Fueling the Transition:
Categorizing emissions-reducing oil and gas projects according to Canada's climate investment taxonomy

By Jonathan Arnold

Acknowledgment

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While this report is a product of the Canadian Climate Institute, we actively engaged with a diverse group of experts to shape the research and conclusions. We want to acknowledge the valuable insights provided by the Oil and Gas Working Group, which was established by CCI to help inform the research and analysis in this paper (listed in Appendix). We also want to acknowledge the other 30+ stakeholders and rights holders that offered their time and insights, representing industry, finance, ratings agencies, regulators, Indigenous communities and Nations, and environmental non-profits. In addition, the SFAC Taxonomy Technical Expert Group, and several of its financial industry members, played a vital role in reviewing and contributing knowledge and expertise to this project.

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Executive Summary

In March 2023, the federally appointed Sustainable Finance Action Council—comprising representatives of Canada's 25 largest financial institutions—recommended that Canadian governments establish a Climate Investment Taxonomy. In effect, the taxonomy would serve as a standardized framework to help financial markets assess which projects and investments can help reduce fossil fuel emissions from hard-to-decarbonize sectors in line with Canada's climate goals.

The proposed taxonomy framework is a direct response to the accelerating race to attract global capital on the pathway to net zero and the need to shore up the country's competitiveness in the transition. Canada needs to increase private and public investments in clean growth projects by $80 to $110 billion annually to meet the country's climate targets. Taxonomies are effective tools for mobilizing private capital while simultaneously reducing the risk of greenwashing in financial markets, where misinformation and a lack of standardization around climate commitments are rife.

A big part of the SFAC taxonomy framework is about defining "green" investments and projects. Almost all of the 30+ countries that have developed or are developing taxonomies focus on defining this green label. It typically includes activities and projects that are already aligned with a net zero future, such as renewable electricity, batteries and storage, electric vehicles, and low-carbon hydrogen. Here, the approach recommended by SFAC is to mirror frameworks and leading practices from elsewhere, such as the European Union.

The SFAC taxonomy framework also establishes a "transition" category, which few other taxonomies cover. This label is intended to identify, and unlock funding for, credible pathways to rapidly decarbonize Canada's emissions-intensive sectors, such as iron and steel, aluminum, cement, and chemicals manufacturing. Transforming these historically dirty sources of economic growth is critical to reducing the pollution that causes climate change in line with national and international climate commitments while also ensuring that these sectors remain competitive through the clean energy transition. The current market for transition-labelled bonds and loans is virtually non-existent in Canada, so this additional label is intended to create new financing mechanisms for these hard-to-abate sectors to attract the investment needed to accelerate their decarbonization.

Perhaps controversially, the proposed framework considers the oil and gas sector to be one of these hard-to-abate sectors, setting out criteria by which oil and gas projects could become eligible for the taxonomy's transition label.

The idea of considering *any* oil and gas activities in the taxonomy raises legitimate concerns about preserving the taxonomy's credibility. Climate science is clear that the production and consumption of fossil fuels must decrease significantly and rapidly if the world is to keep global average temperature rise to below 1.5°C. The upstream production of oil and gas in Canada accounts for more than one-quarter of the country's total greenhouse gas emissions. When downstream emissions are considered, or the combustion emissions from fossil fuels produced in Canada and exported abroad, the oil and gas sector's emissions are equivalent to 125 per cent of the country's entire annual emissions.[1] And whereas other heavy-emitting sectors have made progress in reducing emissions, oil and gas emissions remain stubbornly high.

Yet it is exactly because of the oil and gas sector's high emissions profile that it is essential to evaluate oil and gas decarbonization projects based on the criteria outlined in the taxonomy. Even as global demand begins to shrink this decade, large-scale investments to decarbonize the upstream production of oil and gas will be necessary to achieve Canada's climate targets and maintain competitiveness of its industries. These investments can help industry comply with increasingly stringent climate policies targeted at reducing the sector's emissions, such as industrial carbon pricing, methane regulations, and the forthcoming emissions cap on oil and gas emissions. The investments can also help Canada generate low-carbon energy, thereby reducing the risks of future compliance costs, meeting global expectations, and preserving Canada's competitive edge in the energy sector.

This paper offers a starting point for balancing these competing tensions and provides a framework for what a credible, and science-based taxonomy could look like for assessing oil and gas decarbonization projects as potentially transition-compliant. For Canada to maintain credibility in global capital markets, this proposed framework necessarily sets a high bar for industry, using detailed metrics that can identify transformative decarbonization investments that align with 1.5°C pathways from those that do not. At the same time, the framework must be practical and straightforward for financial markets to use.

This paper builds on the taxonomy framework proposed in SFAC's *Taxonomy Roadmap Report*. The SFAC framework includes three sets of eligibility requirements:

1. **General requirements** at the corporate level that require users of the taxonomy to have credible, science-based net zero targets, detailed transition plans that outline how these targets will be met, and adherence to leading practices in climate-related disclosures.

2. **Specific requirements** at the project level that determine whether a specific project qualifies for the "green" or "transition" label;

3. **Do-no-significant-harm requirements** at the project level that provide minimum safeguards against other important objectives, such as adaptation, Indigenous rights and reconciliation, and other environmental impacts (e.g., biodiversity, water and air pollution).

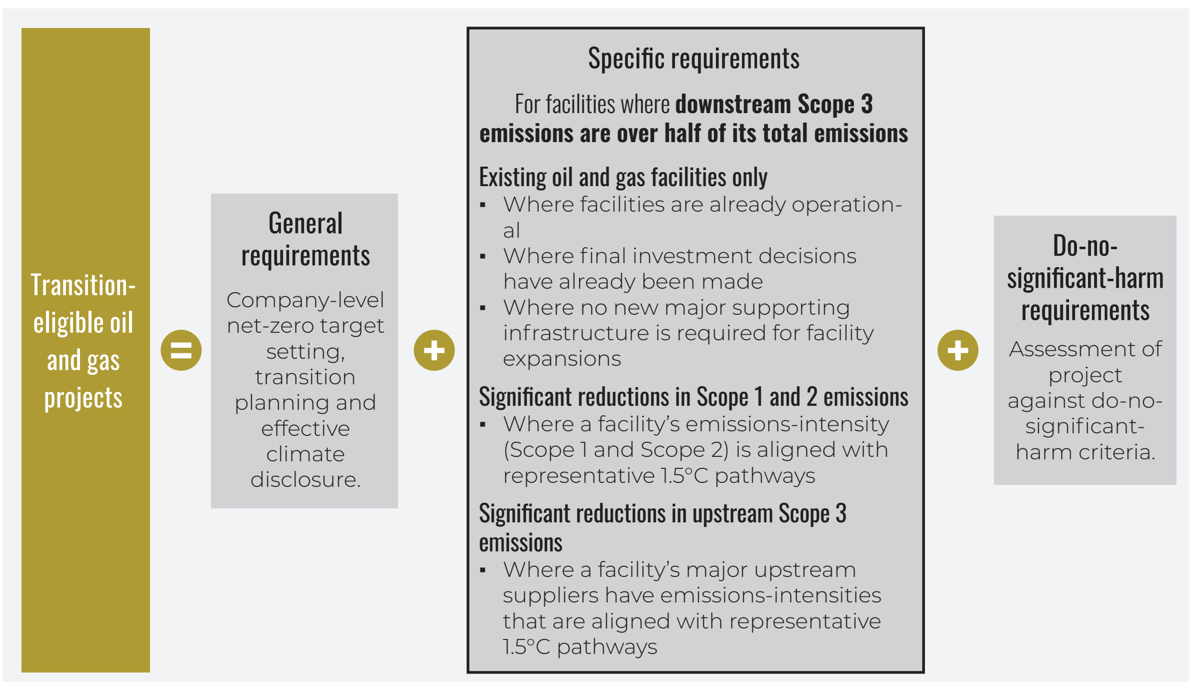
1 This was an environmental petition by Ecojustice. So even though the URL takes you to an Ecojustice page, the estimates are from the Government's response to the petition.

This paper focuses exclusively on defining the **specific requirements** for oil and gas projects under the taxonomy's "transition" label. In other words, we assume that the issuer or user of the taxonomy has already met the general requirements under the taxonomy, which ensure that companies have set credible, science-based net zero emissions targets and strategies for managing transition risk across their facilities. Individual projects defined under the specific requirements would fit into a company's larger transition strategy. Similarly, we also assume a project meets the do-no-significant-harm criteria, which are also beyond the scope of this report.

Figure 1 below summarizes the specific requirements proposed in this paper. We start by defining oil and gas projects for the purposes of the taxonomy. Given that the oil and gas sector faces disproportionately higher transition risk than other sectors—due to declining global demand for fossil fuels in the transition—our definition focuses on a project's downstream Scope 3 emissions.[2] Specifically, we propose a lifecycle emissions threshold, where if more than 50 per cent of a project's lifecycle emissions are from the downstream use (or combustion) of the product, it is considered an oil and gas project under the taxonomy. This proposed definition would capture almost all types of oil and gas projects, along with traditional automotive manufacturing facilities that build cars that run on fossil fuels.

Figure 1:

Specific requirements to be eligible for the transition label



2 Scope 1 greenhouse gas emissions are those emitted within the physical boundaries of the project. Scope 2 emissions are emissions generated from energy (typically electricity) used by the project. Scope 3 emissions include those generated upstream from the project (excluding Scope 2 emissions), as well as the emissions generated downstream from the project.

All other projects that fall below this 50 per cent threshold would be treated differently under the taxonomy framework and will be covered in subsequent research. These projects would include any that are eligible for the taxonomy's green label, such as renewable energy and batteries and storage, in addition to other emissions-intensive sectors that could become eligible for the taxonomy's transition label. Importantly, they could also include select projects that are traditionally considered to be within the oil and gas sector but that fall below the threshold. Facilities that manufacture hydrogen using fossil gas, and that capture and permanently sequester the facility's emissions, may, for example, fall under the 50 per cent threshold. These types of projects and their eligibility criteria will be explored in future research.

Under the definition summarized in Figure 1, oil and gas projects would need to meet three criteria to become eligible for the taxonomy's transition label.

The first is to ensure that the decarbonization project getting financed under the taxonomy is part of an *existing* oil and gas facility. This reflects the growing international consensus that keeping global temperatures below 1.5°C degrees requires no new oil and gas developments—a principle that was reflected in the SFAC Taxonomy Roadmap.

To put this principle into practice, we propose a definition that differentiates between oil sands facilities and conventional oil and gas facilities. Each type of facility would need to satisfy the criteria in Table 1 to be considered *existing*.

Table 1:

Defining **existing** oil and gas facilities — oil sands or conventional

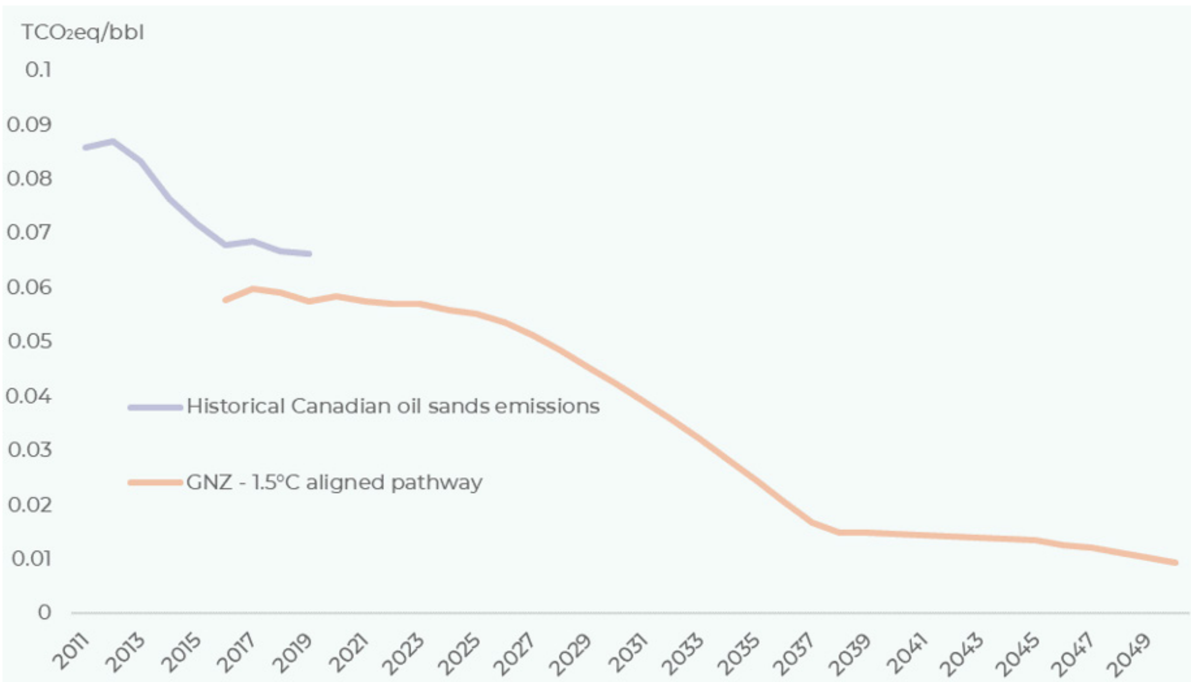
Existing oil sands facilities	Existing conventional oil and gas facilities
▸ A field where extraction and production are already taking place; AND, ▸ Where capital funds have already been committed and implementation of the development project or mining operation is underway (where a final investment decision was made by a specified date); AND, ▸ Where any facility expansions (if relevant) do not require new major infrastructure (e.g., gathering lines, processing facilities, upgraders, etc.)	▸ A field where extraction and production are already taking place; AND, ▸ Where any new pads and wells do not require new major infrastructure (e.g., gathering lines, processing facilities, upgraders, etc.)

This proposed definition builds on and leverages pre-existing definitions and standards used internationally, such as the United Nations and the International Energy Agency. For oil sands facilities, we propose using the status of final investment decisions as the primary indicator. And recognizing that existing oil sands facilities have the potential to expand beyond what is compatible under 1.5°C degrees, we also propose an additional criterion around supporting infrastructure for the expansion. For conventional oil and gas facilities, where final investment decisions are less common, we propose using similar criteria on the extent to which a facility requires new supporting infrastructure, such as gathering lines and processing facilities.

The second criterion requires that facilities reduce their Scope 1 and 2 emissions to a level that meets or falls below a sectoral emissions-intensity benchmark. Setting this precise benchmark is beyond the scope of this paper; however, the taxonomy could use data from the Canada Energy Regulator, for example, which shows the emissions intensity that Canadian producers need to achieve to align with a 1.5°C pathway. We illustrate this idea in Figure 2, showing the historical emissions intensity of Canadian oil sands production with a trajectory consistent with a 1.5°C pathway.

Figure 2:

Canadian oil sands emissions intensity vs. 1.5°C GNZ pathway



Source: Canada Energy Regulator (Global Net Zero Sectoral Benchmark) and Alberta Energy Regulator (Alberta Oil Sands Greenhouse Gas Emissions Intensity Analysis)

The third and final criterion requires that a facility's major upstream suppliers (Scope 3) are also aligned with 1.5°C degree pathways. This criterion is particularly important for midstream or downstream oil and gas facilities that often have high upstream Scope 3 emissions. But it is also clear that requiring an issuer to demonstrate that *all* of its upstream suppliers are aligned with 1.5°C pathways is too cumbersome to implement. As such, this criterion would only apply to the upstream suppliers of fossil fuels for a given project. For example, a liquified natural gas facility looking to receive a transition label would need to ensure that its upstream supplier of natural gas meets the definition of "existing" under the taxonomy and is making significant emissions reductions within their own operations.

