STATE OF MINNESOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

In the Matter of the Decommissioning Trust Fund for the Enbridge Energy, Limited Partnership Line 3 Replacement Pipeline

PUC Docket No. PL-9/CN-21-823

ADDITIONAL COMMENTS OF FRIENDS OF THE HEADWATERS

Thank you for the opportunity to submit additional comments on the Enbridge Line 3 (or 93) Decommissioning Trust. Friends of the Headwaters (FOH) stands by the recommendations in its previous comments about the appropriate structure for the trust, and will not repeat those arguments here. Instead, the goal of this comment is to bring new industry and government analysis showing that (1) decommissioning costs will likely be higher than the current Enbridge estimates; and (2) demand for Canadian Western Sedimentary Basin crude oil, and therefore demand for Enbridge's pipeline capacity, is likely to decline sooner and more sharply than previously estimated. It is therefore even more critical that the decommissioning cost estimate be reviewed again and revised upward, and that the pay-in period for the decommissioning trust be accelerated.

I. The decommissioning cost estimate needs to be revised upwards.

As we alerted the Commission in our last set of comments, the Canada Energy Regulator (CER) recently increased the Abandonment Cost Estimate for the pipelines it regulates by **79%**, from $10.4 billion in 2019 to $18.6 billion,[1] and is currently in the process of making significant upward adjustments to the "abandonment trust" contributions required under Canadian law. Since the time of the last comment, more details have become available:

A. Enbridge's abandonment cost estimates in Canada were nearly as low as those from the rest of the Canadian pipeline industry.

For Enbridge Pipelines Inc., the entity that controls the Enbridge Mainline pipelines in Canada, the original abandonment cost estimate was $1,743,200,000. At the close of 2020, the balance in its abandonment trust was $315,809,000.[2] The new estimate is $2,924,807,920, which is more than two-thirds higher, and means the Enbridge abandonment trust is now underfunded by around $2.5 billion.[3]

B. The reasons for the underestimates in Canada are just as applicable to estimates in Minnesota.

The process for estimating decommissioning costs for Line 3 in Minnesota was modeled on CER's approach, but it is not clear whether that meant the old way of estimating "abandonment" costs in Canada, the methodology the CER has now rejected or substantially modified. Originally, CER allowed the pipeline companies to make their own abandonment cost estimates, often based on estimates from back in 2010, and then making unit cost adjustments. Now, CER has a system for doing its own evaluation of geospatial pipeline and above-ground facility data, as well as geospatial land cover data, to make land use and crossing categorizations.

---

[1] Canada Energy Regulator (CER), *Decision in Brief: Pipeline Abandonment Funding Review* (June 15, 2023), https://www.cer-rec.gc.ca/en/about/news-room/decision-in-brief/2023/decision-in-brief-pipeline-abandonment-funding-review/decision-in-brief-pipeline-abandonment-funding-review.pdf. (Exhibit A).
[2] CER, *Previous Abandonment Cost Estimates,* Appendix G, https://www.cer-rec.ca/en/about/publications-reports/annual-report/2021/commission-report/appendix-g-abandonment-funding.html (Exhibit B).
[3] CER, *Five-Year Review of Abandonment Cost Estimates,* Appendix 1, https://docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90463/782060/4141002/4141003/4375090/C24949-5_Commission_–_Appendix_1_–_ACEs_for_all_companies_with_CER-regulated_pipeline_systems_–_ACE_Review_2021_and_SAM-COM_Review_2021_-_A8Q9R7.pdf?nodeid=4375193&vernum=-2 (Exhibit C).

CER has also substantially revised its cost categories and unit cost estimates for items like pipeline removal, or landscape reclamation and remediation.[4]

The documents made publicly available on Enbridge's cost estimates for the Minnesota portion of line 3 do not provide enough detail to understand whether or to what extent they deviate from CER's current practice. We do know that Enbridge's overall estimate has not changed much over the years, while Canada's estimates have increased substantially. Consequently, FOH recommends the DOC-DER and its consultant review the CER material from June 2023 to determine whether the total decommissioning cost estimate for Enbridge Line 3 (or 93) is too low. This should not wait for years to go by, as Enbridge has proposed.

C. The Enbridge abandonment trusts in Canada are seriously underfunded.

Right now, the CER information indicates that the abandonment trusts for Enbridge Mainline pipelines in Canada are over 80 percent unfunded. And with an annual contribution rate of 1/40, or 2.5 percent, those trusts will not be fully funded until well after the transition from fossil fuels has occurred and demand for oil transport capacity will be reduced to near-zero. Perhaps some Enbridge entity, in a largely non-fossil fuel future, will be able and willing to bear abandonment costs out of revenue from other sources. But it would be irresponsible for the Commission to conclude that such a scenario is likely. Because of the "unfunded liability" in Canada, there will be fewer Enbridge resources available to decommission the Minnesota portion of Line 93, and therefore more need to assure that all the funds that may be required are set aside soon enough.

[4] CER, *Five-Year Review of Abandonment Cost Estimates,* at 36-38 (June 2023), https://docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90463/782060/4141002/4141003/4375090/C24949-3_Commission_–_Report_of_the_Commission_of_the_Canada_Energy_Regulator_–_ACE_Review_2021_and_SAM-COM_Review_2021_-_A8Q9R5.pdf?nodeid=4375527&vernum=-2 (Exhibit D).

II. The pay-in period for the Decommissioning Trust should be no more than five years.

The costs of decommissioning and removing a crude oil pipeline are at 100 percent the day the pipeline goes into service. As a result, throughout any pay-in period the Commission allows, the trust will be underfunded, and there will be a risk that taxpayers, landowners, and the environment will have to foot the bill if the line shuts down.

