purchases rate; Multi-state utilities ascribed a system emission factor	0.428 tonne CO_2e/MWh
WA Clean Air Act (1991) WA Dept. of Ecology	Scope 1, economy-wide, facilities ≥10,000 MT CO_2e/year	n/a	n/a	n/a	0.437 tonne CO_2e/MWh
WA Clean Energy Transformation Act (2019) WA Utilities and Transportation Commission; WA Dept. of Commerce; WA Dept. of Ecology	Scope 1–3, electricity sector, all retail electricity providers	2025: No coal in rates 2030: GHG neutral 2045: 100% non-emitting	Utility compliance plans, penalties excess reliance on fossil ($60/MWh for gas CC, $84/MWh gas peaker, $150/MWh coal), with escalation[57]	20% of GHG-neutral obligation may be satisfied using unbundled RECs	0.437 tonne CO_2e/MWh
WA Climate Commitment Act Cap & Invest Program (2023) WA Department of Ecology	Scope 1–3, most economic sectors, entities ≥25,000 MT CO_2e/year	45% by 2030 70% by 2040 95% by 2050	WA GHG allowances (no linked jurisdictions)	First jurisdictional deliverer is responsible. Contract-specific emissions rates	0.437 tonne CO_2e/MWh[58]

53 *California Code of Regulations*, Title 17, Division 3, Chapter 1, Subchapter 10, Article 2—Mandatory Greenhouse Gas Emissions Reporting.

54 The Executive Officer (of CARB) directly retires a portion of allowance allocation for distribution utilities that make EIM purchases. Cal. Code Regs. tit. 17, § 95892

55 California Air Resources Board, Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, pp. 118–122.

56 Oregon Legislature, External memo: Clean Energy Bill Summary, October 12, 2021.

57 Washington State Legislature, RCW 19.405.090: Compliance, enforcement, and penalties—Alternatives.

58 *Revised Code of Washington*, Title 19, Section 405.070—Greenhouse Gas Content Calculation.

Utilities described a wide variety of challenges and gray areas associated with GHG accounting practices, as follows:

- **Scope 1 direct emissions reporting programs** were described as clear and well-established. Given that measurements can be derived from plant emissions monitoring equipment and do not cross organizational boundaries in the same way as Scope 2–3 emissions, these programs have not introduced accounting challenges to the utilities we interviewed.
- **Emissions tracking associated with electricity imports** into jurisdictions with mandatory GHG reporting (and especially reductions) are a critical source of accounting challenges for the utilities we interviewed. The need to track emissions associated with imports arises from each state's separate jurisdictional authority to introduce law and regulation governing the emissions of in-state power plants, but that does not extend outside of state borders. Therefore, the states typically impose an obligation to report or reduce GHG emissions under a "first jurisdictional deliverer" approach, such that the utility or load-serving entity that imports electricity into the state is responsible for reporting (and, if relevant, paying for) any associated GHG emissions. The importer-based obligations approach is conceptually elegant but has produced innumerate accounting complexities for multi-jurisdictional utilities and utilities that make both purchase and sale transactions under long-term contracts (often resource-specific), mid-term bilateral purchases (often not resource-specific), short-term schedules implemented via e-Tags, and through the Western Energy Imbalance Market (EIM). Any imports from an unverified source are accounted for at an unspecified purchases emissions rate (e.g., 0.428 tonnes/MWh in California). Since California's cap-and-trade program was initially implemented in 2012, rules around GHG imports accounting have been the subject of substantial focus and change as California Air Resources Board (CARB) has sought to provide more guidance on rules to prevent resource shuffling.[59]
- **Hierarchy of quality and requirements for transaction-specific accounting** is implicitly endorsed to some extent in several state programs that require or prioritize contract-specific accounting where possible. Colorado's approach explicitly requires the application of a quality hierarchy that prioritizes the use of the most accurate and granular data available, whether at the facility, transaction, company, region, or market level.
- **Relevance of retired RECs as demonstrating GHG-free imports** is a potential source of inaccuracy in the accounting of GHG emissions, introducing some of the same accounting challenges as discussed in Section II above in the context of energy supply mix disclosure programs. For the most part, mandatory GHG accounting and reduction programs do not allow the retirement of a REC to be used to offset reported emissions or comply with reduction mandates. The one place that RECs can sometimes be used is as a means to demonstrate that imported electricity has been received from an out-of-state renewable resource, and hence can be considered a GHG-free import (usually only if the REC is purchased along with energy in a renewables contract). Several of the utilities we interviewed expressed skepticism of the use of RECs even in this limited fashion, given that REC+energy purchases can be from far-away supply sources and with output profiles that may not align with system needs and import patterns in the physical system. To generalize the problem: RECs are a renewable production tracking product that is divorced from the economic and physical realities of reliability and transmission constraints that govern utilities' operational decisions (as well as the consequent GHG emissions from the dispatched power plants).
- **Conceptual basis of emissions rates for unspecified purchases** are also noted as a source of inaccuracy in GHG accounting. Presently, standard practice is to use a regulator-approved emissions rate for estimating emissions associated with market purchases, a rate that may be static or that may be updated on a regularized schedule. There are alternative conceptual frameworks that can be used to develop such a rate, such as based on a system average emissions rate in defined neighboring states

[59] See rules regarding the prevention of resource shuffling in California Air Resources Board, Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, pp. 118–122.