Taken as a package, the proposed criteria and thresholds outlined in this paper set a high bar for determining what oil and gas projects could qualify for the taxonomy's transition label. The production and consumption of fossil fuels is the biggest source of greenhouse gas emissions globally and is the primary driver of climate change. Achieving the 1.5°C target in the Paris Agreement requires a significant and sharp decline in the consumption of fossil fuels globally, but it also requires a dramatic reduction in the emissions associated with how fossil fuels are produced, particularly in the short to medium term.

Within this context, Canada needs a taxonomy that can help drive transformational investments in decarbonizing the oil and gas sector while it guards against locking in emissions from new fossil fuel projects. Striking this balance will not be easy; however, this paper lays out a potential path that can help Canada both meet its climate goals and keep the country competitive in a low-carbon world.

Section 1: Context Setting

This section situates the specific questions related to oil and gas within the broader SFAC taxonomy framework. It provides a working definition of what a *project* means within the context of the taxonomy, and assesses how projects financed under the taxonomy may fit within the physical boundaries of individual oil and gas facilities. It discusses how, for the case of oil and gas, taxonomy financing may only go toward a project within a facility that actively reduces emissions and not toward the facility's general capital and operating expenditures.

Box 1: Taxonomy 101

Taxonomies are a classification system. Like other taxonomies that codify and label individual parts of complex systems, sustainable finance taxonomies create a standardized framework—in this case to help financial markets assess whether specific projects and investments are genuinely aligned with sustainability goals.

The fundamental role of sustainable finance taxonomies is to create the market clarity and integrity necessary to spur and accelerate capital investment into sustainable assets and projects. By improving information available to market participants, they create the confidence and transparency that investors need to make better decisions in line with their investment strategies. In doing so, taxonomies play an important role in reducing greenwashing risk and the misallocation of capital toward projects that lock-in emissions, making it harder or more expensive to reduce emissions in the future.

The taxonomy proposed by SFAC in March 2023 introduced two labels to help standardize climate finance in Canada: *green* and *transition*. As illustrated in the figure below, the green label would apply to projects that are directly aligned with a net-zero future, such as wind and solar, electric vehicles, clean hydrogen, afforestation projects, and electricity transmission infrastructure.

The transition label would be reserved for projects that would lead to significant emissions reductions across facilities from high-polluting sectors, such as steel, cement, aluminum, chemicals, and oil and gas. This paper focuses exclusively on how—and under what conditions—oil and gas projects might be eligible for the "transition" label.

Higher transition risk, less opportunity ← → Lower transition risk, higher opportunity

Excluded activities	Transition activities	Green activities
Embody high stranded asset risk, promote carbon lock-in, and are unaligned with transition pathway. Sectors without significant emissions or those not materially affected by transition.	Decarbonizing emission-intensive activities critical for sectoral transformation, consistent with a net-zero, 1.5 °C transition pathway (e.g., electric furnaces to produce steel).	Low or zero-emitting activities (e.g., solar and wind) or those that enable them (e.g., hydrogen pipelines.)

Importantly, SFAC's proposed taxonomy framework is voluntary. It would not dictate what investors can or cannot invest in.

Notably, all of the research and analysis in this document takes the assumptions from the SFAC Taxonomy Roadmap report as given (see Box 1). For example, the thresholds and metrics proposed are designed to be consistent with keeping the rise in global temperatures to below 1.5°C (relative to pre-industrial levels). This serves as the benchmark to evaluate the conditions for which oil and gas sector activities may become eligible for transition-labelled financing.

The proposed SFAC taxonomy framework includes a three-step process to become eligible for the green or transition label

The SFAC framework lays out three sets of requirements for eligibility based on emerging best practices internationally. The first is a set of general requirements at the issuer or corporate level. As described in the SFAC Taxonomy Roadmap Report, these general requirements would ensure that issuers have set a credible and science-based target to align their business activities with 1.5°C degree scenarios by 2050. This would include setting a 2030 target and at least one interim target between 2030 and 2050. They would also require issuers to develop preliminary net-zero transition plans that are comprehensive and science-based within 12 months of the issuance, and a comprehensive science-based net-zero transition plan within 24 months. Finally, issuers would need to follow emerging best practices in climate-related disclosure, including those recommended by the International Sustainability Standards Board.

These general requirements play an essential role in the framework, acting as a pre-filter on whether specific projects may be eligible for taxonomy-labelled financing. In this sense, they are a critical first step to safeguard the taxonomy's scientific integrity and closely inform the project-level requirements discussed next. They ensure that taxonomy-aligned issuers and corporations have high-level strategies for managing transition risk across their facilities, and that they understand how individual projects fit into an organization's overarching strategy to align with 1.5°C degree pathways.

After an issuer has demonstrated compliance with the general requirements, the second set of requirements—and the primary focus of this paper—is about determining whether a specific project qualifies for a "green" or "transition" label. This step in the framework requires the Taxonomy Council and Custodian to set clear thresholds and criteria for how and under what conditions specific projects might qualify for taxonomy financing.[3] The remainder of this paper lays out what such criteria and thresholds could look like for oil and gas projects.

The final step to evaluate taxonomy eligibility involves assessing each project against a set of do-no-significant-harm criteria. These are binary criteria: if a project or facility violates any one of these criteria, it would be ineligible under the taxonomy. For example, a project categorized as "green" that also causes significant (non-climate) environmental damage would be ineligible. Like the specific requirements described above, the do-no-significant-harm criteria for the Canadian taxonomy would ultimately need to be determined by the Taxonomy Council and Custodian.

While the do-no-significant-harm requirements are beyond the scope of this paper, they could have important implications for oil and gas projects and should be assessed in greater detail in future research. Environmental risks and impacts associated with oil and gas development in Canada are significant, including pollution (water, air, soil), impacts to biodiversity and species at risk, displacement of Indigenous communities, and billions of dollars worth of unfunded cleanup obligations from industry.

The taxonomy is designed to accelerate the development of green and transition projects

The goal of the taxonomy is to accelerate capital flows to projects with low or zero emissions (e.g., wind or solar farms, battery manufacturing plants, etc.) as well as to projects that help decarbonize emissions-intensive facilities (e.g., steel and aluminum manufacturers) to align them with 1.5°C degree pathways.

Clearly defining what constitutes a *project* is therefore critical to operationalizing the taxonomy. Drawing clear boundaries is particularly important for transition projects: separating projects that genuinely reduce emissions and align with long-term climate objectives from those that do not.

3 SFAC's proposed framework includes the Taxonomy Council and Custodian to maintain the scientific integrity of the taxonomy and its technical criteria. The Taxonomy Council would oversee governance, strategic direction, and performance of the taxonomy and approve all publication proposals. On the other hand, the Taxonomy Custodian, an independent organization, would handle technical tasks, education and awareness raising activities, and respond to feedback and technical inquiries. See the SFAC Taxonomy Roadmap for more details.

While the term *project* was not explicitly defined in the SFAC Taxonomy Roadmap, it is used in a way that is consistent with the more widely used term "capital project," defined as long-term and capital-intensive investments that construct, build upon, add to, or improve capital assets. Generally, projects have clear boundaries and legal ownership structures, whether it is a physical building or a piece of large equipment or infrastructure.

The other concept relevant to the taxonomy framework is *facility,* which represents the entire physical footprint of a site's operations. We propose adopting the existing definition under Canada's Greenhouse Gas Reporting Program, which defines a facility as: "all buildings, equipment, structures, on site transportation machinery, and stationary items that are located on a single site, on multiple sites or between multiple sites that are owned or operated by the same person or persons and that function as a single integrated site".

The boundaries of a taxonomy-labelled project may be narrower than the physical boundaries of a facility

The taxonomy aims to create standardized labels for financial instruments used to raise capital for green and transition projects. Specifically, the taxonomy will create standards for the issuance of use-of-proceeds loans and bonds that align with representative 1.5°C pathways.[4] The rationale for focusing solely on use-of-proceeds bonds and loans at this time is that the revenues can be clearly and transparently ring-fenced around specific projects. (See page 47 in the Roadmap Report for an explainer on how green and transition bonds would be issued in practice).

This focus on use-of-proceeds instruments, however, raises important questions about the boundaries of what is being financed through the taxonomy relative to the boundaries and operations of an entire facility. In some cases, particularly in the case of transition projects, the boundary of the project getting financed under the taxonomy may need to be narrower than the boundaries of a facility's operations. And while this distinction may sound superficial, it is a necessary one to protect the scientific credibility of the taxonomy. It also has direct implications for how eligible oil and gas projects are defined and categorized in the taxonomy framework.

A lot of this nuance regarding the boundaries between a project and a facility ultimately depends on whether the project in question has green or transition characteristics. For example, the transition category is, by definition, focused on the decarbonization of historically emissions-intensive facilities. This often means retrofitting existing facilities to get them on a trajectory that aligns with 1.5°C pathways. The green category, in comparison, is focused primarily on new projects that Canada needs more of to reach its climate

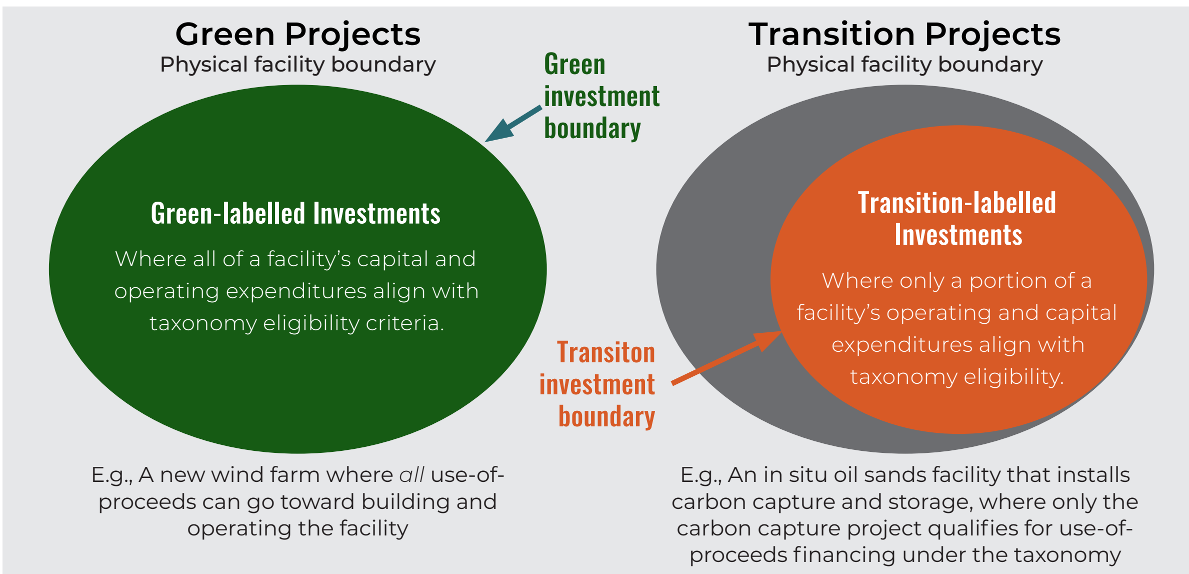
4 Eventually, the taxonomy could also be used to label entire companies and financial institutions as green or transition depending on the composition of their business activities and investment portfolios. This type of corporate label could facilitate general financing, whereby taxonomy-labelled funds could contribute toward a company's entire operation. The proposed taxonomy approach in Australia, for example, includes a framework for determining whether entire companies are eligible for the green or transition label.

objectives (e.g., new battery and storage manufacturing facilities, new wind and solar farms, new clean hydrogen facilities, etc.).

Figure 3 illustrates how the boundaries of *projects* and *facilities* may look different across the green and transition categories. The boundary of a green-labelled project, for example, can perfectly match the boundary of the facility. That is, all of the costs associated with building and operating the facility are eligible for the green label under the taxonomy. The entire facility demonstrates a low degree of transition risk and high transition opportunity and therefore warrants this more expansive definition.

Figure 3:

Defining the project boundary compared to the facility boundary



Green-labelled bonds or loans could, for example, help finance the construction of a brand-new wind or solar farm, or a green hydrogen facility. The issuance could also help finance capital upgrades to an existing green-labelled, facility-wide project. In other words, 100 per cent of green-labelled issuances can go toward directly increasing or enabling production of the good or service, whether it is low-carbon electricity, low-carbon hydrogen, or battery storage manufacturing.

For transition projects, however, the boundaries between the project and facility may look different. In most cases, transition-labelled projects are about reducing emissions at *existing* facilities. This will often mean retrofitting a portion of an existing facility by installing new technologies or processes. Examples include outfitting a cement facility with carbon capture technologies, installing electric arc furnaces at a steel facility (see Figure 3), or converting a traditional automotive manufacturing facility to make electric vehicles instead of internal combustion engine vehicles.[5] These investments could still be significant in terms

5 This paper refers to carbon capture utilization and storage as a broad category of technologies that can be deployed across multiple applications and sectors.

of total dollar value, but the use-of-proceeds investment would be restricted to financing only the decarbonization project within the broader carbon-intensive facility.

The rationale behind this distinction is to help preserve the integrity of the issuance for investors and capital markets. It effectively gives investors confidence that transition-labelled financing is exclusively going toward projects that are decarbonizing the industrial activity and, as a result, reducing a facility's overall transition risk.

There could, however, be circumstances where entire facilities within historically emissions-intensive sectors could become eligible for the green label (instead of a transition label). Aluminum production, for example, offers a range of pathways to significantly reduce lifecycle emissions, such as using clean electricity for the smelting process, increasing the use of recycled aluminum as a primary input, and deploying near-zero technologies to reduce refining and process emissions (e.g., carbon capture, low-carbon hydrogen).

The ability for facility-wide projects within historically emissions-intensive industries to become eligible for a green label raises a bigger question about the precise dividing line between the green and transition label. The SFAC Taxonomy Roadmap provides a high-level framework that differentiates transition and green projects (see next section), but more detailed criteria and thresholds will ultimately be required. These criteria and thresholds may also need to change over time as decarbonization pathways (and technological dead ends) become clearer. While these issues are largely beyond the scope of this paper, Box 2 explores some key considerations.

Box 2: Demarcating clear lines between green and transition projects

The Canadian Climate Investment Taxonomy will need to draw a clear line between green and transition projects. While both labels reflect important—and necessary—projects along Canada's path to net zero, the two categories embody different degrees of transition risk and opportunity. The green label is reserved for projects that have low or near-zero lifecycle emissions and align with the most recent net zero pathways.

In some cases, however, there may be facilities in historically emissions-intensive sectors that, through transformational projects, can align with the principles of the green label. This could include an aluminum producer, like the example above, or an EV manufacturer that is able to significantly reduce emissions across the entire supply chain, or a coal plant to be converted into battery storage. The ultimate goal is to reserve the green label for projects that deploy best-in-class technologies and make transformational emissions reductions.

Given that oil and gas facilities would be highly unlikely to meet the high standards established under the green label, questions about the interface between *green* and *transition* projects are beyond the scope of this paper. As Canada's taxonomy research moves into other emissions-intensive sectors, such as mining or heavy industry, the specific criteria and thresholds for determining when a transition project becomes eligible for the green label should become clearer. The sector-specific emissions intensity curves discussed in Section 2 could, for example, provide a way to determine whether or not specific investments made today are aligned with net zero by 2050.

It is noteworthy that the Canadian taxonomy is forging new ground in this space. Canada is one of few countries that includes both a transition and green category in its taxonomy, and could be the first country to provide detailed criteria and thresholds to demarcate the two categories based on transition risks and opportunities.