Assuming that the Commission is prepared to put that risk on the public, the Commission must make an assessment – an educated guess – about when scenarios might develop where the pipeline will no longer be profitable enough for Enbridge to operate, hopefully with a margin of safety built in. The most recent data and the most recent analysis indicates that that date may not be far off.

As FOH has observed in previous comments, there is now a broad consensus that "peak demand" for crude oil globally either has already occurred, or will occur by 2030.[5] More recent reports have only moved up that date.

BP's most recent Energy Outlook, updated on July 5, 2023,[6] now projects that peak oil demand globally will occur no later than 2025,[7] and demand for oil will continue to drop over the next 25 years. Under a "net zero by 2050" assumption, BP sees global oil demand falling from just under 100 million barrels per day to around 20 million barrels per day by 2050, an 80 percent decline. The decline is not linear, but accelerates downward sharply after 2030.

According to BP, oil demand in emerging economies may remain broadly flat for longer, but that will be more than offset by the accelerating declines in oil use in the developed world.

---

[5] *See generally* International Institute for Sustainable Development (IISD), *Why Canada is Unlikely to Sell the Last Barrel of Oil,* Summary (Dec. 14, 2022) and citations, https://www.iisd.org/articles/deep-dive/why-canada-unlikely-sell-last-barrel-oil (Exhibit E).

[6] *bp Energy Outlook 2023 edition* (July 2023), https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2023.pdf (Exhibit F).

[7] BP's 2022 outlook predicted peak oil demand globally to occur around 2030.

That decline is primarily due to projected falling use of oil within road transport, with more efficient vehicles and the growing switch away from oil to alternative energy sources. The number of electric (including plug-in hybrid) cars and light-duty trucks will increase from around 20 million in 2021 to between 550 and 700 million (30-35% of the entire fleet) by 2035. In the 40% of the US economy covered by California standards (California and the 15 states that follow California's rules), two thirds of automobile sales in 2030 must be zero-emission vehicles, and in 2035, the requirement is 100%. The decline will not be a straight line, but will be the "S-curve" typical of new technology adoption scenarios.

The effect of falling demand on oil production will not be felt evenly around the world. At least 75 and 85 percent of the fall in oil production from now until 2050 will be borne by non-OPEC suppliers, because of the higher cost structure of non-OPEC production. OPEC's share of the ever-shrinking pie will grow to over half. U.S. tight oil production may increase in the short term, over the next ten years, but then it will be unable to compete and will fall to around 2 million barrels per day or less.

Canada's oil production will fare even worse. Canadian producers have reduced their costs since 2014, but Canadian oil is still much more costly than that of all the major Middle Eastern producers. Falling demand will drive out Canada's marginal producers first, but even its more efficient producers can expect no more than very low profits. Even the Canada Energy Regulator (CER) now acknowledges, in a net-zero-by-2050 scenario, oil and gas production in Canada will start declining in 2026.[8]

[8] *Canadian oil production could peak as early as 2026 in net-zero future, energy regulator says,* CBC Lite (June 20, 2023), https://www.cbc.ca/news/science/cer-energy-p-net-zero-1.6883225#:~:text=The%20regulator%20found%20that%20in,turns%20toward%20cleaner%20energy%20sources (Exhibit G).

As production drops, demand for transport capacity drops. That will not be felt evenly either. A considerable amount of oil transport from Canada is "locked in" by take-or-pay contracts, but, despite Enbridge's efforts, Enbridge's pipelines remain common access. Enbridge can try to retain market share by cutting shipper tolls, but it does not have a lot of other options once its market begins to decline.

As Enbridge revenues drop, its costs increase. In Canada, Enbridge is required to decommission or abandon pipelines as excess capacity increases, but, because its abandonment trust is underfunded, Enbridge will only be able to receive reimbursement for a small part of those costs. There will be a great deal of competition for Enbridge dollars, not just from its creditors overall, but from the need to pay for the nearly $3 billion in its Canadian abandonment cost estimate.

The only way Minnesota can protect itself in the kind of competitive environment is to make sure the Line 93 decommissioning trust is as fully funded as possible when the decline in Canadian oil production begins to accelerate. If the Minnesota decommissioning trust is fully funded, while the Canadian abandonment trust is not, Enbridge will have a strong incentive to take care of its Minnesota closure obligations first, because they can get revenue from doing the work in Minnesota, while they will be unable to do so in Canada. It should be this Commission's goal to make sure Minnesota's taxpayers, landowners, and environment come out ahead when the inevitable decline in the need for transport capacity of Canadian oil occurs.

FOH's recommendation, therefore, is that the pay-in period for the decommissioning trust be no more than five years, and that Enbridge be given every opportunity to fully fund the trust even earlier. Certainly, there can be no justification for Enbridge's proposed 40-year pay-in period,[9] and even the ten-year period floated during the last Commission public meeting on this subject puts Minnesota at an unnecessary risk. By 2034, it is not just plausible, but likely, that the Canadian oil industry will be in steep decline, as zero-emission vehicles take over and OPEC uses its pricing power to drive out remaining Canadian competition. The time to protect Minnesota's interests is now, by requiring full funding of the decommissioning trust as quickly as possible.

Respectfully submitted,

Scott Strand
Environmental Law & Policy Center
60 South Sixth St. Suite 2800
Minneapolis, MN 55402
sstrand@elpc.org
(612) 386-6409

Counsel for Friends of the Headwaters

[9] CER justifies its 40-year pay-in period by expressing concern that current shippers not end up paying the whole bill, while future shippers avoid those costs. There likely won't be "future shippers" under the most likely scenarios, but, in any event, there is no justification for conditioning Enbridge's obligations to fund a decommissioning trust on the willingness of shippers to pay, or delaying Enbridge's obligations until it can be 100% sure that it can pass all of its costs along to others.