(as in the Nevada and Michigan supply mix disclosure programs); or based on the concept of the residual grid mix (as defined in the GHG Protocol above); or based on the expected marginal resource that will be dispatched to meet incremental demand (as in California, where a gas combine cycle plant is assumed marginal). Different approaches will produce different results, and in some cases could introduce substantial inaccuracies as compared to physical system outcomes. In the case of average grid mix, as noted by the GHG Protocol, this tends to produce lower GHG emissions than is accurate since the average mix incorporates non-emitting resources that are already claimed by others.

- **Static (rather than time- or location-varying) emissions rates for unspecified purchases** are the norm. Several utilities emphasized a problem that, for all participating entities other than the California Independent System Operator (CAISO), all imports from the EIM are allocated a static emissions rate of 0.428 or 0.437 tonnes/MWh, even though the physical marginal resource in the market varies widely by time and place.[60] One utility cited an example situation in which California's marginal resource could be curtailed solar resources, indicating that from both an economic and GHG perspective external Oregon and Washington utilities are displacing their own generation to import non-emitting resources. However, from a GHG accounting perspective, the Oregon or Washington utility would need to apply a gas combined cycle based GHG emissions rate for such purchases. Another utility expressed concerns related to the operations of its hydro and pumped hydro resources, resources it identifies as offering critical system energy balancing capabilities that will be needed to enable large volumes of renewables to be integrated without excess curtailment. Making the resources fully available for CAISO-EIM dispatch and scheduling would be likely to reduce system-wide GHG emissions substantially, but would also be likely to impose excess GHG obligations on the utility if all purchases through the EIM are measured with a static emissions rate.
- **Time granularity** is typically at the annual basis (though most utilities aggregate their annual reports from original data sources that may be more time-granular). For voluntary and informational accounting purposes, most utilities view annual granularity as acceptable for serving the intended purpose. Utilities engaged in mandatory reduction regimes moving toward a 100% GHG free tended to report that a more time-granular approach will eventually be needed, particularly as the physical realities of balancing cost, reliability, and remaining GHG emissions become acute. Several utilities reported consumer interest in increasing time-granular renewable offerings, such that utilities are actively considering or pursuing the necessary data tracking advances. As an example, one utility has expressed interest in developing time-granular matching of resources, demand, and net EIM transfers at the time-granular EIM emissions rate, but noted that the resulting GHG accounting may be used for both external customer and for internal company reporting, but at the present moment it may not be usable for state compliance accounting. Several states and the industry more broadly are pursuing other concepts for more time-granular GHG accounting, examples include California's ongoing docket investigating the feasibility of enhancing power source disclosures to be provided on an hourly basis; Federal Government procurements based on 100% net zero annual GHG emissions by 2030 of which 50% must be considered 24/7 supply; and Google's efforts to achieve 24/7 carbon-free energy.[61]
- **Resource deliverability associated with clean energy purchases** is not explicitly confirmed under current practice. The notion of deliverability is implicit via some states' accounting rules such as by requirements to utilize energy+REC wholesale contracts and calculating emissions rates based on neighboring states' averages. However, there are no mechanisms presently to ensure that the aggregate clean energy claims are individually or jointly deliverable to the retail service providers that

[60] Within CAISO footprint, the tracking of GHG emissions obligations under the cap-and-trade program is more granular in that generators that enroll under the GHG pricing regime can be dispatched to import into California to serve customers and compete against generators covered under the state-wide GHG emissions cap. Outside-of-California resources dispatched to serve California customers may then be subject to GHG emissions obligations under CARB's cap-and-trade regime, but are also eligible to earn a higher market price that reflects marginal embedded GHG emissions. Resources' GHG-free energy production under this CAISO dispatch model is not necessarily precluded from being separately claimed for in other states' or utilities' reporting programs however (e.g. if the asset is under contract with another entity or has sold RECs, but then also submits the resource for CAISO dispatch relative to the GHG-adjusted price).

[61] See California Energy Commission, "PSD Request for Information," March 11, 2023; The White House, "Executive Order on Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability," December 8, 2021; Google, "24/7 Carbon-Free Energy by 2030."

claim them as emissions-free imports. As in the case of time-granular tracking, some utilities anticipate that physical deliverability realities will produce inconsistencies between GHG emissions reported in accounting compared to remaining in-state fossil emissions, and that these inconsistencies will become greater as the utilities approach 100% targets.