The boundaries for eligible oil and gas projects are even narrower

The distinction between the boundaries of a project and a facility becomes even more important for oil and gas projects. Given the necessary decline in global consumption of fossil fuels to achieve a 1.5°C target, new oil and gas facilities represent significantly higher transition risk and were therefore deemed ineligible for taxonomy financing in the SFAC Taxonomy Roadmap (discussed more in Section 2). Implementing this in practice means that transition-labelled oil and gas investments—by definition—must only include projects that reduce emissions at existing facilities. Again, these investments still may be large in terms of dollar value, but they will reflect a small share of the facility's total capital and operating expenditures.

The distinction is also necessary to prevent scenarios where taxonomy-labelled financial products (loans or bonds) are funding activities that are inherently inconsistent with 1.5°C pathways. For example, oil sands producers could spend an estimated $6.6 billion annually between 2023 and 2050 on sustaining capital.[6] This includes all capital expenditures required to sustain production levels and preserve the integrity of existing facilities (and excludes growth capital or capital used to expand a facility's operations).

At face value, these sustaining capital investments would not be considered consistent with the taxonomy's transition label. The new investments would need to be specifically devoted to decarbonization projects and would need to meet the taxonomy's criteria around facility lifespan and emissions reductions, along with company-level requirements and do-no-significant-harm criteria.

These nuances between the facility and project boundaries provide context for how oil and gas activities should ultimately be evaluated according to the taxonomy.

6 These estimates are based on the Canada Energy Regulator's Evolving Policy Scenario and cost data from 2015-2018. It was estimated using the average sustaining capital costs (per barrel) between 2015 and 2018, which we then multiplied by oil sands production estimates between 2023 and 2050 from the Canada Energy Regulator's Evolving Policy Scenario. Sustaining capital investments would likely be lower in a net zero or 1.5°C degree scenario.

As discussed in the next section, the physical boundaries of the facility still matter, as it is ultimately the facility as a whole that must align itself with representative 1.5°C pathways.[7]

Defining projects that involve multiple companies and cut across different sectors requires additional consideration within the taxonomy framework

There may be circumstances in the application of the taxonomy framework where the boundaries of a project extend beyond the boundaries of a single facility or sector. Large infrastructure projects, for example, may require capital investment across multiple companies. Big infrastructure projects may also provide services to multiple sectors.

The possibility of building a large carbon capture and storage hub illustrates these complexities. As discussed later in Section 2, some of the thresholds used in the taxonomy framework propose using sectoral benchmarks (aligned with 1.5°C pathways) as a way to assess the performance of a particular project. However, if a carbon capture hub can reduce emissions across multiple sectors, it is unclear which sector the project should be compared against (e.g., cement, oil and gas, chemicals?). And if a project involves multiple facilities, or even multiple companies, it is also unclear how the general requirements of the taxonomy would be applied.

The prospect of building pipeline networks could raise similar challenges. There may be opportunities, for example, to convert new or existing pipeline networks primarily used to transport oil and gas to transport captured carbon or low-carbon products such as hydrogen or renewable natural gas. Large-scale infrastructure projects that can credibly be "future proofed" against the risk of declining demand for fossil fuels could align with 1.5°C pathways and may, therefore, require a different set of criteria in the framework.

A partial solution would be to assess how the decarbonization technology getting financed will be deployed. For example, the installation of carbon capture on an existing oil sands facility may be treated as an existing conventional oil and gas project under the proposed framework in this paper, whereas the construction of a carbon capture hub that can provide sequestration services to multiple industrial sectors (e.g., cement, chemicals, etc.) may require different eligibility criteria that assess its impact beyond the oil and gas sector. In other words, the framework may require additional criteria around whether the investment is financing a decarbonization project within a single facility (where emissions reductions can be assessed against facilities' total emissions or production) or whether the project enables infrastructure or technology that extends beyond a single facility and impacts multiple operators (such as the case with a carbon capture hub).

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7 According to the IPCC, representative 1.5°C pathways are described as those, based on the current understanding of climate dynamics, that offer a likelihood ranging from one in two to two in three of either keeping warming below 1.5°C or returning to that level by approximately 2100, even after a temporary overshoot. It is important to note that there are various credible modeling options and scenarios to can be considered when assessing Representative 1.5°C pathways, each factoring in crucial elements of a transition to a net-zero economy such as climate change mitigation and adaptation strategies, technological innovation, consumer behavioral change, socioeconomic factors and policy evolution.

To ensure clear guidance in this area, the Taxonomy Council and Custodian could create a list of activities that would qualify as an enabling project. Doing so, however, will ultimately require further research and engagement with stakeholders, including industry. How these types of projects are assessed will have important implications for whether they are eligible for taxonomy-financed investment.

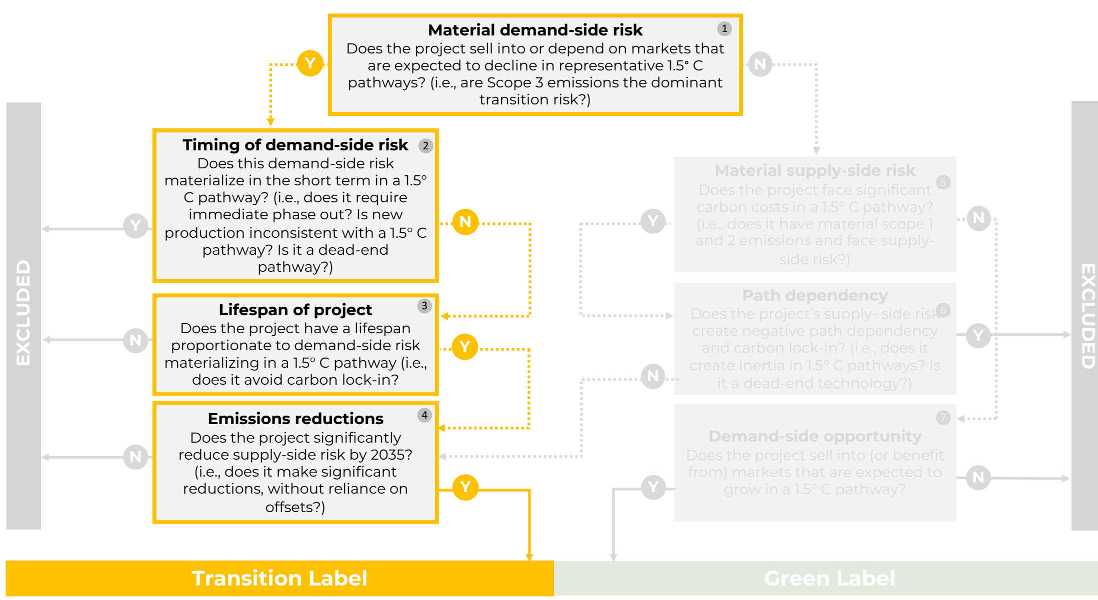
Section 2: Categorizing Oil and Gas Investments in the SFAC Taxonomy

This section is organized around three big research questions and is intended to kickstart discussions about how—and under what conditions—existing oil and gas projects (using the definition from Section 1) can be integrated into the SFAC taxonomy. These questions are sequenced in order of how they appear in the taxonomy framework in the SFAC Roadmap report (see Figure 4):

1. When are downstream Scope 3 emissions from a particular project considered the dominant transition risk? (Step 1 in the categorization framework)
2. What is the definition of new vs. existing oil and gas facilities? (Step 2)
3. How can the taxonomy determine whether project lifespans and emissions reductions align with 1.5°C pathways? (Steps 3 and 4)

Figure 4:

Categorization framework from the SFAC Taxonomy Roadmap Report



Source: SFAC Taxonomy Roadmap

The sections below tackle each question in turn. Each section starts with some general background information and analysis, followed by a proposed approach. This is followed by a brief discussion about the benefits and challenges with the proposed approach, and a consideration of the questions that still need additional research.

Note that all of the proposed criteria and thresholds discussed in this section would be used to determine whether a particular oil and gas project meets the eligibility criteria for a transition label. The issuer, in other words, would need to demonstrate that a particular project meets the set standards laid out by the taxonomy, which would then, according to the approach proposed in the SFAC roadmap, be verified by a second-party opinion provider (discussed more under Question #3).

Question #1: When are downstream Scope 3 emissions from a particular project considered the dominant transition risk?

BACKGROUND

This first step in the taxonomy (see the top of Figure 4) is designed to identify projects where the dominant transition risk is rooted in shrinking global demand in 1.5° C pathways. In financial terminology, this part of the framework is about identifying when downstream Scope 3 emissions are considered a material risk to investors and markets.[8]

The theory behind this criterion in the taxonomy framework comes from the Institute's 2021 report Sink or Swim: Transforming Canada's Economy for a Global Low-Carbon Future. This report identified the impacts of the ongoing global transition to a low-carbon economy under 1.5°C pathways on the Canadian economy by stress-testing Canadian publicly traded equities under different global low-carbon scenarios. The modelling highlighted two important findings:

1. The transition to a global low-carbon economy causes significant profitability losses for several major sectors in Canada, including upstream oil and gas, downstream and midstream oil and gas, coal mining, and heavy-duty vehicle manufacturing. By 2050, profitability losses range from 35 per cent for downstream and midstream oil and gas, to 78 per cent for upstream oil and gas in a 1.5°C immediate scenario.[9]

2. The biggest driver of these profitability losses is declining global demand for each sector's products—a concept known as demand destruction. In the 1.5°C immedi-

8 According to global accounting standards, financial materiality refers to information, events, or facts that could affect the judgment of an informed investor.

9 The *Sink or Swim* analysis used scenarios from the Network of Central Banks and Supervisors for Greening the Financial system. In the 1.5°C immediate scenario, action starts right away and steadily increases to maintain the global average temperature increase to 1.5 degrees Celsius. The results are assessed against the Network of Central Banks and Supervisors for Greening the Financial System's business-as-usual scenario, where there is no new climate policy (NGFS 2022).

> ate scenario, demand destruction accounted for 99 per cent of profitability losses for coal mining companies by 2050, and 67 per cent of losses for upstream oil and gas companies. The other large factor of profitability loss in these scenarios is rising carbon costs; however, this variable was far less dominant than declining global demand.[10]

The driving force behind the demand destruction in these sectors is the emissions associated with their end use (fossil fuel combustion), which are counted as oil and gas producers' downstream Scope 3 emissions. As policy, market, and technology forces accelerate the energy transition, demand for emissions-intensive forms of energy diminishes as consumers pivot to clean and low-carbon alternatives. These shifts are particularly pronounced in ambitious 1.5°C scenarios, where the consumption of coal, oil, and gas decrease between 45 per cent and 95 per cent by 2050, from 2019 levels.

The first step to operationalize this demand-side risk (or demand-destruction risk) in the taxonomy framework is to filter projects based on their downstream Scope 3 emissions. The goal is to separate projects where demand-side risk from downstream Scope 3 emissions is the dominant type of transition risk.

In practice, implementing this requirement means measuring greenhouse gas emissions at the facility level (see above for the distinction between project and facility). This aligns with how "facilities" are defined under Canada's Greenhouse Gas Reporting Program, which requires nearly 3,500 industrial facilities across Canada—covering all of the heavy-emitting sectors, including oil and gas—to report their greenhouse gas emissions annually.[11] The major difference, however, is that the taxonomy would assess a facility's full lifecycle emissions, unlike the Greenhouse Gas Reporting Program, which only covers Scope 1 emissions.

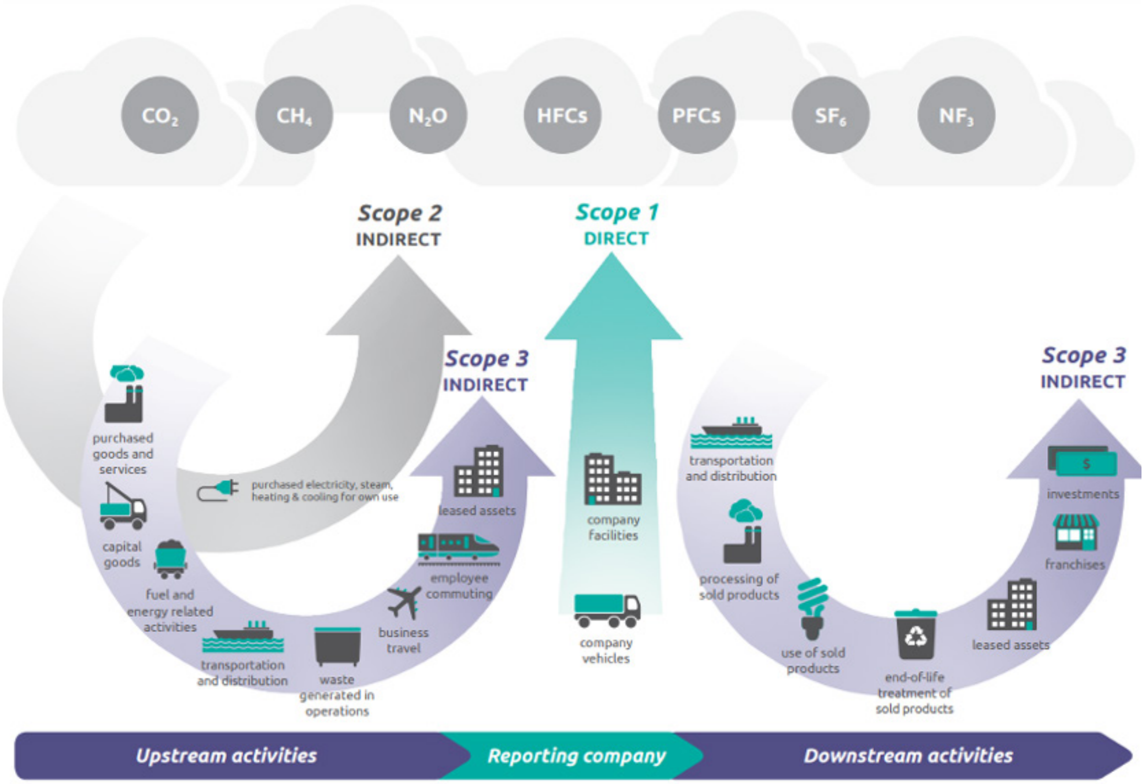
According to the Greenhouse Gas Protocol (the international gold standard for climate pollution accounting), Scope 3 emissions are grouped into 15 different categories (see Figure 5). The first eight categories refer to *upstream Scope 3 emissions* and the remaining seven refer to *downstream Scope 3 emissions*. Of these downstream emissions categories, Category 11—"use of sold products"—is the most material category for measuring demand-side risk, which covers the combustion emissions associated with products.

10 A portion of the profitability losses in these sectors are offset by opportunities for companies to abate emissions directly and avoid paying a carbon price, and passing through some of the additional costs to consumers. These impact channels were integrated into the *Sink or Swim* analysis and were relatively small relative to the impacts from demand destruction.

11 The focus on facility-level emissions creates a level playing field across companies that may or may not be vertically integrated. Any emissions that are generated from a facility's supply chain (that are not associated with its electricity consumption or counted as Scope 2 emissions) would be counted as Scope 3 emissions, regardless of whether those emissions occur within the same corporate entity.

Figure 5:

Categories of Scope 3 emissions accounting



Source: Greenhouse Gas Protocol (2013)

Global data from CDP, summarized in Figure 6, illustrates that Category 11 Scope 3 emissions represent a significantly higher percentage—more than 50 per cent—of total lifecycle emissions for sectors facing declining global demand. For the coal sector, Category 11 emissions represent 64 per cent of total emissions, whereas they represent 81 per cent of total emissions for the oil and gas sector.[12] These are the emissions associated with the combustion of fossil fuels, which represent the bulk of lifecycle emissions for oil and gas projects.