DECLARATION OF SERVICE

Re: ***In the Matter of the Application of the Decommissioning Trust Fund for the Enbridge Energy, Limited Partnership Line 3 Replacement Pipeline***
MPUC Docket No. PL-9/CN-21-823

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

I, Scott Strand, hereby state that on July 28, 2023, I filed, by electronic eDockets, the attached **Additional Comments of Friends of the Headwaters,** and eServed or sent by U.S. Mail, as noted, to all parties on the attached service list.

I declare under penalty of perjury that everything I have stated in this document is true and correct.

/s/ Scott Strand __________________
Scott Strand

EXHIBIT A

Decision in Brief:

Pipeline Abandonment Funding Review

The Commission of the Canada Energy Regulator (CER) has issued updated preliminary abandonment cost estimates for all companies we regulate.

Using a new data-driven approach, we moved the estimates into a new system to calculate cost estimates that will improve efficiency and transparency. These improvements help make certain that companies have sufficient funds saved, or reserved specifically for, safely abandoning their pipelines in the future. By doing so, any associated costs will not be passed onto landowners, Indigenous Peoples or future Canadian taxpayers.

The pipeline abandonment funding review process

The CER reviews and updates abandonment cost estimates every five years to ensure accuracy. These reviews ensure that abandonment cost estimates are kept up-to-date and provide a solid estimate of the real-world costs each company will incur to abandon its pipelines. The pipeline abandonment funding review process refers to our five-year cycle of re-evaluating the cost estimates and funding related to the aband-onment of pipelines. This review applies to all companies with CER-regulated pipelines.

As part of this process, we assess abandonment cost estimates and how money is saved and collected. This helps ensure that all companies have enough money saved in advance for safe pipeline abandonment when it's no longer needed.

It's important to note that the actual costs of pipeline abandonment may differ from the estimated costs. Each company is responsible for covering the total cost even if the actual costs are higher. The abandonment cost estimates do not limit a company's responsibility for future abandonment costs. When abandoning a pipeline, the company must file an application with the CER. If approved, the Commission will also decide what activities are required to abandon the pipeline properly.

When a pipeline is permanently removed from service, it's called pipeline abandonment.

How money is saved and collected

As part of this review, we also looked at how companies save and collect money for pipeline abandonment. To ensure funds are available for abandonment, we require companies to provide financial guarantees (agreements from a third party to cover the costs if a company can't pay for any reason) or put money in trust. Only the CER can access the financial guarantees and trust fund money can only be released with CER approval.

Financial guarantees provided to the CER must cover the company's full abandonment cost estimate. Trusts, however, are funded over time, often through tolls paid by shippers. For trusts, the CER reviews company proposals for how many years it will take to fund future abandonment costs and how much money will be contributed to the trust each year. In this review, we have decided that all funds must be set aside in trusts by 2054 or earlier, depending on the company.

New approach to calculating abandonment cost estimates

In previous years, we provided companies with a set of factors they could use to calculate their own estimated abandonment costs. Those estimated costs were then reviewed and approved or modified by the Commission.

To increase consistency and transparency for everyone affected by CER-regulated pipelines, the CER now calculates company cost estimates instead of having companies calculate their own. The new standardized way of calculating the cost estimates uses publicly available geographic information system data.

This change also means that as new information becomes available, abandonment cost estimates can be updated more efficiently. Updated data will help improve the accuracy of the estimates over time and help make sure enough money is saved to protect the environment and nearby communities from any potential risks.

Updated pipeline abandonment cost estimates

In addition to introducing this new approach for calculating cost estimates, we have also reviewed and updated the factors used to calculate the estimates related to the activities needed to abandon pipelines safely. Using standardized calculations, the CER has provided preliminary estimates of each company's abandonment costs, suggesting that $18.6 billion may be required for future pipeline abandonment. This amount represents a significant increase compared to the final 2019 number of $10.4 billion.

For most companies, the CER's new preliminary estimates of their abandonment costs are higher than their previous estimates. This year's increased estimates are due to factors such as inflation, changes to company-owned infrastructure, and updated assumptions and costs. The previous abandonment cost estimates can be found in the 2021–22 Annual Report of the Commission of the Canada Energy Regulator – Appendix G: Abandonment Funding.

Next steps

We are issuing these preliminary abandonment cost estimates to companies as the first part of a two-step process. During the next step, regulated companies, Indigenous Peoples, landowners and other parties will have the opportunity to review the cost estimates. This is also when companies with trusts must submit additional information related to how much money they will contribute to their trusts each year and for how long. Also, companies using financial guarantees will soon have to file updated guarantees that reflect their new abandonment cost estimates.

Additional resources

- News Release
- Five-Year Review of Abandonment Cost Estimates and Set-Aside and Collection Mechanisms: Report of the Commission of the Canada Energy Regulator
- Information about pipeline abandonment

Decisions in Brief are prepared by the communications staff of the Canada Energy Regulator to help the public better understand Commission decisions. They do not form part of the Commission's official report.

Learn More

Decision | **News Release** | **Webpage**

EXHIBIT B

2021–22 Annual Report of the Commission of the Canada Energy Regulator – Appendix G: Abandonment Funding

Previous Page | Table of Contents | Next Page

All pipeline companies are required to follow the Canadian Energy Regulator Onshore Pipeline Regulations, which include a systematic approach to pipeline management, including abandonment. The Commission of the Canada Energy Regulator (the Commission) adjudicates applications to abandon pipelines (section 241 of the Canadian Energy Regulator Act (CER Act)) and ensures that companies have sufficient funds to pay for the eventual abandonment of pipelines (section 242 of the CER Act).