- **Utility activities in the planning versus operating time horizons** incorporate GHG emissions in distinct ways that have the potential to produce inconsistent or unexpected outcomes. In the planning timeframe, utilities across all states are able to incorporate GHG limits into resource investment and retirement planning and assess anticipated cost tradeoffs; these tradeoffs can be considered against achievement of both mandatory and voluntary goals. However, in real-time operations only those resources that are explicitly subject to a regulatory cost of carbon or cap-and trade regime may be dispatched in ways that reflect a preference to avoid GHG emissions. For utilities without any explicit GHG emissions cost that can be considered in operations, resource dispatch in EIM, Midcontinent ISO, or through utility operations will prioritize the lowest-cost resources (including dispatching coal rather than gas plants, if coal prices happen to be even slightly lower on a $/MWh basis). For these utilities, the explicit or implicit willingness to pay to reduce GHG emissions as examined in the planning timeframe can disappear in real-time operations (relevant to their own resources) or become somewhat invisible (relevant to short-term bilateral and market purchases). One utility subject to a voluntary GHG reduction goal reported an example experience in which the company's annual Scope 1 emissions increased substantially when the interaction of gas and coal prices caused short-term dispatch to substantially increase output from its coal facility to serve off-system customers. For a utility in that situation, the primary strategy for reducing emissions may be to retire the coal plant (even though most planning models may identify coal-to-gas redispatch as a more cost-effective means to address the problem). The example raises a different issue when considered on a system-wide basis: the excess emissions from the coal facility in question were dispatched to serve customers somewhere across the broader market region, but the emissions have not been claimed by any of those customers given that unspecified purchases are tabulated at a lower rate similar to a gas combined cycle plant.
- **Each utility's position in the electricity supply chain** tended to affect their approach and prioritization of GHG accounting accuracy. Retail providers subject to mandatory and financially enforceable GHG reduction mandates are highly focused on accuracy and cost, and may require enhanced reporting from their out-of-state contractual counterparties. One downstream utility noted their desire to receive a more accurate contract-specific emissions rate, as in their particular situation the result would be lower than the counterparty's system-wide emissions rate. The more specific rates approach however, would impose greater burdens on the upstream generation utility to classify emissions across multiple buyers.
- **Interactions between GHG accounting and EIM and Extended Day-Ahead Market (EDAM) participation** arose in the majority of our interviews. The utilities tend to take a consensus view that increased participation in regional markets is needed or will be needed to manage reliability and cost, with the need growing alongside advances in renewable deployments across the West. However, GHG accounting practices do not yet align with the realities of real-time nodal dispatch and balancing. Financial accounting underpinning the CAISO, MISO, EIM, and EDAM does reflect these realities on a highly granular basis, including fully reflecting transmission constraints, ramping reserves, unit commitment timeframes, and 5-minute granularity of supply-demand dispatch and pricing. Overall, these financial accounting mechanisms ensure that customers pay the full costs of producing power dispatched on their behalf, and spot market prices can be settled against long-term contracts. No such system for reconciliation of GHG accounting obligations relative to short-term market dispatch realities presently exists. Aligning accounting and market operations may become critical to facilitating efficient market operations while demonstrating compliance with state emission policy and requirements.

- **Barriers to full participation in regional markets** were identified in a subset of our utility interviews as being related to GHG accounting challenges, primarily for utilities subject to mandatory reduction requirements. One set of barriers arises from the use of static emissions rates as applied to EIM or other organized market imports as described above. Under the current system, the risk of excess emissions obligations arising from EIM or organized market imports may incentivize utilities to avoid market purchases or remove hydro assets from full market participation. Utilities with efficient gas plants (outside of the cap-and-trade systems) may also be disincentivized against full market participation to avoid increases in their own Scope 1 direct emissions (even if the asset could more efficiently displace the GHG emissions from a different utility's coal plant). In the specific case of Washington's recently-implemented cap-and-trade market, utilities identified barriers to trade and poor liquidity in short-term bilateral markets that was attributed to accounting challenges and uncertainty in GHG prices and compliance obligations.[62] However, due to the early stages of the program, the utilities were unable to determine if the liquidity problems would be resolved relatively quickly as they gained experience or if the challenge would be persistent.
- **SEC climate disclosure rules** introduce a different suite of challenges from state programs. Many utilities with nascent voluntary GHG reporting are utilizing this rule as the catalyst to improve the accuracy of their accounting practices, given that the results will soon be subject to SEC oversight, potentially increased scrutiny from investors, and potentially enforcement actions. Utilities further noted that the need to improve, revise, or expand accounting practices will be amplified as end-use customers, contractual counterparties, parent companies, and lenders seek to conform to their own SEC disclosure obligations. Alignment across state and federal accounting guidance would reduce complexity and risks from inconsistent or inaccurate program rules.
- **Coordination across states, reporting entities, and programs** is limited for the purposes of GHG accounting (unlike in the context of RPS and REC tracking systems, where the regional WREGIS system is utilized across the West). In an ideal case, as envisioned in the GHG Protocol, self-consistent and simultaneously accurate GHG accounting concepts could be utilized across the West so as to ensure that all GHG emissions are allocated in a fair and consistent manner. However, in the present context no such system exists, meaning that inconsistencies may exist amongst programs and reporting entities that utilities must manage individually through requested policy changes as they arise. As one example of such a change, Washington's Department of Ecology has recently issued a rule clarification acknowledging that resources dispatched in Washington for the purpose of sales to California should not be subject to duplicate GHG emissions costs across the two states, and so resource owners have an opportunity to demonstrate such deliveries to address the disconnect.[63] However, the number and variety of similar challenges (examples of which are illustrated above) compound when considered across multiple jurisdictions with substantial levels of electricity trade. Several utilities expressed that a multi-state regional solution may be needed to address such inconsistencies or to simplify accounting practices.