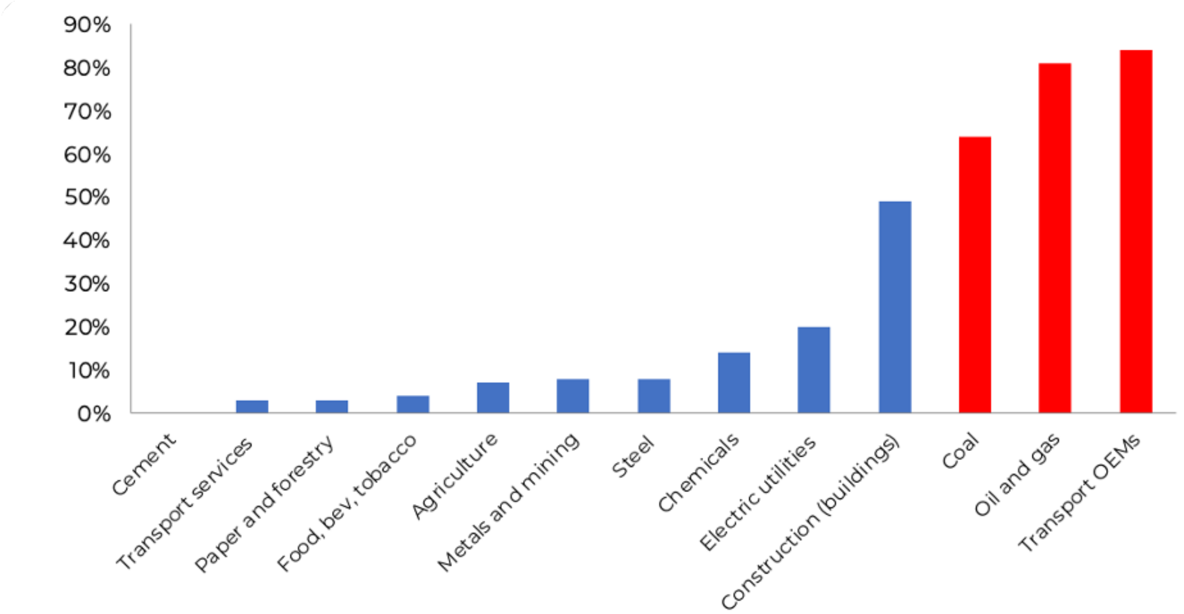
Starting with downstream Scope 3 emissions in the taxonomy reflects the general principle that not all types of Scope 3 emissions carry the same type or degree of transition risk.

It is exactly because fossil fuel producers have limited agency over how their products are ultimately used or combusted that their downstream scope 3 emissions represent a higher degree of transition risk than other types of facilities. More specifically, downstream Scope 3 emissions increase the risk of assets becoming stranded as global demand for oil and gas decreases and as their customers seek lower carbon alternatives. Downstream users are also highly heterogenous and disaggregated, which exacerbates this lack of agency.

12 The global coal sector includes both thermal coal and metallurgical coal mining, which may explain why the Category 11 emissions for this sector are less than oil and gas.

Figure 6:

Scope 3 Category 11 emissions as a share of total sector greenhouse gases



The flipside of stranded asset risk is the increased risk of "locking in" downstream Scope 3 emissions associated with oil and gas consumption. As discussed in Box 3 later in this paper, investors in oil and gas projects seek to maximize returns on their investments, such that once a project is built, investors and operators have an incentive to see out the full lifespan of the asset, providing prices remain high enough. This effectively "locks in" the combustion (or downstream Scope 3) emissions associated with oil and gas projects, making it harder and more expensive to achieve global climate goals (discussed in Question 2).[13]

For both of these reasons (the increased risk of both stranded assets and carbon lock-in), the taxonomy framework designates downstream Scope 3 emissions as reflecting a higher—and different—degree of transition risk than other forms of emissions.

By contrast, oil and gas producers tend to have more control over their *upstream* Scope 3 emissions. Upstream suppliers represent a much narrower set of economic actors. In some cases, the issuer may have the ability to procure their inputs from lower-carbon suppliers. In others, they may have sufficient buying power to encourage their upstream suppliers to reduce their emissions (thereby reducing the producer's upstream Scope 3 emissions).

Upstream Scope 3 emissions are therefore different than downstream emissions and, as a result, are dealt with separately in the taxonomy framework. These upstream Scope 3 emissions are covered in Step 4 of the framework when measuring greenhouse gas emissions reductions at the facility level.

13 Formalizing the risk of carbon lock-in within the taxonomy framework also aligns with the concept of double materiality, which recognizes the global impact that businesses have on global greenhouse gas concentrations and the resulting physical risks from an overheating climate.

Vehicle manufacturers and construction developers represent two notable exceptions to the concept of demand-side risk. Demand for vehicles and buildings is not what is expected to decline in the transition—rather it is the energy they consume. The ability to deploy clean energy substitutes in these sectors (for example, electric vehicles and heat pumps) enables them to significantly reduce the risks associated with carbon lock-in and stranded assets. In fact, it is exactly this substitution process by end users that drives the transition risks for upstream producers of fossil fuels. We discuss these nuances below.

Applying this first step in the taxonomy framework requires setting a threshold for when downstream Scope 3 emissions at the facility level are considered the dominant transition risk. This ultimately determines whether a project moves to the leftward track in the taxonomy framework (see Figure 4). Note: projects that move to the left after Step 1 in the framework are no longer eligible for a 'green' label; the highest possible categorization they can achieve is the 'transition' label.

PROPOSED APPROACH

In reviewing the relevant best practices in this area, we are not aware of any examples internationally or domestically that set materiality thresholds specifically on downstream Scope 3 emissions. The only threshold that comes close is the requirement under the Science-based Target Initiative, which recommends that companies report their relevant Scope 3 emissions if they exceed 40 per cent of their total emissions. This same threshold was also floated during the consultation process for the US Securities Exchange Commission's forthcoming rule on climate-related disclosures.

While the 40 per cent threshold is a helpful reference point, it may not suit the purposes of the Canadian taxonomy framework. Notably, the threshold is used to indicate when emissions at the company level should be publicly reported. The threshold also includes all (relevant) categories of Scope 3 emissions, including both upstream and downstream emissions. The threshold for the taxonomy framework, by comparison, focuses specifically on downstream scope 3 emissions and identifies when these downstream emissions at the facility level represent a dominant transition risk for a project.

Overall, we propose using a slightly higher threshold of 50 per cent for this first step in the taxonomy framework, based on several reasons.

First, it provides a clear way to separate fossil fuel projects from others. As illustrated by the data from CDP in Figure 6, all sectors related to fossil fuels—and the facilities within these sectors—have more than 50 per cent of their total emissions as Scope 3 Category 11 (or combustion) emissions. The 50 per cent threshold ensures that coal, oil and gas, and automotive manufacturing facilities need to make significant cuts in their Scope 3 Category 11 emissions to reduce their demand-side risk.

Second, the 50 per cent threshold is not so low that it would inadvertently screen in projects that face much smaller demand-side risk. The building sector comes close to the threshold, primarily due to the emissions associated with heating and powering buildings. However, transition risks in this sector may be more effectively addressed by splitting high-emissions buildings from low-emissions buildings (discussed more below).

Taking this approach would allow the Taxonomy Custodian to create pre-certified categories of activities, such that individual issuers would not necessarily have to calculate the downstream Scope 3 emissions associated with their facilities specifically. Any type of oil and gas facility, for example, would automatically be assumed to exceed this threshold, whereas facilities in other sectors, such as cement or steel manufacturing, or a wind or solar farm, would automatically fall below the benchmark.

There could be situations, however, where an issuer believes that the pre-certified categories do not apply to the specific characteristics of its facility. An oil and gas project proponent that believes its facility-level downstream Scope 3 emissions fall below the 50 per cent threshold would be required to disclose the appropriate data in the issuance to back up the claim. For example, if an oil or gas company's proposed project is to build a blue hydrogen facility (hydrogen produced using natural gas) and have it financed under the taxonomy, it would need to disclose the rationale and data to show that the facility's downstream Scope 3 emissions fall below the threshold. Similarly, a project where oil and gas is primarily or entirely used to make non-combustible products (e.g., asphalt, petrochemicals, carbon fibre, etc.) would need to disclose data showing that its facility-level emissions fall below the 50 per cent threshold. In both of these cases, projects would move on the rightward track in the taxonomy framework (refer back to Figure 4) and would follow a different set of criteria.

These pre-certified categories may also require added specification for different types of projects *within* sectors and *across* sectors.

Added specification may be needed *within* sectors in the case of transportation vehicle manufacturers and buildings. The taxonomy framework could, for example, establish clear guidance that if the issuer is building a project that ultimately relies on the burning of fossil fuels as the dominant use of the product (e.g., internal combustion engine vehicles or fossil-based space heating), then it would automatically be treated as having material demand-side risk and move leftward in the framework. If, on the other hand, the issuance is to build zero-emissions vehicles or low-carbon buildings, then it would automatically be considered to have low demand-side risk.

Shared projects or infrastructure that provide goods or services *across* sectors may also require added specifications (discussed in Section 1). A new carbon capture hub, for example, could provide sequestration and transport services to oil and gas, cement, chemicals, or other sectors. In these cases, an exception may be required for 'enabling transition infrastructure' that can reduce emissions from high-polluting sectors. This type of project could still have significant positive implications for emissions across sectors, and could also have implications for path dependency depending on the lifespan of the project. More research and analysis is ultimately needed to study these questions in more detail.

STRENGTHS OF THE PROPOSED APPROACH

It is simple for issuers to use and understand. The Taxonomy Custodian could create pre-certified categories to fast-track compliance with this step in the framework, relieving individual issuers or companies from having to collect and disclose the necessary data.

The pre-certified categories put the onus on transition issuers to disclose if they believe their project falls below the 50 per cent threshold. The taxonomy could establish the required data disclosures for this situation to ensure the information is standardized, accurate, and verifiable.

Using global sectoral data to establish thresholds allows the approach to become replicated and interoperable with other taxonomies. CDP, for example, is an internationally recognized organization with a well-established database of company-level and sectoral-level emissions data. Data from other credible international providers could also be considered.

The proposed approach supports and builds on emerging best practices in climate disclosure standards for measuring and reporting downstream Scope 3 emissions. Disclosing downstream Scope 3 emissions is quickly becoming an international best practice, most recently adopted by Canada's Office of the Superintendent of Financial Institutions and the International Sustainability Standards Board's 2023 guidance on climate-related disclosures.

However, it should be noted that not all oil and gas companies currently disclose Category 11 downstream Scope 3 emissions. Of the 16 oil and gas companies that disclose data with CDP, half deem Category 11 Scope 3 emissions relevant to their transition risk but do not yet disclose this data. Over time, regulators could make these disclosures mandatory and/or market expectations could mainstream them. In either case, the taxonomy can help support the push for greater disclosure while leveraging improvements to data quality over time.

CHALLENGES WITH THE PROPOSED APPROACH

Because the Canadian taxonomy is breaking new ground in defining when downstream Scope 3 emissions represent the dominant type of transition risk for a project, the 50 per cent threshold is not based on any other international standards. However, it is designed to set a high bar for sectors facing significant demand-side risk while simultaneously avoiding inadvertently capturing other sectors that do not face this level of demand-side risk. More research, analysis, and stakeholder engagement should ultimately be conducted to better understand how the threshold would be applied in practice.

The Taxonomy Council and Custodian, once established, would ultimately need to decide whether 50 per cent is the right threshold. Over time, the threshold could be reduced or refined to become more stringent. As research and data on sectoral emissions improves, it may become clear that the 50 per cent threshold is no longer adequate for screening projects with high demand-side risk.

Projects designed to reduce Scope 1 emissions (e.g., carbon capture) could actually increase the share of Category 11 Scope 3 emissions relative to total emissions. To avoid this outcome, a project would need to also sell a greater portion of non-combustibles to reduce their Category 11 emissions in parallel.

This possible outcome highlights two important features behind setting the 50 per cent emissions threshold. First, the primary purpose is to identify projects where a majority of emissions at the facility level are generated from the combustion of the product. Whether a facility has 70 per cent of its total emissions from Category 11 Scope 3 emissions or 80 per cent, it is largely the same conclusion: the facility on which the project takes place has a higher level of transition risk than that of other types of projects, and this risk needs to be reflected in how it is assessed in the taxonomy framework. This same conclusion applies to oil and gas facilities that significantly reduce their Scope 1 and 2 emissions but see the majority of their fuel products combusted.

Second, it reaffirms the need to establish a stringent (low) threshold. It helps avoid a potential situation where a facility appears to have a lower share of its emissions generated from Category 11 Scope 3 emissions because its operations are more emissions intensive (increasing the denominator to reduce the total share). It will be challenging for most oil and gas facilities (aside from a few exceptions) to meet this 50 per cent threshold, which reduces the risk that projects get miscategorized in the framework.

Solely relying on a relative threshold could mask important changes in absolute or cumulative emissions. This reflects a broader concern with the specific requirements in the taxonomy framework, in that they primarily rely on relative thresholds to measure emissions and emissions reductions. Yet integrating absolute measures into the specific requirements poses its own challenges. On one hand, absolute metrics can penalize projects taking place within larger facilities simply due to their size, which indirectly discourages company growth and economies of scale.

On the other hand, operationalizing absolute thresholds within the taxonomy to guard against the cumulative effects from individual facilities is extremely complex—particularly for the oil and gas sector. It would require setting an absolute limit of emissions for the sector in Canada, and linking these limits to a corresponding global carbon budget. Each facility, in other words, would need to be assessed against the global carbon budget for the oil and gas sector—and other existing facilities within the cap—to ensure that each additional facility fits within a cap. Such requirements would be unwieldy to design and implement in the framework.

The general requirements in the taxonomy are designed to directly address these concerns. Requiring issuers to include absolute emissions reduction targets across all three emissions scopes, for example, can provide assurance that the emissions from any specific facility fit within an issuer's overarching carbon budget on the path to net zero emissions. The taxonomy is also designed to complement policy tools that can more effectively address concerns about reducing absolute emissions, such as carbon pricing and the forthcoming cap on oil and gas emissions.

Question #2: How are new oil and gas facilities distinguished from existing facilities? (Step 2)

BACKGROUND

The second step in the categorization framework is designed to filter out projects and activities that are inconsistent with the most up-to-date emissions reduction pathways to achieve the 1.5°C global target. Ultimately, the goal is to ensure that taxonomy-labelled investments avoid locking in facilities (and their emissions) that make it harder or more expensive to reduce emissions in the future.

As noted in the Taxonomy Roadmap report, this step in the framework proposes to exclude all coal mining and internal combustion engine manufacturing. It also proposes excluding any type of projects that relate to *new* oil and gas facilities.

The proposal to exclude new oil and gas facilities is grounded in international climate science under representative 1.5°C pathways. Rigorous modelling and scenario analysis across multiple international institutions conclude that global consumption of oil and gas must decline sharply between now and mid-century to stay consistent with the 1.5°C target. Modelling results summarized by the IPCC, for example, show that limiting global warming to 1.5°C (with limited or no overshoot) requires the consumption of coal, oil, and gas to decrease between 45 per cent and 95 per cent by 2050 (from 2019 levels). In a 2023 report, the United Nations-convened Net-Zero Asset Owner Alliance also underlined that projected emissions from existing fossil fuels facilities alone already exceed the remaining carbon budget associated with science-based 1.5°C-aligned pathways. The Alliance has consequently committed to not provide new finance to any oil and gas facilities whose activities would not align with the imperatives of achieving these pathways.