Companies' management includes the proactive management of their obligations relating to the set aside and collection of abandonment funds. The Commission reviews and assesses companies' abandonment cost estimates, which must be submitted every five years, and ensures that financial instruments are in place for those funds.

Canadians can be confident that the resources required to properly abandon CER-regulated pipelines have been, and continue to be, assessed, and set aside for that purpose.

Companies using Letters of Credit or Surety Bonds

Table G.1 lists all CER-regulated companies that are using a Letter of Credit or Surety Bond to fund their abandonment cost estimate and the amount of each associated financial instrument. The Amount of Instrument column reflects the latest abandonment cost estimates in 2018 dollars.

Table G.1

Company	Financial Instrument	Amount of Financial Instrument (in 2018 dollars except where noted)
1057533 Alberta Ltd.	Letter of Credit	855,173
2670568 Ontario Limited	Surety Bond	171,694
6720471 Canada Ltd.	Letter of Credit	45,000
Altagas Holdings Inc. for and on behalf of Altagas Pipeline Partnership	Surety Bond	1,875,849
ARC Resources Ltd.	Letter of Credit	1,893,204
Bonavista Energy Corporation	Letter of Credit	18,185
Caltex Resources Ltd.	Letter of Credit	291,292
Campus Energy Partners	Surety Bond	27,234,710
Canadian Natural Resources Limited	Surety Bond	909,876
Canadian-Montana Pipe Line Company	Surety Bond	300,000
Canlin Energy Corporation	Letter of Credit	101,557
Cenovus Energy Inc.	Letter of Credit	1,845,917

Company	Financial Instrument	Amount of Financial Instrument (in 2018 dollars except where noted)
Champion Pipe Line Corporation Limited	Letter of Credit	14,009,422
Cona Resources	Letter of Credit	1,320,396
Crescent Point Energy Corp.	Letter of Credit	346,878
Enercapita Energy Ltd.	Letter of Credit	1,527,861
ExxonMobil Canada Properties	Letter of Credit	7,985,252
FortisBC Huntingdon Inc.	Letter of Credit	115,754
Gear Energy Ltd.	Letter of Credit	217,155
Glenogle Energy Inc.	Letter of Credit	80,156
Great Lakes Pipeline Canada Ltd.	Letter of Credit	12,586,000
Husky Oil Operations Limited	Letter of Credit	8,387,654
Imperial Oil Resources Limited	Letter of Credit	1,414,710
ISH Energy Ltd.	Letter of Credit	3,046,923
Kiwetinohk Energy Corp.	Letter of Credit	362,000
LBX Pipeline Ltd.	Letter of Credit	3,198,336

Company	Financial Instrument	Amount of Financial Instrument (in 2018 dollars except where noted)
Leucrotta Exploration Inc.	Letter of Credit	241,490
Lignite Pipeline Canada Corp.	Surety Bond	1,426,320
NorthRiver Midstream G and P Canada Pipelines Ltd.	Letter of Credit	1,462,274
Obsidian Energy	Letter of Credit	922,150
Omimex Canada, Ltd.	Letter of Credit	132,950
OVINTIV Canada ULC	Surety Bond	2,063,970
OVINTIV Canada ULC	Letter of Credit	11,700,000
Pembina Energy Services Inc.	Letter of Credit	6,004,973
Pembina Prairie Facilities Ltd.	Letter of Credit	31,102,297
Pieridae Alberta Production Ltd.	Letter of Credit	332,477
Pine Cliff Border Pipelines Limited	Letter of Credit	704,000
Pine Cliff Energy Ltd.	Letter of Credit	127,250
Pipestone Energy Corp.	Letter of Credit	11,600
Pouce Coupé Pipe Line Ltd.	Letter of Credit	172,343

Company	Financial Instrument	Amount of Financial Instrument (in 2018 dollars except where noted)
Prospera Energy Inc. (Note: 2019 dollars)	Letter of Credit	90,726
Shell Canada Energy	Letter of Credit	4,920,047
Shell Canada Products Limited	Letter of Credit	259,288
Shiha Energy Transmission Ltd.	Letter of Credit	192,026
Steel Reef Pipelines Canada Corp.	Surety Bond	470,613
Sunoco Logistics Partners Operations GP LLC	Surety Bond	1,003,925
Tamarack Acquisition Corp.	Letter of Credit	43,980
TAQA North Ltd.	Letter of Credit	1,450,075
Tidewater Midstream	Letter of Credit	1,857,506
Tundra Oil & Gas Limited for and on behalf of Tundra Oil & Gas Partnership	Letter of Credit	72,812
Veresen Energy Pipeline Inc.	Letter of Credit	3,326,412
Veresen NGL Pipeline Inc.	Letter of Credit	1,761,889
Vermilion Energy Inc.	Letter of Credit	242,462

Company	Financial Instrument	Amount of Financial Instrument (in 2018 dollars except where noted)
Whitecap Resources Inc.	Letter of Credit	1,255,752
Windmill Dream	Letter of Credit	221,568
Winslow Resources	Letter of Credit	54,000
Yoho Resources Inc.	Letter of Credit	50,000
Zibi Community Utility	Letter of Credit	268,070

Companies using Trusts

Table G.2 lists all CER-regulated companies that are using a trust to fund their abandonment cost estimate, each associated abandonment cost estimate and the funds collected as of 31 December 2020. Note: Company annual trust filings, containing 2021 year closing balances, will be filed 30 April 2022.