V. Voluntary Utility and Consumer GHG Reporting and Commitments

Many utilities participate in voluntary GHG reporting or reduction commitments reflective of company, board, lender, customer, and economic drivers. Table 5 summarizes the voluntary actions that utilities interviewed have publicly committed to take on carbon-free energy supply and GHG emissions reduction. It also captures the reporting frameworks that companies use to develop, report on, and track progress

[62] Specifically, the bilateral transactions did not provide visibility into the underlying resource (and hence GHG emissions) that would be used to serve the transaction, and did not sufficiently clarify whether the buyer or seller would bear any emissions obligations associated with the trade. This challenge was compounded by the uncertainty in what GHG price should be expected given that no GHG allowance auctions had yet been held.

[63] Washington State Department of Ecology, Cap-and-Invest Guidance on Electricity Exports from Washington to California, January 2023.

of their initiatives. As discussed in Section I above, these programs are broadly aligned with and derived from the accounting principles laid out in the GHG Protocol.

Utilities with voluntary reporting activities range from large, multi-jurisdictional, and investor-owned utilities like Xcel Energy (Xcel), which owns and operates more than 20 GW of generating assets across 8 states, to small municipalities and public power entities including Platte River Power Authority (PRPA), which serves fewer than 200,000 retail customers. Some of these utilities have tracked their system-wide emissions for almost or more than a decade. As an example, Xcel has reported and undergone independent verification of its GHG emissions since 2005.[64] Similarly, Puget Sound Energy has voluntarily reported their carbon emissions since 2002, and ever since 2010 has submitted emission reports annually to the state of Washington.[65] Utilities with more historical experience tracking their emissions have highly-developed approaches to complex accounting issues, and in some cases have much larger teams of dedicated subject matter experts managing their accounting practices across several voluntary and mandatory programs. On the other hand, many of the smaller utilities, cooperatives, and municipalities have only recently begun efforts to develop emission inventories and may have limited resources that can be devoted. The number of utilities interested in developing new or refined GHG reporting practices is substantially expanding.

In our interviews, utilities expressed a variety of different motivations and contexts for their GHG accounting activities. We noted commonalities and differences as follows:

- **Reasons for reporting**. Utilities engage in voluntary reporting activities as a means of communicating with investors, member-owners, company leadership, board members, customers, and local communities. Though many of these same utilities also participate under state-required mandatory GHG reporting regimes as described above, additional voluntary reporting may be needed to align with the organizational and operational boundaries of the utility as a company in order to put GHG emissions in the context of the company's strategic positioning or risk exposures. Other utilities, such as public power entities serving communities that prioritize sustainability outcomes, focus their reporting efforts toward informing cost and environmental tradeoffs to their customers or communities. In other cases, the primary driver for providing voluntary GHG accounting information is in response to lender or parent company requirements that may also drive the chosen accounting framework and practices. Anticipation of mandatory SEC climate disclosure rules has expedited the activities of some utilities in order to gain experience before the first reporting deadline.
- **Reasons for making (or not making) voluntary commitments to reduce emissions**. Some utilities' voluntary commitments track closely to the mandatory GHG reduction requirements imposed by states. In other cases, utilities have adopted voluntary GHG reduction commitments as a strategy to maintain long-term company value in the context of existing and anticipated policies for clean energy transition, economic opportunities associated with cost declines in green supply, or in consideration of increasing local and customer demand for clean energy. Utilities that have not adopted a GHG reduction target report a primary focus on the delivered cost of energy to customers (which, in some cases is self-consistent with renewable resource development, particularly in regions with rich renewable resource potential or if RECs can be unbundled and sold to another party).
- **What reporting regimes are used.** As summarized in Table 5, the utilities we interviewed use a variety of reporting frameworks and standards, all of which can generally be described as consistent with the GHG Protocol. Though no one of these regimes emerged in our interviews as clearly superior or inferior, we did observe that the utilities are drawing heavily on the reporting guidance provided to improve accuracy and credibility of the results. The goals and roles of these programs are somewhat different as follows:

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64 Xcel Energy, *2021 Sustainability Report*, 2022, p. 10.