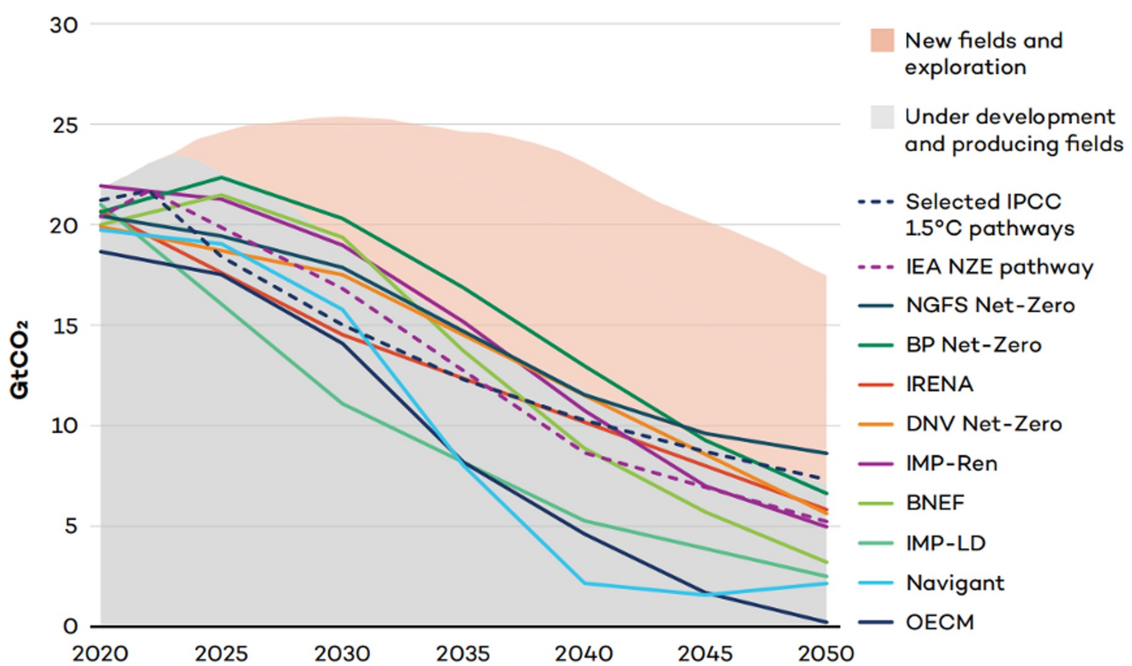
By extension, this means that production of fossil fuels must decline sharply in the coming decades to align with 1.5°C pathways.

While headlines from the International Energy Agency's 2023 report—which concluded that new oil and gas fields are incompatible with 1.5°C pathways—have garnered the most attention, the International Energy Agency's findings are in fact broadly consistent across other credible emissions scenarios. Analysis by the IPCC and other integrated climate models show similar reductions in oil and gas consumption, as illustrated in Figure 7 below.[14] These scenarios are also broadly consistent with the 1.5°C pathways used by the Network of Central Banks and Supervisors for Greening the Financial System, which the Canadian Climate Institute used as the foundation of its 2021 *Sink or Swim* report.

In practical terms, these pathways require global consumption of oil and gas to fall by 3 to 4 per cent annually—an amount that is approximately equal to the expected decline in the rate of production from existing oil and gas fields globally.

Figure 7:

Comparing the natural decline rate of existing oil and gas fields with multiple 1.5°C scenarios



Source: IISD et al. 2022

Despite this emerging consensus, however, distinguishing new oil and gas facilities from existing ones is not as simple as it might seem. Notably, the decline of oil and gas production in the coming decades does not require phasing out new investment in the oil and gas sector entirely. The International Energy Agency analysis, for example, includes incremental investments to maintain existing production in their Net Zero scenario (e.g., sustaining capital). These investments are required to maintain the decline rates depicted in Figure 7 (estimated to be 3–4 per cent) and to prevent even steeper rates of produc-

14 In fact, because the International Energy Agency's net zero scenario relies heavily on carbon capture and storage technologies, it could significantly underestimate the reductions necessary from the oil and gas sector to stay on a 1.5°C degree trajectory.

tion decline (estimated to be 8 per cent). In terms of actual investment, this means that only USD 400 billion in new investment is needed in 2030, which is approximately half of what it was in 2023.

At the same time, international attempts to distinguish new facilities from existing facilities either do not provide sufficient resolution for the purposes of the Canadian taxonomy, or do not fit the Canadian context. Various international initiatives (including the International Energy Agency and the Net-Zero Asset Owner Alliance) focus on phasing out investments for developing *new oil and gas fields*. Yet focusing solely on *new fields* would probably not, by itself, align with the 1.5°C target within the Canadian context. Most oil and gas fields in Alberta, for example, have had some type of activity on them over the past 100 years, which means that major expansions and greenfield facilities could meet the criteria for "existing" under this definition.

These nuances raise important questions for how the terms *new* and *existing* should be defined and applied for the purposes of the taxonomy, and within the Canadian context. Specifically, we considered the following questions:

- Should *existing facilities* include those that already have regulatory approval but have not been allocated significant capital? How should "significant" capital outlays be defined?
- Is the definition only applicable to upstream oil and gas production? Or should the definition also include midstream facilities? For example, should these definitions apply to Phase 2 of the LNG Canada facility? What if new midstream infrastructure, such as pipelines, increases demand for oil and gas production further upstream?
- To what extent should these definitions be based on the physical boundaries of a particular oil and gas field? To what extent should the definitions include details about the proven or probable reserves associated with a facility?
- How will these definitions treat the expansion of facilities that are already producing, particularly in the case of oil sands where significant expansions are currently planned?
- Do different types of oil and gas facilities require different definitions (e.g., conventional oil and gas vs. oil sands)?

PROPOSED APPROACH

Table 1 outlines the proposed criteria for determining what is an *existing* oil and gas facility. Due to differences within the sector (described in detail below), we propose slightly different criteria for oil sands facilities compared to conventional oil and gas facilities. A facility in each category must satisfy all of the criteria to be considered *existing*.

Table 1:

Defining existing oil and gas facilities

Existing oil sands facilities	Existing conventional oil and gas facilities
▸ A field where extraction and production are already taking place; AND, ▸ Where capital funds have already been committed and implementation of the development project or mining operation is underway (where a final investment decision was made by a specified date); AND, ▸ Where any facility expansions (if relevant) do not require new major infrastructure (e.g., gathering lines, processing facilities, upgraders, etc.)	▸ A field where extraction and production are already taking place; AND, ▸ Where any new pads and wells do not require new major infrastructure (e.g., gathering lines, processing facilities, upgraders, etc.)

The criteria in Table 1 build on and leverage pre-existing definitions and standards used internationally. For example, the U.N.'s Framework Classification for Fossil, Energy and Mineral Reserves and Resources includes a scoring system for oil and gas facilities based on their economic and social viability, field project status and feasibility, and geological knowledge. Of these U.N. classifications, we leverage their criteria (and sub-criteria) for field project status as the main way to define existing facilities, where:

- F1.1 A field where extraction is currently taking place; and,
- F1.2 Capital funds have been committed and implementation of the development project or mining operation is underway.

We complement these criteria by integrating the approach taken by the International Energy Agency, whose definition of existing oil and gas includes any facility or operation that has announced a final investment decision by 2021. The taxonomy's definition would similarly need to create its own cut-off date for its application; and while it makes sense for Canada to use the same date used in other international analyses, it would ultimately need to be selected by the Taxonomy Council and Custodian. We also propose specific criteria for facility expansions, to provide additional guardrails against significantly increased production from fields where extraction is already taking place.

In practice, the definition of existing facilities will depend on whether it is a conventional oil and gas facility or an oil sands facility. There is also a question of whether these criteria should apply to midstream oil and gas facilities. Each of these facility types is discussed in turn.

OIL SANDS FACILITIES

In many respects, existing oil sands facilities are easier to define compared to existing conventional oil and gas facilities (including shale). Oil sands facilities can take upward of a decade to plan and build, and have clearly defined boundaries. Applications to build a new oil sands facility include maximum limits on total production, the total land area of the different extraction sites, along with the required gathering, processing, and transportation infrastructure required for the facility. Due to their high upfront capital costs, oil sands facilities also have clearly defined final investment decisions.

Determining precise criteria for expanding existing oil sands facilities is more challenging but can be informed by disclosures in the existing regulatory process. Take, for example, Imperial Oil's 2016 Cold Lake Expansion project. In the regulatory approval process, Imperial laid out the additional supporting infrastructure required to make the facility viable. It includes central processing infrastructure (oil treating units, steam generation units) and interconnections with existing operations (natural gas pipeline, electrical connection).

While the Cold Lake Expansion project is used for illustrative purposes only, the proposed criteria for the taxonomy in Table 1 would likely designate this as a 'new' facility if it were making the application today, in 2024. The Taxonomy Custodian and Council will ultimately need to provide additional precision around the criteria for supporting infrastructure. It will also need to select a cut-off date for expansions, after which facilities and any associated decarbonization projects would be designated as new.

CONVENTIONAL OIL AND GAS FACILITIES

The boundaries for conventional oil and gas facilities are less clearly defined. Unlike oil sands, conventional oil and gas wells are regulated and approved at the individual well. The boundaries of a single facility are therefore more amorphous. Drilling new wells typically does not require final investment decisions, as with oil sands facilities, and are instead treated as ongoing capital expenditures of companies.

Thus, for conventional oil and gas, defining a facility around its existing infrastructure provides the stronger (and clearer) way to identify an *existing* facility. If an issuer can drill additional new wells and pads within the pre-existing supporting infrastructure, then it would be considered existing production. If, by contrast, building new pads or drilling new wells requires constructing new supporting infrastructure (for example, gathering lines, or gas processing plants), it would be labelled as *new* and become ineligible for taxonomy financing. Again, the Taxonomy Custodian and Council would need to provide additional detail on exactly what types of supporting infrastructure would trigger the *new* definition.

MIDSTREAM OIL AND GAS FACILITIES

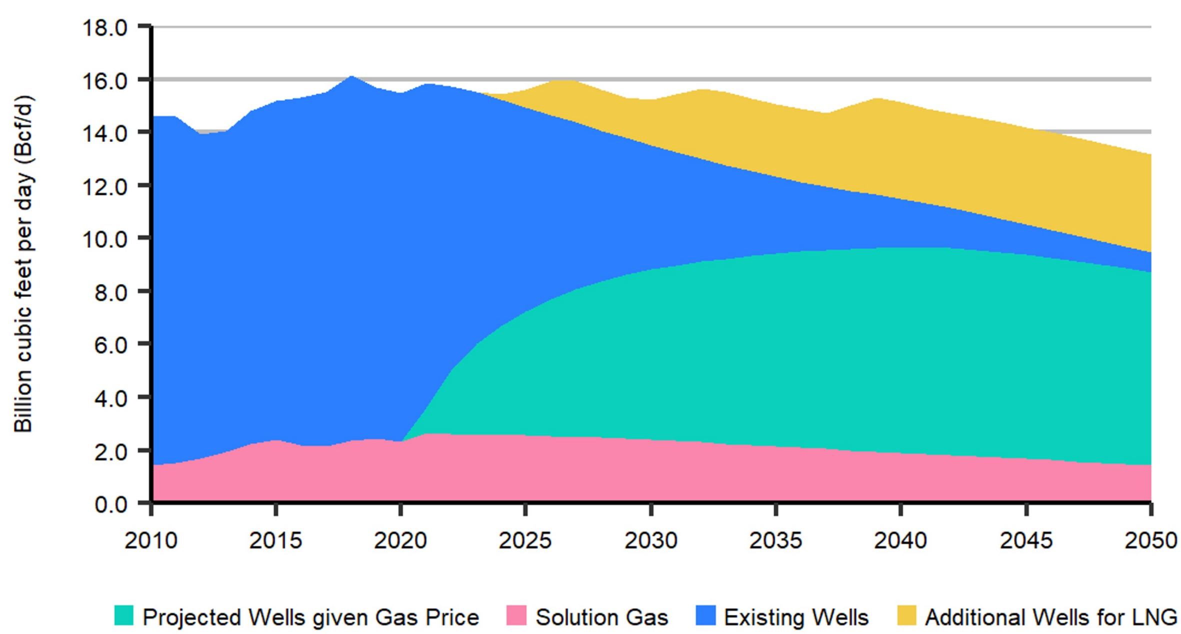
While the SFAC Taxonomy Roadmap does not specify whether midstream oil and gas facilities should be subject to the same *new* vs. *existing* criteria, there is a strong rationale for including them in the proposed approach.

Preliminary research suggests that new midstream facilities could have significant implications on upstream and downstream emissions. In particular, building new midstream facilities could induce demand for new or incremental upstream production. For example, Phase 2 of the LNG Canada project is expected to induce demand for drilling additional wells. It is unlikely that all of these additional wells would meet the *existing facilities* requirements.

Figure 8 below shows Canadian natural gas production in the Canada Energy Regulator's Evolving Policies Scenario. As production from existing wells (blue) declines, new wells are drilled to maintain supply (green). The orange wedge shows the additional production brought online to meet demand from new liquified natural gas facilities.

Figure 8:

Western Canadian marketable natural gas production by well vintage (Evolving Policies Scenario)



Source: Canada Energy Regulator

More research and stakeholder engagement are required before making a final decision on whether midstream facilities should be subject to the same *new* facility or *existing* facility criteria. The final decision on this point would ultimately come from the Taxonomy Council and Custodian.

BENEFITS OF THE PROPOSED APPROACH:

It establishes a relatively straightforward and practical way to define *existing* facilities. Using final investment decisions, facility approvals, and infrastructure requirements to distinguish new from existing facilities helps avoid more technical criteria or thresholds around the reserves associated with given facilities, or the geology or geographic boundaries of a facility. While incorporating these considerations into the definitions is possible, it may add undue complexity to the application of the taxonomy.[15]

By utilizing existing definitions and principles from the U.N. and the International Energy Agency, this approach helps build international credibility. The U.N. definitions are used by a range of international regulatory bodies, such as the Committee for Mineral Reserves International Reporting Standards Template, the Society of Petroleum Engineers, World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, and the Petroleum Resource Management System. The proposed approach also aligns with International Energy Agency practices.

CHALLENGES WITH THE PROPOSED APPROACH:

There is a third category in the U.N. criteria for field status that would not be reflected in this approach. This third criteria (F1.3) includes facilities where "sufficiently detailed studies have been completed to demonstrate the feasibility of extraction by implementing a defined development project or mining operation."

However, including this criterion could significantly broaden the definition of existing facilities beyond a point that is inconsistent with the taxonomy's core climate objective. As a result, it could undermine the credibility of the taxonomy and open it up to greenwashing risk.[16] We propose excluding this third criterion from the definition for existing facilities.

The proposed definitions would exclude new oil and gas facilities that utilize best-in-class technologies to dramatically reduce Scope 1 and 2 emissions. One of the most promising technologies for in situ oil production, for example, uses solvents instead of steam, which can reduce the carbon intensity of production by upwards of 80 per cent. These technologies, however, can only be deployed (to their full potential) on new in situ facilities.

While scaling up best-in-class technologies for new facilities is desirable from the perspective of reducing emissions (producing less emissions than a scenario where these technologies are not used on new production), the taxonomy must draw a clear line

15 Reserves, for example, are (in part) based on the economic viability of extraction at different global oil prices, which can change significantly over time. The U.N. Framework also notes that different jurisdictions use different definitions of reserves, which is why it explicitly avoids using the term in setting its own definitions. (The International Energy Agency similarly avoids the term.)

16 We refer back to the Taxonomy Roadmap that states: "The taxonomy is designed to set the highest possible standard and provide a path that aligns with the global transition, and global capital markets that will facilitate the transition. Where there is ambiguity, the taxonomy should err on the side of maintaining this international credibility."

between *new* and *existing* facilities. This is primarily due to the high risk of carbon lock-in associated with new facilities and their cumulative effects (see Box 3), which the taxonomy must guard against.