Table G.2

Company	Abandonment Cost Estimate ($)	Collection Period (Years)	2020 Close balance ($) – Actual
2193914 Canada Limited	6,689,261	35	1,347,000
Alliance Pipeline Ltd.	364,940,000	40	75,592,599
Aurora Pipeline Company Ltd. (Plains)	57,840	40	20,551

Company	Abandonment Cost Estimate ($)	Collection Period (Years)	2020 Close balance ($) – Actual
Centra Transmission Holdings Inc.	22,226,090	40	6,346,182
Emera Brunswick Pipeline Company Ltd.	12,781,000	20	5,512,000
Enbridge Bakken Pipeline Company Inc., on behalf of Enbridge Bakken Pipeline Limited Partnership	22,300,000	25	4,265,000
Enbridge Pipelines (NW) Inc.	45,000,000	12	16,909,000
Enbridge Pipelines Inc.	1,743,200,000	40	315,809,000
Enbridge Southern Lights GP Inc. on behalf of Enbridge Southern Lights LP	177,900,000	40	26,214,000
Express Pipeline Ltd.	99,300,000	40	10,952,264
Foothills Pipe Lines Ltd.	244,720,000	30	61,194,000
Genesis Pipeline (Canada) Ltd.	3,114,576	40	1,389,678
Kingston Midstream Westspur	51,931,666	25	11,725,000
PKM Cochin ULC	28,000,000	20	11,536,459
Kinder Morgan Utopia Ltd.	1,104,300	21	275,652

Company	Abandonment Cost Estimate ($)	Collection Period (Years)	2020 Close balance ($) – Actual
Maritimes & Northeast Pipeline Management Limited	166,800,000	20	82,730,102
Montreal Pipe Line Limited	19,873,239	40	4,913,914
Niagara Gas Transmission Limited	6,871,346	35	1,353,000
Nova Gas Transmission Ltd.	2,535,333,000	30	663,643,000
Plains Midstream Canada ULC	50,347,731	40	15,731,207
Pouce Coupé Pipe Line Ltd.	7,597,783	15	7,358,721
Souris Valley Pipeline Limited	3,309,572	FF [a]	3,835,146
St. Clair Pipelines Management Inc.	1,359,792	35	298,005
Trans Mountain Pipeline Inc.	367,820,000	35	92,731,442
Trans Québec & Maritimes Pipeline (TQM) Inc.	115,500,000	25	37,597,000
TransCanada Keystone Pipeline GP Ltd.	268,100,000	25	84,614,000
TransCanada Pipelines Limited	2,904,930,000	25	1,013,555,000
Trans-Northern Pipelines Inc.	87,020,000	40	18,637,053

Company	Abandonment Cost Estimate ($)	Collection Period (Years)	2020 Close balance ($) – Actual
Union Gas Limited	103,187	FF [a]	107,266
Vector Pipeline Limited Partnership	8,500,000	35	1,141,000
Westcoast Energy Inc.	809,700,000	40	99,059,286
Westover Express Pipeline Limited (Note: 2021 dollars)	34,588,117	38	3,260,000

a FF = fully funded

Date modified:

2022-09-23

EXHIBIT C

Appendix 1 ACEs for all companies with CER-regulated pipeline systems

The table below includes all companies' Base Case 2021 ACEs calculated in Part 1. As Part 2 of the Review progresses and concludes, this table will be updated to include all companies' approved ACEs.

Company (ACE Holder)	Base Case 2021 ACE calculated in Part 1 of the Review		ACE approved in Part 2 of the Review	
	Link	Amount	Link	Amount
1057533 Alberta Ltd.	C24833	$12,446,590		
2193914 Canada Limited	C24834	$13,273,075		
2670568 Ontario Ltd.	C24835	$420,153		
6720471 Canada Ltd.	C24836	$983,805		
Alliance Pipeline Ltd., as general partner for and on behalf of Alliance Pipeline Limited Partnership	C24837	$618,505,926		
AltaGas Holdings Inc. for and on behalf of AltaGas Pipeline Partnership	C24838	$5,047,719		
ARC Resources Ltd.	C24839	$4,702,652		
Astara Energy Corp.	C24840	$367,799		
Aurora Pipe Line Company Ltd.	C24841	$437,588		
Bonavista Energy Corporation	C24842	$132,435		
Campus Energy Partners Operations Inc.	C24843	$38,104,259		
Canada Border Services Agency	C24844	$231,307		
Canadian Natural Resources Limited	C24845	$19,376,595		
Canadian-Montana Pipe Line Company	C24846	$503,051		
Canlin Energy Corporation	C24847	$1,661,771		
Cenovus Energy Inc.	C24848	$13,992,347		
Centra Transmission Holdings Inc.	C24849	$46,713,637		
Champion Pipe Line Corporation Limited	C24850	$21,300,872		
Chief Mountain Gas Co-op Ltd.	C24851	$105,915		
County of Vermilion River No. 24 Gas Utility	C24852	$153,743		
Crescent Point Energy Corp.	C24853	$1,377,035		
Emera Brunswick Pipeline Company Ltd.	C24855	$37,186,394		
Enbridge Bakken Pipeline Company Inc., on behalf of Enbridge Bakken Pipeline Limited Partnership	C24856	$36,072,478		
Enbridge Gas Inc.	C24857	$343,599		
Enbridge Pipelines (NW) Inc.	C24858	$159,951,322		
Enbridge Pipelines Inc.	C24859	$2,924,807,920		