65 Puget Sound Energy, *2021 ESG Report*, 2022, p. 12.

- *GHG Protocol* is a foundational document laying out several foundational accounting principles (as described above in Section I), and that is used as a primary reference for several of the other regimes as well as the mandatory SEC disclosure rules;
- *Other voluntary reporting regimes* are cited by utilities as references or certification bodies used in their voluntary reporting including the Task Force on Climate-Related Financial Disclosures (TCDF), the Sustainability Accounting Standards Board (SASB), The Climate Registry (TCR), and Global Reporting Initiative (GRI) Standards;[66]
- *Edison Electric Institute (EEI) & American Gas Association (AGA)* reporting template that assists member electric and gas utilities to report a comparable set of metrics in a common database that can then be used by investors and others. End use customers may also use the customer template to estimate their own Scope 2 emissions obligations;[67] and
- *Customer-utilized reporting or goals regimes* were also discussed and have influenced some utilities' accounting efforts, even if the utility itself has not adopted the specific concepts advocated for under those regimes. Among these regimes include the Science Based Targets initiative (SBTi) that helps companies to formulate commitments in line with Paris Agreement goals, the Green-e initiative that seeks to give companies a higher value of confidence in the incremental GHG value of green energy projects, International Organization for Standardization (ISO) product lifecycle accounting standards that help companies communicate the sustainability impacts over the lifecycle of the products they create, and conduct aligned GHG accounting.[68]

- **Accounting practices**. Voluntary reporting programs are inherently flexible, such that utilities are able to align with the chosen reporting standard and then apply their own judgement on the most relevant methods or data. As a result, utilities are using somewhat different approaches in their voluntary reporting (see Section I above for a summary of the most commonly-used practices). The differences in resulting GHG emissions reported if compared across entities could vary substantially, for largely the same reasons described in Section IV in the context of mandatory reporting regimes. However, unlike with mandatory regimes, the utilities we interviewed are relatively less concerned by challenges with data granularity or consistency with other reporting entities. The utilities report that they are able to utilize the available flexibility to report the most meaningful metrics to their various audiences, assess the relative value of improved accuracy compared to the incremental resourcing costs, and can invest in additional granularity in accounting practices over time if the company deems that the incremental investment is merited.
- **How to support customers' reporting and data needs.** Our utility interviews revealed near-unanimous experience with requests for additional data or reporting in service of end-use customer or downstream delivery utilities' own reporting needs. End-use customers working in service of their own corporate sustainability goals may have different priorities for guiding their clean electricity or data reporting needs compared to what the utility would otherwise provide. Utilities report examples of customers seeking Green-e certified renewable supply, requesting more detail on their own customer-specific emissions rates, or providing data or other supports needed to align with new 24×7 accounting and carbon-free electricity supply goals. Several utilities reported similar customer inquiries as driving the need for expanded reporting and/or expanded customer green energy programs. However, as a counterexample, at least one utility in a state with near-term deep decarbonization mandates speculated that customer sustainability goals will become less impactful as the system catches up to even the most ambitious private customer goals. The role of RECs in GHG reporting we noted as an area of concern for both customers and utilities (though for different

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66 See Task Force on Climate-Related Financial Disclosures, *Recommendations of the Task Force on Climate-related Financial Disclosures*, June 2017; Global Reporting Initiative, "Standards"; Sustainability Accounting Standards Board, "Standards Overview"; and The Climate Registry, "Registries and Resources."

67 EEI, Finance & Tax, ESG Sustainability.

68 See Science Based Targets initiative "Resources"; Green-e, "Verification Reports."

reasons). As discussed above, most utilities we interviewed view RECs as an inaccurate or inappropriate tool for GHG accounting, but are regardless widely used to support consumer green tariffs given that they remain the primary tool available for that purpose. Customers increasingly may request a next generation of GHG-abatement-aligned RECs or similar instruments, such as those advocated for by the Clean Energy Buyers Institute (CEBI).[69] This growing area of customer demand for additional instruments, tools, and data is in the early stages of development and deployment.

Overall, voluntary reporting programs are an area of great interest and innovation among the utilities we interviewed (as well as their customers). However, while accounting practices vary as widely as in the mandatory programs, the financial consequences of any inconsistencies or errors are limited by the fact that utilities have the flexibility to correct any identified problems, customize reporting to their own needs, and make improvements over time.

[69] See for example, Clean Energy Buyers Institute, "Next Generation Carbon-Free Electricity Procurement Initiative."