Opportunities under the taxonomy to decarbonize oil sands facilities and conventional oil and gas facilities may not always be equal. The proposed definition of *existing* could enable taxonomy-labelled projects to decarbonize both oil sands and conventional oil and gas (scopes 1 and 2). However, these opportunities will likely differ in both scope and scale, in part driven by the fundamental characteristics of each production method, such as upfront capital costs, marginal production costs, sources of greenhouse gas emissions, and facility lifespans.

Box 3: Carbon lock-in and stranded assets

The proposed approach for determining whether a given oil and gas facility should be considered new or existing relates directly to the risks associated with carbon lock-in and downstream Scope 3 emissions. New facilities—regardless of how much they can reduce their upstream production emissions—pose a high risk of locking in additional global emissions and are therefore deemed inconsistent with the taxonomy's goal to align with representative 1.5°C degree pathways.

Carbon lock-in can manifest in different ways. Investors behind new facilities are committed to maximizing the return on their investment, such that once a facility is built, investors and operators have an incentive to see out the full lifespan of the asset. This situation is particularly relevant in the oil sands where facilities can produce for decades and also have a cost structure that allows them to remain profitable at low oil prices once their capital costs are paid off. At the same time, new facilities incrementally increase the global supply of oil and gas and put downward pressure on prices. In turn, cheaper prices (all else equal) incrementally reduce the incentive for consumers to switch to cleaner alternatives.

Both of these effects serve to lock-in the associated emissions from a new facility. For example, if a new oil facility can produce 100,000 barrels of oil per day with a lifespan of 30 years, the downstream emissions associated with these reserves are at a high risk of becoming locked into production as investors seek a full return on the investment. Importantly, the lock-in associated with new facilities also relates to the social and political power of the industry, which can create additional inertia in the transition.

The flipside of carbon lock-in is stranded asset risk. If global demand for oil and gas drops faster than expected by investors and industry, it could result in significant write-downs or assets becoming stranded. This risk is particularly high for newer assets that have yet to pay off their upfront capital costs, which for Canadian oil sands production can be significant. In aggregate, these types of write-downs and stranding can have economic, environmental, and social implications that extend well beyond each individual company, and often pose a disproportionate risk to rural, remote, and Indigenous communities that depend economically on these assets.

It is important to note, however, that the proposed approach does not completely address the risk of carbon lock-in for existing facilities. Transition-labelled investments for an existing oil and gas facility face the same situation described above, where once a major investment is made to decarbonize an asset, investors and operators will want to ensure they maximize the return on the investment—"locking in" the associated Scope 3 emissions from the facility. Investments to decarbonize oil and gas production could also help extend the lifespan of facilities, either directly by upgrading equipment necessary for production, or indirectly by making the facility more carbon-competitive.

Yet, despite these challenges with managing lock-in from existing facilities, there is a clear need to decarbonize Canada's oil and gas sector to meet its climate targets. Even in 1.5° C scenarios, global demand for oil and gas will provide a market for Canadian producers in the short to medium term. In the longer term, the risk of carbon lock in and stranded assets will be lowest for producers that can stay competitive on both costs and carbon emissions.

FUTURE RESEARCH QUESTIONS

The proposed approach raises several important research questions, detailed below.

1. **How does the proposed definition for *existing* oil and gas facilities match up against estimated Canadian production in 1.5°C scenarios?**

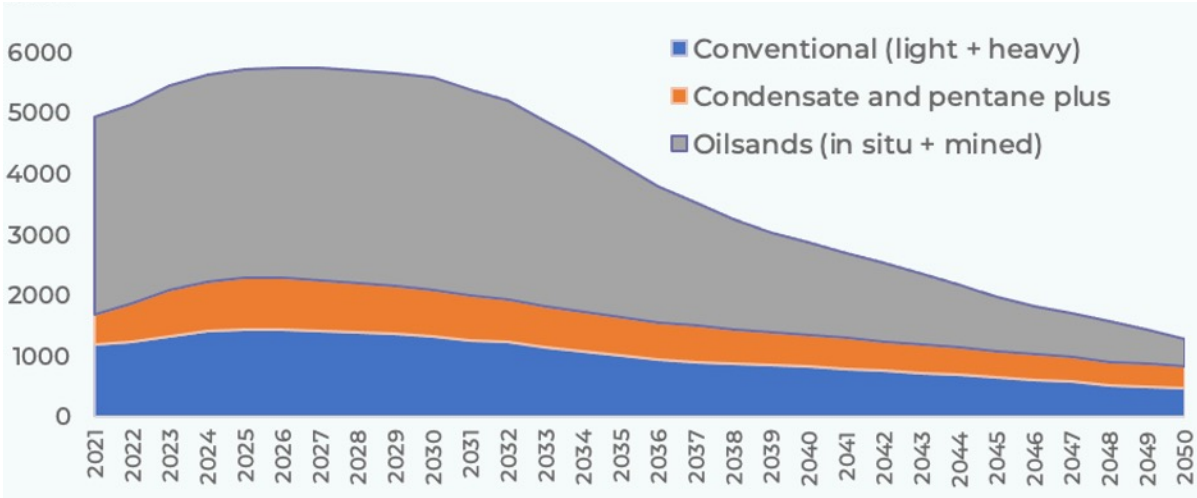
   In other words, how much incremental Canadian production is captured under the definition of existing facilities? Answering this question will help provide insights on the types of *existing* facilities and whether production from these facilities is sufficient to meet domestic and export demand in 1.5°C scenarios.

   The answer to this question, however, may look different for oil sands relative to conventional oil and gas production.

   According to a recent analysis by the Canada Energy Regulator, Canadian crude oil production from oil sands is expected to decline faster than conventional oil. Figure 9 shows crude oil production in the Canada Energy Regulator's Global Net Zero scenario (which is consistent with a global 1.5°C target). In this scenario oil sands production could fall by as much as 86 per cent between 2022 and 2050, suggesting that existing oil sands facilities would be more than sufficient to meet these production volumes. In fact, these results suggest that existing facilities may become unprofitable or stranded as global oil and gas prices decline through transition.

Figure 9:

Total Canadian crude oil production in the Canada Energy Regulator's Global Net Zero scenario



Source: Canada Energy Regulator 2023

The story for conventional oil and gas looks different. The Canada Energy Regulator's data suggest that demand for conventional oil and gas could decline more slowly in a 1.5°C scenario. This is primarily because conventional producers have much shorter payback periods, where individual wells produce most of their oil in the first few years after getting drilled. Producers are therefore nimbler in responding to price changes.

These results suggest that new wells may be necessary to offset the natural decline rate of existing conventional oil and gas wells, even in 1.5°C scenarios. The question remains, however, how many of these wells could operate within the existing supporting infrastructure. Wells that utilize existing infrastructure (as per the definitions laid out in Table 1) could, for example, be deemed 'existing'. This is a question marked for future analysis.

2. **How will the cap on oil and gas emissions affect the taxonomy's determination of new vs. existing facilities?**

There could be a situation where an oil and gas company—because of the binding emissions cap—wants to retire an older, emissions-intensive oil-producing facility to instead build a newer and more efficient oil-producing facility to make space under the emissions cap. Yet if the definition of 'new' and 'existing' is applied rigidly, the new facility would not be eligible for transition-labelled financing.

This situation may be rare, however, and would likely not result in a net reduction in emissions if the cap is binding. The newer, more energy efficient facility would likely increase production beyond what was possible at the retired facility to the point where its emissions hit the cap. Moreover, unless the new facility has a shorter lifespan than the retired facility (unlikely), the new facility would increase the risk of emissions lock-in, which is inconsistent with the principles of the taxonomy (see Box 3).

Question #3: How can the taxonomy determine whether facility lifespans and emissions reductions align with 1.5°C pathways? (Step 3)

BACKGROUND

The final two steps of the categorization framework propose criteria for whether facility lifespans and emissions reductions align with 1.5°C pathways. These final two criteria are only applicable to projects that have clearly demonstrated that they fall within the definition of an *existing* facility, as per the criteria proposed above.

The logic behind these criteria is to guard against carbon lock-in and stranded asset risks. Both risks have social and economic implications that extend far beyond the private company operating the facility or issuing the taxonomy-labelled financial product. It is for this reason that the taxonomy includes safeguards to minimize these risks—and to ensure consistency with 1.5°C pathways. These criteria would also create a standardized way of measuring these risks, which markets currently lack in Canada.

For facility lifespans, the goal is to ensure that the expected life of particular oil and gas facility roughly aligns with the timing of demand-side risk in 1.5°C pathways. In other words, the facility's lifespan must align with the horizon of declining international demand for oil or gas in transition.

For emissions reductions, the goal is twofold.

The first goal is to ensure that a project's facility-level Scope 1 and 2 emissions are consistent with 1.5°C pathways. In other words, the taxonomy-labelled project would need to drive down the Scope 1 and 2 emissions of the entire facility, such that it puts the facility on an emissions trajectory consistent with these pathways.

The second goal is to ensure that a project's facility-level upstream Scope 3 emissions are also aligned with representative 1.5°C scenarios. This requirement is particularly relevant for projects in midstream or downstream oil and gas facilities that may have significant upstream Scope 3 emissions.

An existing liquified natural gas facility looking to electrify its liquefaction process, for example, may still source its gas from producers that have high rates of fugitive methane emissions. These emissions would be counted as the facility's upstream Scope 3 emissions. In these cases, the issuer would need to demonstrate that its upstream emissions from natural gas extraction, processing, and transportation are consistent with 1.5°C pathways.

A petrochemical facility looking to decarbonize and finance a project through the taxonomy would need to meet similar upstream criteria. The facility would need to demonstrate that its oil and gas inputs are sourced from upstream suppliers that can demonstrate best-in-class emissions reductions that align with 1.5°C pathways.

In aggregate, the goal of these requirements is to ensure that only projects that make significant reductions to facility-level emissions are eligible for taxonomy financing. And these projects would need to align with a broader—and credible—plan to comply with representative 1.5°C pathways at the facility level (including transition plans, capital expenditure plans, disclosure, etc.). The taxonomy would not, for example, provide a transition label for general operating expenditures or sustaining capital expenditures for oil and gas operations (refer back to Section 1). Oil and gas companies could still make investments to increase or maintain production without significant emissions reductions, but these would not be considered transition-labelled investments under the taxonomy.

Finally, it is important to note that this step in the taxonomy framework is not intended to address downstream Scope 3 emissions. These emissions are covered in the first step of the framework, which excludes new projects. Refer back to Box 3 for more details.

PROPOSED APPROACH

The original proposal to operationalize this part of the taxonomy framework was to have issuers conduct a detailed cash flow analysis of their project. The analysis would have included the emissions abatement costs, such that the overall facility's emissions intensity would be consistent with 1.5°C pathways. Cash flows would then be stress tested by using projected oil and gas prices in representative 1.5°C scenarios.

After circulating this proposal to the Working Group and the SFAC Taxonomy Expert Group, it was clear that while the cash flow approach was well grounded in theory, it was not practical or robust enough to determine whether projects are eligible or ineligible for the transition label under the taxonomy.[17]

We now propose a simpler approach to determining whether the lifespan and emissions of a facility are consistent with 1.5°C scenarios. It includes two steps, articulated below.

17 The SFAC's taxonomy work is aided by the Taxonomy Technical Expert Group and the Net Zero Capital Allocation Working Group. The Taxonomy Expert Group assists in defining green and transition investments and activities within Canada's capital markets, considering the needs of market participants. Simultaneously, the Working Group offers recommendations to tackle challenges in channeling private capital towards net-zero solutions.

Step 1: Demonstrate compliance with Scope 1 and 2 emissions reductions over the facility's lifespan

The first step is to evaluate whether a facility's lifespan and Scope 1 and 2 emissions align with 1.5°C pathways. While the categorization framework separates these criteria as two different steps (see steps 3 and 4 in Figure 4), we propose operationalizing them together.

Specifically, we propose using sectoral emissions-intensity curves in 1.5°C scenarios as the benchmark for taxonomy compliance. Issuers would need to ensure that the facility falls below their sector's curve to remain eligible for taxonomy financing.

The rationale behind this approach is that each facility would need to demonstrate that it not only meets an emissions reduction threshold today, but that its emissions intensity falls over time in accordance with what is necessary in 1.5°C scenarios. A facility that emits above this sectoral benchmark would represent a higher risk of locking in carbon emissions than one that outperforms the benchmark. Moreover, facilities with longer lifespans will need to demonstrate that they can comply with a benchmark that becomes increasingly stringent. Facilities with shorter lifespans face less exposure to the most stringent thresholds (which would approach zero by mid century) and therefore have an easier time complying with the threshold.

This approach could also facilitate the early retirement of high-emitting facilities. These are facilities that, if operated until the end of their useful life, would not (or could not) meet the emissions-intensity thresholds or qualify for taxonomy-labelled financing. While most of the discussion internationally around the phase-out of high-emitting facilities has focused on coal-fired electricity (an activity excluded in the SFAC framework and therefore not addressed in this paper), it could become increasingly relevant for the oil and gas sector in the coming decades (see Box 4).

Box 4: Integrating the managed phase-out of high-emitting facilities

Research by the IPCC suggests that some existing fossil fuel facilities or assets (globally) need to be phased out before the end of their useful life in 1.5°C pathways. The bulk of these early retirements are expected to come from the accelerated phase-out of coal-fired electricity. Over time, however, high-emitting assets in other sectors may also require early retirement, such as oil and gas, heavy industry (e.g., steel mills, cement), and transport (e.g., shipping, road vehicles).

How these facilities get phased out—whether abruptly or managed gradually—has big implications for companies, investors, workers, and communities. The goal is to proactively address (or avoid) the risk of assets becoming stranded, thus facilitating a smoother transition. A managed phase-out also provides an alternative to divestment, which tends to shift assets onto the balance sheets of financial players not bound by climate commitments.

Financial tools to facilitate a managed phase-out of high-emitting facilities are still in their infancy, but it is clear that taxonomies could play an important role. The taxonomy framework developed by the Association of South East Asian Nations (ASEAN), for example, includes bonds and loans that help finance early retirement of coal facilities as eligible for its Green or Amber label. Potential benefits include: lower costs for customers through switching to cheaper renewables; cheaper refinancing terms for investors due to lower transition risk; and a smoother transition for workers and communities.

While Canada has already made important gains in phasing out coal-fired electricity, the taxonomy's "transition" label could help finance the early retirement of its remaining facilities. Like the ASEAN taxonomy, this could be the first area of focus for the Canadian framework.