Company (ACE Holder)	Base Case 2021 ACE calculated in Part 1 of the Review		ACE approved in Part 2 of the Review	
	Link	Amount	Link	Amount
Enbridge Southern Lights GP Inc. on behalf of Enbridge Southern Lights LP	C24860	$276,210,974		
Enercapita Energy Ltd.	C24861	$1,604,276		
Express Pipeline Ltd.	C24862	$107,681,525		
ExxonMobil Canada Properties	C24863	$12,876,056		
Foothills Pipe Lines Ltd. (includes Foothills Pipe Lines (South B.C.) Ltd.)	C24864	$424,953,661		
FortisBC Huntingdon Inc.	C24866	$140,321		
Gear Energy Ltd.	C24867	$416,262		
Genesis Pipeline Canada Ltd.	C24868	$11,543,770		
Great Lakes Pipeline Canada Ltd.	C24869	$19,010,136		
ISH Energy Ltd.	C24870	$10,980,612		
Kinder Morgan Utopia Ltd.	C24871	$1,518,431		
Kingston Midstream Virden Limited	C24872	$30,269,349		
Kingston Midstream Westspur Limited	C24873	$154,908,407		
Kiwetinohk Energy Corp.	C24874	$559,876		
LBX Pipeline Ltd.	C24875	$3,478,042		
Leucrotta Exploration Inc.	C24878	$551,811		
Lignite Pipeline Canada Corp.	C24879	$632,046		
Many Islands Pipe Lines (Canada) Limited	C24880	$101,194,689		
Maritimes & Northeast Pipeline Management Ltd.	C24882	$197,302,480		
Milk River Pipeline Ltd.	C24883	$12,304,352		
Minell Pipeline Limited	C24884	$7,070,983		
Montreal Pipe Line Limited	C24885	$67,590,658		
Niagara Gas Transmission Limited	C24886	$9,881,182		
NorthRiver Midstream Canada Partner Limited, as general partner and on behalf of NorthRiver Midstream Canada LP	C24888	$2,593,319		
NorthRiver Midstream G and P Canada Pipelines Inc., as general partner and on behalf of NorthRiver Midstream G and P Canada Pipelines Limited Partnership	C24889	$4,925,731		
NOVA Gas Transmission Ltd.	C24890	$5,638,704,250		
Obsidian Energy Ltd.	C24891	$2,634,101		
Omimex Canada, Ltd.	C24892	$120,274		
Ovintiv Canada ULC	C24893	$19,482,354		
Pembina Energy Services Inc.	C24894	$9,264,651		

Company (ACE Holder)	Base Case 2021 ACE calculated in Part 1 of the Review		ACE approved in Part 2 of the Review	
	Link	Amount	Link	Amount
Pembina Prairie Facilities Ltd.	C24895	$62,504,287		
Pieridae Alberta Production Ltd.	C24896	$565,257		
Pine Cliff Border Pipelines Limited	C24897	$5,591,726		
Pine Cliff Energy Ltd.	C24898	$410,312		
Pipestone Energy Corp.	C24899	$20,840		
PKM Cochin ULC	C24900	$194,798,151		
Plains Midstream Canada ULC	C24901	$247,520,781		
Portal Municipal Gas Company Canada Inc.	C24903	$333		
Pouce Coupé Pipe Line Ltd.	C24904	$30,775,293		
Prospera Energy Inc.	C24905	$196,209		
SCL Pipeline Inc.	C24906	$753,730		
Shiha Energy Transmission Ltd.	C24907	$3,745,852		
Souris Valley Pipeline Limited	C24908	$12,013,222		
Spartan Delta Corp.	C24909	$221,543		
St. Clair Pipelines Ltd.	C24910	$1,202,043		
Steel Reef Infrastructure Corp.	C24911	$7,525,318		
Strathcona Resources Ltd.	C24912	$732,028		
Sunoco Logistics Partners Operations GP LLC on behalf of Sunoco Pipeline LP	C24913	$1,227,668		
Surge Energy Inc.	C24914	$1,603,781		
Tamarack Acquisition Corp.	C24915	$374,008		
TAQA NORTH by its managing partner TAQA NORTH Ltd.	C24916	$1,515,511		
Tidewater Midstream and Infrastructure Ltd.	C24917	$5,217,621		
Trans Mountain Pipeline ULC	C24918	$912,696,666		
Trans Québec and Maritimes Pipeline Inc.	C24919	$172,227,840		
TransCanada Keystone Pipeline GP Ltd.	C24920	$423,004,118		
TransCanada PipeLines Limited	C24921	$4,293,599,744		
Trans-Northern Pipelines Inc.	C24922	$183,027,567		
Tundra Oil & Gas Limited for and on behalf of Tundra Oil & Gas Partnership	C24923	$290,790		
Twin Rivers Paper Company Inc.	C24924	$2,875,261		
Vector Pipeline Limited on behalf of Vector Pipeline Limited Partnership	C24925	$8,241,872		
Veresen Energy Pipeline Inc.	C24926	$4,937,088		
Veresen NGL Pipeline Inc.	C24927	$2,662,203		

Company (ACE Holder)	Base Case 2021 ACE calculated in Part 1 of the Review		ACE approved in Part 2 of the Review	
	Link	Amount	Link	Amount
Westcoast Energy Inc.	C24929	$882,663,888		
Westover Express Pipeline Limited	C24930	$51,384,542		
Whitecap Resources Inc.	C24931	$1,951,439		
Yoho Resources Inc.	C24932	$205,026		
Zibi Community Utility	C24933	$214,200		
Total		**$18,607,102,324**		

EXHIBIT D

Canada Energy Regulator Régie de l'énergie du Canada

Five-Year Review of Abandonment Cost Estimates and Set-Aside and Collection Mechanisms 2021

Report of the Commission of the Canada Energy Regulator

Presiding Commissioner – S. Luciuk
Commissioner – M. Watton
Commissioner – M. Chartier

June 2023

The Commission has decided to use the *Abandonment in Place* cost category description proposed in ACE Paper 3 because Participants' submissions indicated that it accurately describes the costs associated with abandoning a pipeline in place. The cost category description is provided in **Table 8.** The *Abandonment in Place* cost category description includes some revisions when compared to the *Basic Abandonment in Place* cost category from Base Case 2010. First, the cost category no longer includes costs related to remediation, reclamation, and restoration for pipelines assumed to be abandoned in place. Base Case 2021 includes new cost categories related to remediation, reclamation, and restoration (see **Section 4.4.5**). Second, the *Abandonment in Place* cost category does not consider terrain as a factor for estimating costs to abandon in place. Companies' submissions indicated support for removing terrain as a factor, with some companies submitting that abandonment in place costs are not as impacted by terrain conditions as are pipeline removal costs.