TABLE 5: VOLUNTARY UTILITY GHG REPORTS AND SUSTAINABILITY COMMITMENTS

Utility	Current Report(s)	Voluntary Commitments	Reporting Regime or Standard(s)
Avista	• 2022 Corporate Responsibility Report	• 2027: Carbon-neutral supply of electricity • 2045: 100% clean electricity	• EEI/AGA reporting template • TCFD guidance • SASB
Basin Electric	• 2022 Sustainability Report	• n/a	• Not specified
Bonneville Power Administration	• BPA 2018–2023 Strategic Plan • Sustainability Metrics	• n/a	• Not specified
Eugene Water & Electric Board	• 2019 Operational GHG Inventory • 2021 and 2022 Operational GHG Inventory • SD15 Climate Change Policy	• 2020: 25% reduction in Scope 1 & 2 emissions • 2030: 95% carbon-free retail electricity; 50% reduction in Scope 1 & 2 emissions • 2050: Achieve carbon neutral operations	• GHG Protocol • The Climate Registry Electric Power Sector Protocol
Montana-Dakota Utilities	• 2021 Sustainability Report	• 2030: 45% reduction in CO_2 emissions	• EEI/AGA reporting template • TCFD guidance
NV Energy	• 2020 Corporate Sustainability Report • 2019 NV Energy Sustainability Report	• 2050: Net-zero electricity (Berkshire Hathaway)	• EEI/AGA reporting template
PacifiCorp	• 2021 PacifiCorp GHG Emission Data	• 2050: Net-zero electricity (Berkshire Hathaway)	• EEI/AGA reporting template
Platte River Power Authority	• Resource Diversification Policy	• 2030: 100% carbon-free resource mix	• Not specified
Portland General Electric	• 2021 ESG Report	• 2030: 80% reduction in emissions • 2035: 90% reduction in emissions • 2040: 100% carbon-free electricity	• GHG Protocol • EEI/AGA reporting template • TCFD • SASB
Puget Sound Energy	• 2022 ESG Report • Pathway to Beyond Net Zero Carbon by 2045	• 2030: Carbon-neutral supply of electricity • 2045: 100% carbon-free electricity	• EEI/AGA reporting template • TCFD • SASB
Salt River Project	• SRP 2035 Sustainability Goals • SRP 2021 Sustainability Report	• 2035: 65% reduction in CO_2 emission rate • 2050: 90% reduction in CO_2 emission rate	• The Climate Registry • GHG Protocol
Tacoma Power	• 2021 Annual Report	• Consistent with state mandates	• Not specified
Tucson Electric Power (TEP)	• 2022 Sustainability Report (Fortis) • Operating company sustainability reporting for TEP and parent company UNS Energy	• 2030: 50% reduction in Scope 1 emissions (Fortis) • 2035: 80% reduction in CO_2 (TEP); 75% reduction in Scope 1 emissions (Fortis) • 2050: net-zero (Fortis)	• EEI/AGA reporting template • SASB (Fortis) • TCFD (Fortis) • GRI (Fortis)
Xcel Energy	• 2021 Sustainability Report	• 2030: 80% reduction in CO_2 emissions by 2030 • 2050: 100% carbon-free electricity	• EEI/AGA reporting template • The Climate Registry • GRI Standard • TCFD • SASB

VI. Discussion of Identified Themes

We identified several common themes across these utility interviews.

THEME 1: DUE TO THE VARIETY OF STATE POLICIES AND VOLUNTARY PROTOCOLS, THERE IS NO COMMON, FIT-FOR-PURPOSE GHG EMISSIONS ACCOUNTING METHODOLOGY AND DATA TRACKING SYSTEM FOR THE WEST

No coordinated system exists for the purpose of tracking regionally accurate and self-consistent GHG emissions or emissions associated with electricity trade.

Utilities in the West are reporting GHG emissions and clean energy under at least 56 distinct programs, each with distinct policy goals and accounting methods. The differences across programs range from minor issues of accuracy, to considered differences in program objectives, to material unintended consistencies. The situations in which GHG accounting differences present the most challenges to utilities are those cases in which some or all of the following conditions apply: (a) the GHG accounting methods chosen will result in substantially different outcomes in terms of resource mix, resource dispatch, deemed GHG emissions obligations, and customer cost; (b) the GHG accounting is conducted in the context of a mandatory and enforceable policy goal; and/or (c) the ability of the state or utility to meet its policy objective reliably and at a reasonable cost is substantially impacted by the ability to buy and sell energy across state borders and across company boundaries. In these cases, the lack of a self-consistent region-wide GHG accounting methodology or tracking system may reduce visibility on the level of progress toward the stated goal, impose excess costs on utilities and customers to meet the policy goal, limit the pace of progress, or create barriers to full participation in regional power markets.

For utilities and states facing these challenges, there may be opportunities for regional coordination and cooperation through a fit-for-purpose regional GHG tracking system or accounting methodology. Such a system would ideally seek to align with and mutually support bilateral contracting, market participation, and visibility into progress on policy goals.

THEME 2: WHEN ACCURATE GHG EMISSIONS DATA ARE NOT AVAILABLE, A VARIETY OF ACCOUNTING PRACTICES ARE USED TO ESTIMATE SCOPE 2 AND SCOPE 3 EMISSIONS

Utilities are able to conduct accurate reporting of their own GHG emissions associated with assets under their direct ownership or control (i.e., for Scope 1 emissions).

However, utilities, states, and customers engage in extensive levels of trade across the power grid and in ways that cross organizational and jurisdictional boundaries, each transaction of which notionally incorporates a Scope 2 or 3 GHG obligation.[70] Utilities and policymakers must account for the GHG emissions embedded within or avoided by this trading activity if they are to develop robust polices and GHG abatement strategies. Given that granular and transaction-specific GHG tracking data are not readily available, utilities and policymakers have adopted a number of alternative approaches for approximating emissions obligations, such as using average or marginal emissions rates for unspecified purchases and implementing accounting on an annual average basis. These annual averages may not capture the GHG emissions associated with power generation resources dispatched to serve daily consumption patterns and seasonal peak electricity demands. Additionally, when accounting is based on contractual pathways rather than the physical path of the electricity flows, there may be patterns of resource dispatch and transmission limitations that are not fully captured.