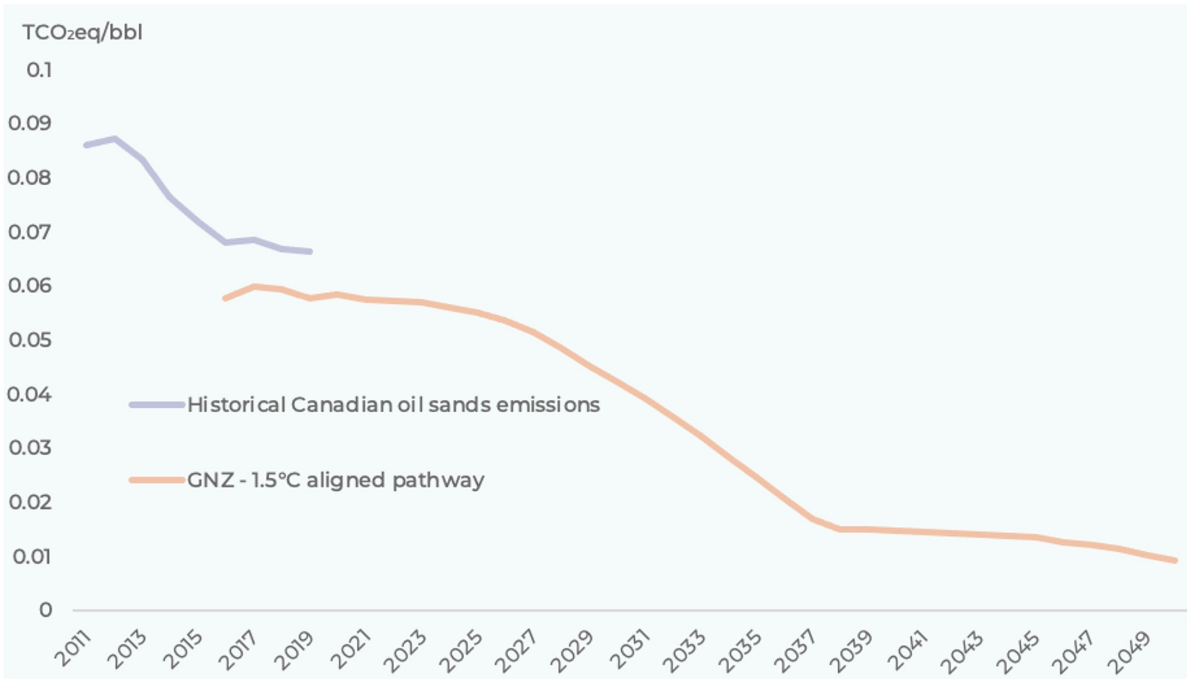
Whether the taxonomy could apply to other high-emitting facilities, however, is less clear. Retiring coal-fired electricity facilities is made easier by the stable and growing demand for electricity, cheaper renewables, and a market that is regulated domestically and insulated from fluctuations in global commodity prices. The transition for oil and gas, on the other hand, will be driven by declining global demand and continued price volatility. There may also be fewer opportunities to transition oil and gas facilities into cleaner alternatives that generate new revenue streams.

Still, issuing transition-labelled loans and bonds through the taxonomy could help facilitate the early retirement of these high-emitting facilities in Canada and is worth further exploration by the Taxonomy Council and Custodian. The framework proposed by the Glasgow Financial Alliance for Net Zero, for example, provides a helpful starting point and uses sectoral emissions-intensity curves similar to those discussed in this section. Their framework allows an emissions-intensive facility to keep operating in the short term with limited abatement, but with a commitment to retire early. Effectively, the retirement date is calibrated to align with the sector's 1.5°C pathways, such that the emissions saved from early retirement more than offsets those additional emissions in the short term.

Integrating early phase-out within the taxonomy would also align with the latest proposal by the European Union to extend its taxonomy categorization to "activities that must urgently transition, or exit". Sectoral emissions-intensity curves developed under a global net zero scenario by the Canada Energy Regulator provides a starting point for developing these dynamic thresholds. Figure 10 below shows the emissions intensity of the oil and gas sector consistent with a 1.5°C temperature target in the global net zero scenario. It also shows the historical emissions intensity of Canadian oil sands producers for context.

Figure 10:

Canadian oil sands emissions intensity vs. 1.5°C GNZ pathway



Source: Canada Energy Regulator (Global Net Zero Sectoral Benchmark) and Alberta Energy Regulator (Alberta Oil Sands Greenhouse Gas Emissions Intensity Analysis)

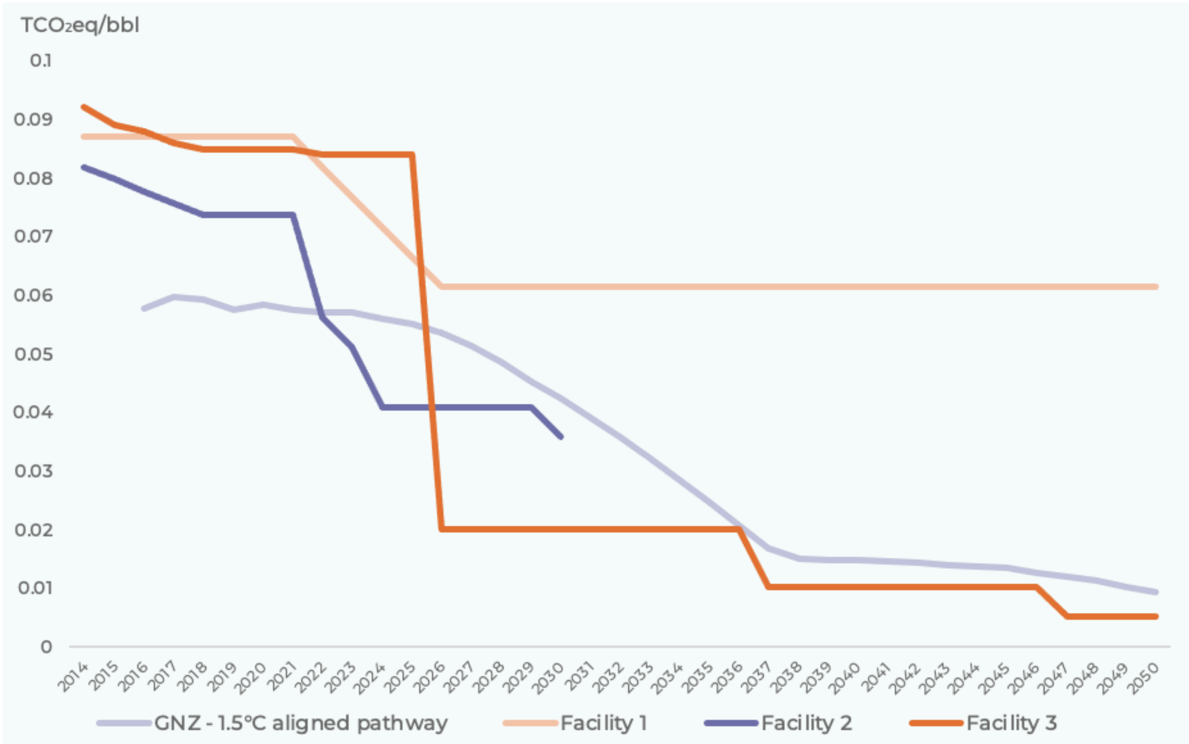
The goal with this approach is to develop emissions-intensity pathways for different parts of the oil and gas sector. Ideally, the taxonomy would have at least three pathways to start: natural gas, light oil, and heavy oil. This could involve, for example, using data from the International Energy Agency, Canada Energy Regulator, or the Canadian Climate Institute.[18]

Figure 11 below shows some theoretical examples of how this dynamic threshold could be used to evaluate individual facilities. It shows the same emissions-intensity pathway for the oil and gas sector in the Canada Energy Regulator's global net zero scenario, along with three hypothetical facilities with different lifespans and emissions intensities.

18 The Canadian Climate Institute has developed sectoral emissions curves in net zero scenarios that are disaggregated across oil and gas (natural gas, oilsands, conventional oil). The challenge, however, is that the Climate Institute's sectoral pathways reflect domestic emissions reduction targets and not global emissions reduction targets. This discrepancy between domestic and global pathways would need to be resolved in the future, as the goal would be to use global sectoral pathways for the Canadian taxonomy.

Figure 11:

Global oil and gas sectoral pathway and three hypothetical Canadian facilities



Source: Canada Energy Regulator (Global Net Zero Sectoral Benchmark)

Facility 1, for example, has a long lifespan (extending to 2050) and improves its emissions-intensity between 2022 and 2026. However, its emissions intensity is not low enough to comply with the benchmark. This type of facility would be ineligible for transition-labelled financing using this approach.

By comparison, Facility 2 is an older operation with a shorter lifespan (facility closure in 2030) with big emissions reductions in 2022. This facility falls below the established threshold over the lifetime of its operation and would therefore demonstrate compliance with this step of the framework.

Lastly, Facility 3 has the same lifespan as Facility 1 but it makes transformational upgrades to its emissions-intensity in 2026, which puts the facility below the sector benchmark. Additional improvements for the remaining years keep the facility below the benchmark. This facility would comply with this threshold out to 2050. In these circumstances, facilities would be required to include detailed strategies and capital plans in their issuance (see below for more details).

In developing the sectoral emissions-intensity curves, the Taxonomy Council and Custodian may need to set clear guidelines on how emissions credits (generated through existing regulations, such as Alberta's Technology Innovation and Emissions Reduction

Regulation) will be treated in calculating a facility's emissions performance, and whether the facility meets taxonomy thresholds.

At a high level, a facility that reduces its emissions through a transition-labelled investment should not be able to both count these emissions reductions toward its own net zero targets and simultaneously sell the credits generated from these emissions reductions on the credit market. For example, an oil facility that invests in carbon capture to comply with the taxonomy's threshold for Scope 1 emissions cannot then go and sell the credits generated from these emissions reductions on the TIER or CFS credit markets. This would effectively double-count the emissions reductions and would be inconsistent with the taxonomy's objective to reduce facility-level emissions. While this issue requires more research and analysis, voluntary retirement of credits could be one potential solution.

The Council and Custodian will also need to develop clear guidelines on the application of carbon capture technology and how it gets treated under the taxonomy. Carbon capture is viewed by industry as a critical decarbonization pathway, yet lingering uncertainty around the viability of the technology raises important questions. It is unclear, for example, whether carbon capture technologies are commercially viable at the scale required and at a cost that would enable widespread deployment.

In Canada, the majority of carbon capture projects use the captured carbon emissions for enhanced oil recovery, which can lead to net increases in both total oil production and greenhouse gas emissions (see Box 5). The Taxonomy Council and Custodian will need to carefully consider issues with monitoring and reporting the carbon emissions from carbon capture projects (whether for enhanced oil recovery or not). Under the U.S. 45Q tax credit for carbon capture, for example, there have been major discrepancies between actual and reported values of stored carbon emissions; in one instance, a company reported 60 million tons of sequestered emissions for tax purposes while reporting 3 million tons to the EPA as certified sequestered emissions. The relative permanence of the sequestration is another area that requires further study.

Box 5: Evaluating carbon capture projects for enhanced oil recovery

The SFAC Roadmap report did not provide specific guidance on how carbon capture projects should be assessed in the taxonomy framework. Among the different applications of carbon capture, it is particularly important that the Taxonomy Council and Custodian determine how to categorize projects where the captured emissions are used for enhanced oil recovery.

In general, enhanced oil recovery is a process that uses water flooding, gas cycling, gas flooding, polymer flooding or other methods to extract oil once primary methods of recovery are no longer producing efficiently. Using CO_2 as an enhanced oil recovery fluid is an option that has the potential benefit of storing CO_2 in the reservoir after fossil fuels have been produced. Of the seven operational carbon capture projects in Canada, five are used for enhanced oil recovery and represent about 70 per cent of the total carbon emissions captured from carbon capture in Canada.

There are also different types of carbon capture for enhanced oil recovery that could have different implications for taxonomy eligibility. The traditional application of carbon capture for enhanced oil recovery maximizes oil production by using the minimum amount of solvent possible (in this case, CO_2). In these traditional applications, permanent storage of CO_2 is treated as a co-benefit instead of a primary objective of the project. Newer forms of carbon capture for enhanced oil recovery, however, may prioritize sequestration as the primary objective and result in higher sequestration rates and less incremental oil production.

Two parts of the taxonomy framework can help inform the eligibility of carbon capture projects: 1) whether carbon capture for enhanced oil recovery qualifies as *existing* production and, 2) whether the project aligns with the facility-level emissions reduction and lifespan criteria in the framework.

Take first whether carbon capture facilities should be considered new or existing. On one hand, both traditional and newer forms of carbon capture would take place on formerly producing wells, which may satisfy the criteria laid out in Table 1. On the other, carbon capture for enhanced oil recovery results in higher emissions than if the same CO_2 was stored permanently without any additional oil production and therefore increases the risk of carbon lock-in. The US Department of Energy, for example, estimates that enhanced oil recovery can produce between 30 and 60 per cent of a reservoir's total reserves. However, to the extent that newer carbon capture for enhanced oil recovery applications produce less oil than traditional applications, these additional emissions would also be lower.

It is also important to put the potentially recoverable oil from carbon capture for enhanced oil recovery in context of the country's total potential. In Western Canada, for example, oil production from enhanced oil recovery would represent a small fraction of the oil sands' estimated 160 billion barrels of proven reserves and current production of 3.3 million barrels per day. If the total potential of carbon capture for enhanced oil recovery is fully developed, it could be equivalent to 1.5 years of current oil sands production.

The extent to which carbon capture projects for enhanced oil recovery align with the facility-level emissions reductions requirements in the taxonomy may, in part, depend on a project's sequestration rate. Projects with higher sequestration rates and less oil production would improve a project's total lifecycle emissions, especially when compared to conventional or oil sands production. There is, however, debate about how to properly account for the lifecycle emissions from carbon capture for enhanced oil recovery projects. Lifecycle emissions depend largely on the boundaries of analysis, where the CO_2 comes from, and whether the incremental oil from the project is considered to displace more carbon-intensive oil on the market.

Overall, more research and analysis is ultimately required on the potential eligibility of carbon capture for enhanced oil recovery projects in the Canadian taxonomy. Export Development Canada excluded all types of carbon capture for enhanced oil recovery from its 2022 sustainable bond framework, and the federal government has also made these projects ineligible for its new tax credits for carbon capture and sequestration investments. However, given the potential for new types of carbon capture for enhanced oil recovery projects to achieve higher sequestration rates, and the potential for carbon capture for enhanced oil recovery projects to help scale the technology for other applications, it is worth additional study for the purposes of the taxonomy's transition label.

Step 2: Demonstrate compliance with upstream Scope 3 criteria

If the project demonstrates compliance with Step 1, the next step is to ensure that a project's facility-level upstream Scope 3 emissions are consistent with 1.5°C pathways.[19]

Similar to Step 1, we propose using a dynamic threshold here, too. This approach could mirror the approach in Step 1, where sectoral emissions pathways are developed for different parts of the oil and gas supply chain. For example, if the issuer is a liquified natural gas facility or a blue hydrogen facility, it would need to demonstrate that its upstream suppliers of natural gas (extraction, processing, transport) comply with the Scope 1 and 2 benchmarks used for upstream natural gas in 1.5°C pathways. Projects would also need to demonstrate that upstream suppliers comply with the taxonomy's requirements around existing production.

It is important to note, however, that ensuring a project's upstream suppliers are aligned with 1.5°C pathways is more complicated than ensuring its own facility-level emissions meet the taxonomy thresholds. In some cases, a project and facility may have tens or hundreds of upstream suppliers that feed into its operations, making it challenging to comply with this type of analysis.

Yet it is also clear that these upstream emissions within the oil and gas sector are significant. A growing body of research, for example, shows how the lifecycle emissions from burning natural gas (for electricity, industry, or residential) can be on par with the lifecycle emissions of coal-fired electricity when accounting for methane leakage rates in upstream natural gas production. Accounting for these methane leaks in the taxonomy framework is therefore important for midstream projects that buy large volumes of

19 It is important to note that, like other aspects of this paper, the boundary of analysis for assessing greenhouse gas emissions is at the facility level (as defined under the federal Greenhouse Gas Emissions Reporting Program). This means that upstream Scope 3 emissions include all greenhouse gases associated with the inputs purchased and used for the facility's operations, regardless of whether the upstream suppliers are integrated within the issuer's corporate structure.

natural gas, such as liquified natural gas terminals, utilities, or blue hydrogen facilities. Other types of midstream oil and gas facilities, such as petrochemical manufacturing or pipelines, would also have high upstream Scope 3 emissions that need to be accounted for within the taxonomy framework.