ACE Paper 3 asked questions regarding the appropriate segmentation interval (i.e., the distance between plugs) to be used when establishing unit costs for the *Abandonment in Place* cost category, and how companies considered these intervals in their unit costs submissions. Alliance Pipeline Ltd. indicated that it applied a segmentation interval of 10,000 metres to its costs. Other companies said that they did not apply specific segmentation intervals when developing their unit costs because they assumed that abandonment activities at above-ground facilities and crossings would result in reasonable segmentation. Landowner associations suggested that segmentation should occur at all property boundaries.

The Commission has decided not to assign a specific segmentation interval to this cost category. The Commission agrees with companies that actual segmentation locations will vary greatly for each pipeline depending on terrain; environmental and socio-economic considerations; and consultation with landowners, Indigenous Peoples, and other stakeholders at the time of abandonment. Recent abandonments of CER-regulated pipelines demonstrate that segmentation is rarely used and is usually only proposed for longer pipelines. The unit costs associated with the *Abandonment in Place* cost category can be adjusted in future ACE reviews, if warranted, based on new information from actual abandonments.

More generally, in establishing unit costs for the *Abandonment in Place* cost category, the Commission has taken into consideration the range of unit costs provided by companies. The chosen Base Case 2021 unit costs generally are close to or slightly less than the mid-range of the total costs provided by companies for each pipeline diameter category and reflect a steady increase of cost with increase in pipeline diameter. The unit cost for very small diameter, non-steel pipelines is half of the unit cost for very small diameter, steel pipelines as the expected difference in such abandonment in place costs was reflected in the unit costs provided by companies for the very small diameter pipeline categories.

4.4.4 Pipeline Removal

<u>Commission decision</u>

The Commission has decided that the *Pipeline Removal* cost category to be used in the 2021 ACE Calculation Method will be limited to activities associated with pipeline removal and no longer include costs related to land reclamation. Unit costs for *Pipeline Removal* vary by pipeline diameter.

The Commission has decided to use the cost category description proposed in ACE Paper 3. The description and calculation method for the cost category are provided in **Table 10.** The Base Case 2021 unit costs established for the cost category are shown in **Table 11.**

Table 10 – Pipeline Removal (description and method)

Cost category	Description of costs	Calculation method
Pipeline Removal	• Mobilization and demobilization of equipment and personnel • Removal of buildings and equipment • Right-of-way clearing • Topsoil stripping • Excavation of pipelines and appurtenances (including cathodic protection) • Cutting and capping of pipelines • Stockpiling, loading, hauling, and disposal of removed pipelines, buildings, and equipment • Backfill and compaction of disturbed soils	Calculated by multiplying the length of the pipeline system assumed to be removed, by pipeline diameter, by the applicable Base Case 2021 unit costs shown in **Table 11**. These costs are then added up to obtain the total estimated cost for the cost category.

Table 11 – Pipeline Removal (unit costs)

	Very small diameter pipe (not steel)	Very small diameter pipe (steel)	Small diameter pipe (all materials)	Medium diameter pipe (all materials)	Large diameter pipe (all materials)
Pipeline Removal ($/km)	$12,000	$30,000	$80,000	$200,000	$350,000

See **Table 5 for pipe diameter measurements*

<u>Reasons of the Commission</u>

As was proposed in ACE Paper 3, the Commission has decided to establish a single cost category for pipeline removal in the 2021 ACE Calculation Method for pipeline removal activities at the time of abandonment, with different unit costs for each pipeline diameter category.

To increase transparency of the pipeline removal land restoration costs in an ACE that were previously accounted for in Base Case 2010 Cost Category 5b, the Commission has created separate cost categories in the 2021 ACE Calculation Method for remediation and for reclamation and restoration costs. Participants' submissions generally indicated agreement with this approach, although some submitted that there were no benefits to splitting such costs. The Commission's reasons for the new *Remediation*, and *Reclamation and Restoration* cost categories are found in **Section 4.4.5**, and those reasons include consideration of the comments received in response to questions asked in the *Pipeline Removal* section of ACE Paper 3.

The Commission has also decided not to use terrain as a factor for estimating pipeline removal costs in the 2021 ACE Calculation Method, as was done in Base Case 2010 for Cost Category 5b. The Commission agrees with Participants' submissions that pipeline removal in difficult terrain could result in higher pipeline removal costs. However, it is a complex task to determine how geospatial terrain datasets can best be applied to the GIS to categorize terrain along pipeline systems and meaningfully determine what terrain characteristics would result in differences in pipeline removal costs. The Commission is of the view that further exploration of this topic would be required to incorporate terrain as a factor and this may be considered as part of future ACE reviews.