[70] These GHG emissions embedded in electricity trade should ultimately be reported as Scope 2 emissions for the end use consumer (i.e. GHG emissions associated with their electricity consumption), and Scope 3 emissions for the utility (i.e., GHG emissions associated with market purchases that are ultimately resold to end use consumers). See Section I: Background for additional discussion.

THEME 3: THE VARIETY OF ACCOUNTING PRACTICES AND DATA SOURCES IN USE ACROSS THE WEST CAN LEAD TO INCONSISTENCIES OR DIFFERENCES IN ESTIMATED GHG EMISSIONS DEVELOPED BY DIFFERENT ORGANIZATIONS AND UNDER DIFFERENT PROGRAMS

Western states have chosen to implement a variety of different GHG accounting methods and policies which can produce different results. These differences in accounting methods are not necessarily a problem if they are intentional and reflect distinct policy goals across different states and organizations.

However, unintentional differences tend to arise for states and companies whose clean electricity goals are materially affected by the emissions associated with power purchases and sales. In these cases, an approach must be selected for claiming or allocating responsibility for GHG emissions, and that allocation of responsibility may cross state borders and organizational boundaries. If different accounting methods are used by different states and companies, the outcome in aggregate across all parties will introduce one or more of the following problems: (a) to artificially inflate the estimated GHG emissions obligations assigned to specific customer segments; (b) to inaccurately remove some GHG emissions from consideration so that they are assigned to no customers; or (c) assign GHG emission obligations to the wrong customers. None of these unintended outcomes are desirable from a broader policy, regulatory, economic, or equity perspective.

In some cases, the potential impact of such differences may be deemed as small or acceptable given the context or program goals. For example, voluntary reporting programs tend to offer substantial flexibility that is needed to consider emissions that are material to an organization's unique operations, and in order to mitigate the costs of participating.

However, mandatory reduction and reporting programs should aim to minimize the potential for cross-state and cross-organization misalignment if the scale of inconsistencies could drive excess costs or undermine policy objectives. In these cases, the affected states and utilities may wish to pursue consistency in measuring the aggregate quantity of emissions accounted for across state and utility boundaries, as well as consistency in allocating emissions responsibility. Achieving that objective may require the participating entities to adopt a common GHG accounting methodology or tracking system to prevent emissions obligations from being artificially inflated, underestimated, or wrongly assigned. Further, ongoing efforts to expand organized power markets across the West could offer more opportunities for coordination if they consider policy scope, utility reporting needs, and end use customers' use cases for GHG tracking and accounting. If expanded markets in the West can support, align with, and accommodate different parties' GHG accounting needs, there would be opportunities to expand the economic and policy benefits of the regional power markets.

THEME 4: JURISDICTIONAL POLICY FRAMEWORKS FOR GHG ACCOUNTING ARE NOT CONSISTENT WITH THE PHYSICAL FLOW OF ELECTRICITY ACROSS BROAD GEOGRAPHIES, ELECTRIC SYSTEM OPERATIONAL CONSTRAINTS, AND CURRENT MARKET STRUCTURES

As more states adopt clean energy policies, there is a growing divergence between the jurisdictional boundaries of those policies and the physical realities of the multi-jurisdictional electric transmission systems and regional power markets. States' clean energy policies and associated enforcement mechanisms may need to become increasingly sophisticated if they are to fully reflect the physically and financially interconnected nature of the power grid. Similarly, power markets may need to increasingly acknowledge and reflect states' and utilities' need to meet and demonstrate achievement of GHG emissions goals across a regionally interconnected system.

The West is further comprised of regions with substantial geographic differences in policy goals, resource mix, and resource potential. These differences range from Northwestern utilities with hydropower-rich systems to Southwestern utilities relying primarily on nuclear and gas plants. These differences mean that each state and utility faces a unique combination of reliability needs and economic-policy tradeoffs; and a range of opportunities to benefit from trade and mutual support.

THEME 5: MORE ACCURATE EMISSIONS RATES ASSOCIATED WITH "UNSPECIFIED" AND WHOLESALE MARKET PURCHASES CAN ENHANCE TRADE AND FULL PARTICIPATION IN REGIONAL MARKETS

Utilities and policymakers increasingly acknowledge the need to engage in greater levels of trade in regional markets in order to maintain reliability in a cost-effective manner throughout the clean energy transition. Accessing the full benefits of system flexibility and diversity will be necessary, and will produce expanded levels of trade as utilities must manage increasing system balancing needs in renewable-rich systems. The granularity and flexibility offered through regional market participation is not yet aligned with static emissions rates that are typically used for measuring emissions associated with market purchases (or net GHG obligations associated with net market purchases).