Ensuring that upstream suppliers comply with emissions-intensity benchmarks aligned with 1.5°C pathways is a clear way to guard against these risks. More research, however, is required to better understand how issuers would operationalize this part of the taxonomy in practice. One potential solution is to develop priority areas in the short term where the facility must be able to demonstrate compliance. For example, if a downstream oil and gas company is looking to raise transition-labelled bonds or loans, they would need to demonstrate that the upstream producers of the fossil fuels used at their facility comply with stringent emissions-intensity thresholds (discussed in greater detail below).

BENEFITS OF THIS APPROACH

Complying with dynamic thresholds that decline over time addresses both the emissions of a project and its lifespan. The former proposal of using cash flow analysis achieved the same objective but necessitated making big assumptions about future oil and gas prices, along with facility-specific costs, far out into the future.

Oil and gas facilities already report their Scope 1 greenhouse gas emissions at the asset or facility level. It would be up to the issuer to demonstrate how the taxonomy-financed investment would reduce its emissions-intensity below the global benchmark.

The declining benchmark for upstream Scope 3 emissions would put the onus on the issuer to ensure that its suppliers are reducing their emissions. As discussed in Question 1, companies tend to have more agency over reducing their upstream emissions relative to their downstream emissions.

CHALLENGES WITH THIS APPROACH

Ensuring that a facility's major upstream suppliers align with 1.5°C pathways will require more data and analysis. The benchmarks proposed in this section focus exclusively on comparing a facility's emissions intensity with a sectoral benchmark using Scope 1 and 2 emissions. For this threshold to work, the Taxonomy Council and Custodian would need more, and higher-resolution, data on a facility's upstream Scope 3 emissions, which are both harder to estimate and less commonly disclosed by oil and gas companies. However, as climate-related disclosures become mainstreamed in Canada, this type of threshold in the taxonomy will become easier to implement.

Smaller issuers may struggle with providing the required data and analysis to receive a transition label. Most facilities in the oil and gas industry are already required to report their greenhouse gas emissions to provincial and federal programs; however, the taxonomy requires the additional step of estimating how a particular investment would impact these emissions over time, along with estimating their upstream Scope 3 emissions. Smaller issuers may have difficulty conducting this type of analysis and data collection.

As disclosure requirements become mainstreamed (for all companies, regardless of size), this may become a smaller issue. The Taxonomy Council and Custodian will need to assess best practices in other taxonomies to determine how (or whether) smaller issuers could be subject to less stringent criteria.

There will likely be a time lag between an issuance and the emissions reductions that are generated from the issuance. An issuer could be raising funds to make transformative investments to reduce their Scope 1 and 2 emissions (e.g., installation of carbon capture), but these improvements may not occur until several years in the future after the bond or loan has been issued. The hypothetical Project 3 in Figure 11 above illustrated this potential scenario.

The Taxonomy Custodian would ultimately need to develop guidance around what type of time lag is acceptable. One option, for example, would be to require that facilities meet or exceed the sectoral emissions-intensity benchmark by 2030.

Benchmark emissions-intensity pathways need to be updated over time, which may lead to inconsistencies with previous issuances (under less stringent criteria). These pathways will inevitably change over time as data improves, and as emissions-intensity pathways become clearer. The emissions-intensity curve depicted in Figure 11, for example, shows the relative emissions reductions required from facilities assuming the world's current emissions trajectory. If climate action in five or ten years is slower than what is required under 1.5°C pathways, it will (all else equal) increase the slope of the emissions-intensity curve for each sector (in other words, emissions reductions will need to happen faster and at a larger scale).

The taxonomy can update its emissions-intensity curves at regular and predictable intervals (perhaps every year or two); however, it may be the case that facilities that met the benchmark upon issuance no longer meet future (more stringent) benchmarks (see "Future research questions" below for more discussion on this point).

Ensuring that issuers provide clear, credible strategies for longer-term emissions reductions could be a significant challenge. In most cases, a single project's issuance will be insufficient to make an entire facility compliant with its emission intensity target for 2050. In the hypothetical examples in Figure 11, we illustrate facilities that make big, transformative investments in the near term followed by subsequent investments to keep the facility under the sectoral benchmark out to 2050. It would be unreasonable to expect that a single issuance today would put an entire facility in compliance with the emissions intensity benchmark for 2050.

At the facility level, one solution is to require issuers to disclose clear strategies for how the facility will make additional improvements to its emissions intensity in the future.

These strategies could include details on whether the technologies proposed to meet these thresholds are commercially available today ("safe bets") or are still in the development phase and unproven at scale ("wild cards"). Strategies could also include a preference for future-proofing, which enables a facility to cost-effectively adopt new technology in the future as it becomes more viable.

These facility-level disclosures would also need to fit within the broader company-level requirements of the taxonomy, including detailed transition plans. If the Canadian taxonomy adopts leading practices being developed in other jurisdictions, such as the UK Transition Plan Taskforce or the Climate Bonds Initiative, this would require oil and gas companies to disclose detailed plans for how they will achieve their net zero targets and respond to shrinking global demand. It could also include requirements to align lobbying and advocacy with corporate net zero goals, as advocated by the United Nations' High-Level Expert Group on the Net Zero Emissions Commitments of Non-State Actors.

Facility- and company-level strategies for achieving the 2050 objective would need to be vetted and approved by second-party opinion providers or third-party assurance providers.[20] Markets, not the Custodian, would then evaluate the credibility of these plans.

FUTURE RESEARCH QUESTIONS

The proposed approach raises several important research questions, detailed below.

1. **Even if issuers follow best practices in their facility- and company-level disclosure, discussed above, how can the taxonomy guard against issuers making commitments for future emissions reductions and not following through?** What are the consequences of failing to follow through on commitments? Are there international best practices (e.g., from the International Capital Markets Association) that successfully guard against this type of risk? Second-party opinion providers, third party assurance, and regular reporting can help mitigate this risk; however, is this enough?

   The Taxonomy Council and Custodian will need to develop guidelines that guard against intentional misuse of the transition label, but also anticipate unintentional circumstances. For example, there could be a situation where a company invests in a new technology to reduce emissions, receives the transition label to finance its adoption, and the technology fails to deliver on the intended outcomes. It could also be the case that improvements in measurement reveal emissions performance that no longer meets the taxonomy framework (for example, underestimated

20 Pre-issuance reviews can be conducted by multiple parties, offering different levels of certification. According to the Climate Bonds Initiative, second-party opinion providers assess the eligibility of particular projects or assets against the issuer's own green or transition bond framework, and sometimes provide a sustainability rating. Second-party opinion providers are typically ESG service providers or environmental consultants. Third-party assurance providers, by contrast, assess whether the green or transition issuance is aligned with a reputable international framework, such as the Green Bond Principles (GBP) or Green Loan Principles (GLP). These assessments are typically conducted by accounting or audit firms.

methane leaks). While it may not be possible for the Taxonomy Council to levy penalties on issuers that no longer meet their commitments, more research should be done on whether there are other types of disincentives that could be used.

These challenges with compliance are not just relevant to oil and gas activities—it is an issue relevant to all issuances made using the taxonomy. Strengthening the use of covenants in the bond or loan issuance process may be one way to provide greater assurance that companies will follow through on their planned investments. See Box 6 for more details.

Box 6: Challenges with ensuring taxonomy compliance

In the absence of a legislated standard for green and/or transition bonds in Canada, issuers seeking to bring to market such bonds to fund taxonomy-eligible projects are likely to do so in accordance with established global process guidelines, including the Green Bond Principles and the Climate Transition Finance Handbook published by the International Capital Market Association (ICMA). According to ICMA, the vast majority of sustainability bond issuances globally refer to its principles and guidelines to support comprehensive and transparent disclosure practices.

The ICMA guidelines are entirely voluntary, and no actions are taken against issuers that do not meet the guidance (aside from reputational risk). The other major global standard is the Climate Bonds Standard. It is a stricter standard, requiring issuers to align with the Climate Bond Initiative's taxonomy and engage an external reviewer from a pre-approved list. There are post-issuance requirements as well, including annual monitoring, verification, and reporting. The Standard's board can revoke the certification from a bond that is not in compliance. However, it is unclear what legal recourse investors have in this situation.

These voluntary standards—while helpful in raising the bar for issuances—point to the bigger challenge with ensuring that issuers comply with the thresholds and commitments made under the taxonomy. At present, use-of-proceed bond issuances do not incorporate contractual provisions related to their green or transition nature. Failing to allocate proceeds to the correct projects, or not making sufficient progress, does not trigger a default event, or any other kind of penalty. In fact, some prospectus filings do the opposite, including language to shield the issuer. The quote below is from a use-of-proceeds green bond issued by Brookfield in 2021.

> *Neither we nor the underwriters can provide any assurance that any Eligible Investments will satisfy investor criteria and expectations regarding environmental impact and sustainability performance. In particular, no assurance is given that the use or allocation of such proceeds for any Eligible Investments*

will satisfy, whether in whole or in part, any present or future investor expectations or requirements regarding any investment criteria or guidelines.

The other side of this challenge is the role of external reviewers and conflicts of interest. While external reviewers aim to uphold their reputation among both issuers and investors, their revenue comes from issuers. This raises concerns about the (dis) incentives that verifiers have when assigning ratings against a green or transition framework. Issuers are free to only engage with verifiers they think will rate them well. Incentive structures for credit rating agencies raise similar concerns.

Recent legislative developments in the EU may provide lessons here for Canada. The European Parliament is considering several major changes to how the European Green Bond Standard is applied. The most notable change is to Article 12, which would require the green bond factsheet to be fully incorporated into prospectus filings in the EU (where issuers are liable for false or misleading statements in a prospectus). Moreover, the addition of Article 12a could attach civil liability to the issuer in respect to the taxonomy-alignment of the proceeds. External reviewers will also need to register as a reviewer of European green bonds and meet several requirements.

Strengthening the use and application of covenants in bond and loan issuances may be another solution, which gives investors financial recourse if the issuer fails to achieve certain outcomes. A 2022 report by Moody's, for example, found that green, social, and sustainability bonds in Europe contained weaker covenants than non-green equivalents.

2. **To what extent should smaller issuers face less stringent reporting requirements for this criterion in the taxonomy framework?**

   Specifically, should smaller issuers be required to disclose the same type of upstream Scope 3 emissions data as larger issuers? Should they be expected to provide the same type of rigorous analysis, showing how a particular investment (whether carbon capture, or some other type of decarbonization technology) will align the facility's Scope 1 and 2 emissions with 1.5°C pathways?

   While there may be a case to make reporting requirements less stringent for smaller issuers at the outset, there is also value in creating a level playing field for all issuers under the taxonomy. Both perspectives were voiced by external stakeholders during the engagement sessions for this report.

   As disclosure of key climate metrics (e.g., Scope 1–3 emissions) becomes increasingly mainstreamed—whether through government requirements or market expectations—most companies will need to start collecting and reporting these data. Climate reporting and disclosure could become essential components to accessing capital, regardless of company size. Until this time, however, the Taxonomy Council and Custodian could consider a more gradual phase-in of requirements for small and medium-sized enterprises, similar to how mandatory disclosure rules in the United Kingdom have been implemented.

3. **Should emissions-intensity curves be determined based on global or domestic transition pathways?**

   This issue was not addressed in the SFAC Taxonomy Roadmap, but could have significant implications on the stringency of emissions intensity curves used in complying with this step in the taxonomy framework. It could also have broader implications for the credibility of the taxonomy in Canada, depending on how it is addressed.

   A fundamental goal of the taxonomy (which the Roadmap Report does cover extensively) is to keep global temperature rise to below 1.5°C and to ensure the framework reflects this goal. Canada also has its own domestic climate target of achieving a 40 to 45 per cent reduction in greenhouse gas emissions by 2030 and net zero emissions by mid century (from 2005 levels). These global and domestic goals, however, do not necessarily lead to the same sectoral pathways for emissions reductions.

   In practice, a global pathway would likely require a more stringent emissions pathway for Canada, particularly if it includes equity or fairness considerations for high-income countries to achieve net zero emissions before 2050. The Taxonomy Council and Custodian will also need to make important decisions about whether the Canadian taxonomy should be based on models that assume some degree of emissions overshoot (which would effectively make the emissions-intensity curve for each sector less steep) and the extent to which these models rely on carbon dioxide removal technologies (e.g., direct air capture) to achieve a 1.5°C degree target.[21]

   Developing formal guidance to address these issues—and their potential implications—requires more research and analysis. In particular, it requires assessing domestic sectoral emissions-intensity curves and comparing them against international estimates (such as those illustrated in Figure 10). Ultimately, the taxonomy should err on the side of the most robust and scientifically grounded emissions targets to ensure the international credibility of the taxonomy is protected.

4. **How will issuers operationalize the requirements on Scope 3 emissions and demonstrate that their upstream suppliers meet the taxonomy's specific emissions-intensity thresholds?**

   As mentioned above, some issuers may have tens or hundreds of upstream suppliers, particularly midstream and downstream facilities. Moreover, smaller issuers or those that are less vertically integrated may face greater challenges with getting

21 A 2022 report by IISD, for example, identifies 26 scenarios from three integrated assessment models that are consistent with 1.5°C degree pathways, have limited or no overshoot, and set limits on the use of CDR technologies based on guidance from the IPCC.

sufficient data from upstream suppliers. We propose a framework that initially focuses on the most material sources of upstream emissions, where data is often more readily available. As the Canadian taxonomy becomes more mature, it could encompass a wider range of upstream emissions.

Conclusion

The global race is on to attract the capital required to build competitive net zero companies and economies.

Canada needs a Climate Investment Taxonomy that can help create greater certainty around which projects and investments are aligned with Canada's long-term climate goals and global 1.5°C scenarios. With the large decarbonization challenge in front of us, all sectors, including heavy industry, will need to raise significant funds to transform their 'business as usual'.

Over 30 countries have developed or are in the process of developing taxonomies for green-label projects, but Canada is amongst the first jurisdictions to include a transition label within its taxonomy. The transition label has been designed to mobilize private finance towards decarbonizing heavy industry—and this includes projects that decarbonize the production of oil and gas. The controversial inclusion of oil and gas projects, despite their high emissions profile, is justified by the necessity to decarbonize historically dirty sectors significantly and rapidly. This paper, however, sets a high bar for what types of oil and gas projects could become eligible for the taxonomy's transition label while keeping Canada on 1.5°C pathways.

Using detailed criteria and metrics, the framework strikes a balance between promoting transformative investments and preventing carbon lock-in. These criteria include a project's status as an existing oil and gas facility, a project's ability to demonstrate significant reductions in Scope 1 and 2 emissions, and the extent to which a project's upstream suppliers' emissions also align with 1.5°C pathways. When taken in conjunction with the general requirements of the taxonomy (e.g., net zero targets, transition plans, and disclosure at the corporate level), the specific requirements ensure that only projects focused on drastically reducing emissions would qualify for taxonomy financing.

An effective and credible climate taxonomy must aim high and reach far. Canada has a unique opportunity to become a leader with its Climate Investment Taxonomy—providing first-of-its-kind guidance on the criteria for transition consistent oil and gas projects. Clear guidance on the transition label could particularly push Canada to the front of the race, and position its economy to be increasingly competitive in a low-carbon world.

Appendix

CCI'S OIL AND GAS WORKING GROUP MEMBERS

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GROUPS CONSULTED (AS OF JANUARY 2024)

Environmental NGOs
Regulators
International climate and energy agencies/organizations
Ratings agencies
The oil and gas industry (including companies and associations)
The financial sector
Indigenous organizations and First Nations
Carbon management companies