In voluntary or informational reporting regimes, the implication is reduced accuracy. However, in mandatory GHG reduction regimes, the implication of inaccuracy can in some instances be to impose excess GHG obligations and associated costs on utilities and customers. Development of more refined and dynamic estimates for such emissions rates could reduce the potential for such outcomes and may incentivize fuller participation in regional EIM and EDAM markets.

THEME 6: WITH THE INCREASE IN FINANCIALLY ENFORCEABLE MANDATES, GHG ACCOUNTING PRACTICES HAVE THE POTENTIAL TO INTRODUCE RISKS AND COSTS TO UTILITIES AND CONSUMERS

The consequences of using estimated or proxy values for GHG accounting have historically been somewhat limited due to the informational or voluntary nature of reporting programs. Increasingly, GHG accounting is tied to financially impactful outcomes as under mandatory GHG reduction programs. Ensuring that GHG emissions data reports are meaningful and accurate will become increasingly important if the associated programs are to serve policy goals, manage costs, and produce equitable outcomes. Even outside of mandatory GHG reduction programs, the introduction of mandatory SEC disclosures amplifies the importance of accuracy to utilities and costumers, given the risks that could be introduced by inaccurate investor disclosures.

THEME 7: A UTILITY'S POSITION IN THE VALUE CHAIN CAN SUBSTANTIALLY IMPACT THE NATURE OF AVAILABLE DATA AND DATA SHARING NEEDS WITH CONTRACTUAL COUNTERPARTIES

The level of concern and importance placed on the accuracy of GHG accounting is affected by each utility's regulatory context and position in the value chain. A utility that is subject to mandatory GHG reporting and reductions will place greater value on accurate emissions data, particularly when more accurate accounting can confirm lower-emitting sources of supply and reduce compliance costs. Upstream entities that are not subject to mandatory programs may place less emphasis on granular accounting of which resources' emissions should be attributed to any one customer or contractual counterparty. For both upstream and downstream utilities, the accuracy of GHG tracking is limited by the current state of time and location matching tools for market transactions.

Further, under current guidelines, sustainability-oriented buyers' and customers' reporting may combine in aggregate to leave a gap in emissions accounting associated with wholesale purchases. For example, buyers and sellers alike are able to claim low-emissions sources associated with specific contracts, while accepting a gas-plant-based rate for unspecified market purchases. However, net market sales can sometimes include higher-emitting resources such as coal plants that may not be allocated to any customers. Because there is no ex post reconciliation across reporting entities, unclear or flexible reporting guidance may sometimes produce under-reporting in aggregate that each company is individually aiming to avoid.

THEME 8: UTILITIES REPORT INCREASING DEMAND FOR TRANSPARENCY AND GRANULARITY IN GHG AND CLEAN ENERGY ACCOUNTING FROM COMPANY BOARDS, END USE CONSUMERS, INDUSTRY ADVOCACY ORGANIZATIONS, AND LENDERS

For a variety of policy-driven, customer-driven, and company-driven reasons, utilities are expanding their GHG accounting efforts to support more use cases and improve accuracy. Customers increasingly wish to understand their own GHG footprint in a more detailed fashion and seek to displace those emissions through innovative service offerings. Utilities anticipate the need for enhanced accounting practices that can more meaningfully reflect GHG causation, including accounting for the realities of transmission constraints, reliability needs, and balancing throughout clean energy transition. The technology tools, regulatory frameworks, and market practices that will be needed to meet this growing demand are only just beginning to emerge.

Increasingly, states, utilities, and consumers that seek to pursue and demonstrate achievement of GHG abatement goals will need increasingly accurate methods for tracking non-emitting power and residual GHG obligations. Opportunities for increased regional collaboration may improve the ability to measure GHG emissions using consistent methodologies, particularly as associated with trade between companies, via regional markets, and across state borders.

List of Acronyms

AGA	American Gas Association
CAISO	California Independent System Operator
CARB	California Air Resources board
CDP	Carbon Disclosure Project
CEC	California Energy Commission
CES	Clean Energy Standard
CO_2	Carbon Dioxide
EDAM	Extended Day-Ahead Market
EEI	Edison Electric Institute
eGRID	Emissions & Generation Resource Integrated Database
EIM	Energy Imbalance Market
EPA	Environmental Protection Agency
ESG	Environmental, Social, and Corporate Governance
GHG	Greenhouse Gas
GW	Gigawatt
M-RETS	Midwest Renewable Energy Tracking System
MWh	Megawatt Hour
PGE	Portland General Electric
REC	Renewable Energy Certificate
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SASB	Sustainability Accounting Standards Board
SEC	Security and Exchange Commission
SF6	Sulfur Hexafluoride
T&D	Transmission and Distribution
TCFD	Task Force on Climate-Related Financial Disclosures
tCO_2e	Tonnes (t) of Carbon Dioxide (CO_2) Equivalent (e)
TCR	The Climate Registry
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System
WRI	World Resources Institute