The Commission notes that Cost Category 5a in Base Case 2010 also included factors to be applied to reduce pipeline removal costs if companies have more than one pipeline in the same ditch. In ACE Paper 3, the possibility of abandonment cost reductions was considered, including for pipeline removal costs, where multiple pipelines are in the same corridor. The Commission has decided not to apply such cost reductions in the 2021 ACE Calculation Method. The Commission’s reasons for this decision are found in **Section 4.5.2**.

The Commission has decided to use the *Pipeline Removal* cost category description proposed in ACE Paper 3 because Participants’ submissions indicated that it accurately describes the costs associated with removing pipeline. The cost category description is provided in **Table 10.**

In establishing the *Pipeline Removal* costs, the Commission has taken into consideration the range of unit costs provided by companies. The chosen Base Case 2021 unit costs are generally close to or slightly less than the mid-range of the total costs provided by companies for each pipeline diameter category and reflect a steady increase of cost with increase in pipeline diameter. The unit cost for very small diameter, non-steel pipelines is less than half of the unit cost for very small diameter, steel pipelines as the expected difference in such pipeline removal costs was reflected in the unit costs provided by companies for the very small diameter pipeline categories.

4.4.5 Remediation, and Reclamation and Restoration

<u>Commission decision</u>

The Commission has decided to establish separate cost categories for *Remediation* and for *Reclamation and Restoration* in the 2021 ACE Calculation Method. Unit costs for *Remediation* vary by the type of commodity carried by the pipeline. Unit costs for *Reclamation and Restoration* vary according to whether the pipeline is assumed to be abandoned in place or removed. Further, the unit costs for the *Reclamation and Restoration (Pipeline Removal)* subcategory also vary by pipeline diameter.

The Commission has decided to revise the cost category descriptions proposed in ACE Paper 3 as described in the reasons below. The descriptions are provided in **Table 12** with the calculation methods. The Base Case 2021 unit costs established for the cost category are shown in **Table 13**.

Table 12 – Remediation, and Reclamation and Restoration (description and method)

Cost category	Description of costs	Calculation method
Remediation	• Remediation of contaminated soil, sediment and/or groundwater, where necessary, including monitoring and testing. • Includes, but is not limited to: excavation, hauling, and disposal of contaminated soil; backfilling; field sampling and analytical testing; and follow-up monitoring	Calculated by multiplying the total length of the pipeline system, by commodity type, by the applicable Base Case 2021 unit costs shown in **Table 13**. These costs are then added up to obtain the total estimated cost for the cost category.
Reclamation and Restoration	• Assess, reclaim and restore the ground surface (e.g., soil, vegetation) for the length of the pipeline right-of-way (not just at areas disturbed during abandonment activities) to equivalent land use of adjacent lands (or other relevant reclamation objective such as critical habitat for specified wildlife species at risk, landowner requests, Indigenous cultural values, etc.) • Alleviate any noted soil and/or vegetation issues (e.g., sub-soil compaction, subsidence) • Seeding • As relevant, planting of trees and shrubs to restore critical habitat for wildlife species at risk and implementing access control measures	**Abandonment in Place:** Calculated by multiplying the total length of the pipeline system assumed to be abandoned in place by the applicable Base Case 2021 unit cost shown in **Table 13**. **Pipeline Removal:** Calculated by multiplying the length of the pipeline system assumed to be removed, by pipeline diameter, by the applicable Base Case 2021 unit costs shown in **Table 13**. These costs are then added up to obtain the total estimated cost for the cost category.

EXHIBIT E

The Bottom Line

Why Canada Is Unlikely to Sell the Last Barrel of Oil

Aaron Cosbey[1]

December 2022

Summary

- Canadian producers are vulnerable to two foreseeable threats: declining global demand for oil and falling oil prices.
- Almost all Canadian exports go to U.S. refineries. This reliance on captive buyers will initially shield Canada from the worst of the decline in demand, but this buffer will not last.
- Nothing will shield Canada from global oil price drops and volatility. Pressure on Organization of Petroleum Exporting Countries-plus discipline as members rush to increase oil production in the face of declining demand will result in prices that are low and even more volatile than normal.
- Canadian oil producers' environmental, social, and governance performance will not help preserve Canada's market share, since it does not matter to the refineries buying the product.
- Marginal producers will not survive in the post-peak market, and efficient producers will see low profits, remitting low royalties and taxes. In line with history, large numbers of workers will lose their jobs in the sector.
- Canada cannot afford to delay support for diversifying into sectors that can replace oil as an engine of economic prosperity.

[1] Acknowledgements: Richard Masson and Nichole Dusyk generously reviewed this briefing. Any errors or omissions remain the responsibility of the author.

Oil demand and oil prices are currently booming, spurred by under-investment in exploration and an unexpected demand surge as COVID-19 restrictions were lifted, and greatly exacerbated by the Russian invasion of Ukraine. Nonetheless, almost all analysts see global demand for oil peaking around 2030 (BP, 2022; DNV, 2022; International Energy Agency [IEA], 2022; McKinsey, 2022; Rystad Energy, 2022). Recent International Institute for Sustainable Development [IISD] analysis predicts falling demand by 2030 and significant declines thereafter as new technologies and ambitious climate policies eat into all of oil's major end uses (Cosbey, 2022).

It is not obvious, though, what that means for Canadian oil producers. Will they thrive even as the global market shrinks? Will Canadian environmental, social, and governance (ESG) credentials help grow or maintain the country's market share? Will they, as suggested by former Premier of Alberta Jason Kenney, help Canada buck global circumstances and sell the proverbial last barrel of oil (Braid, 2022)?

This policy brief explores four factors that define the answers to those questions:

- The destination of Canada's crude oil exports
- Whether Canada can win markets with its ESG credentials
- Whether Canada can win markets on price
- What to expect from Canada's global competitors

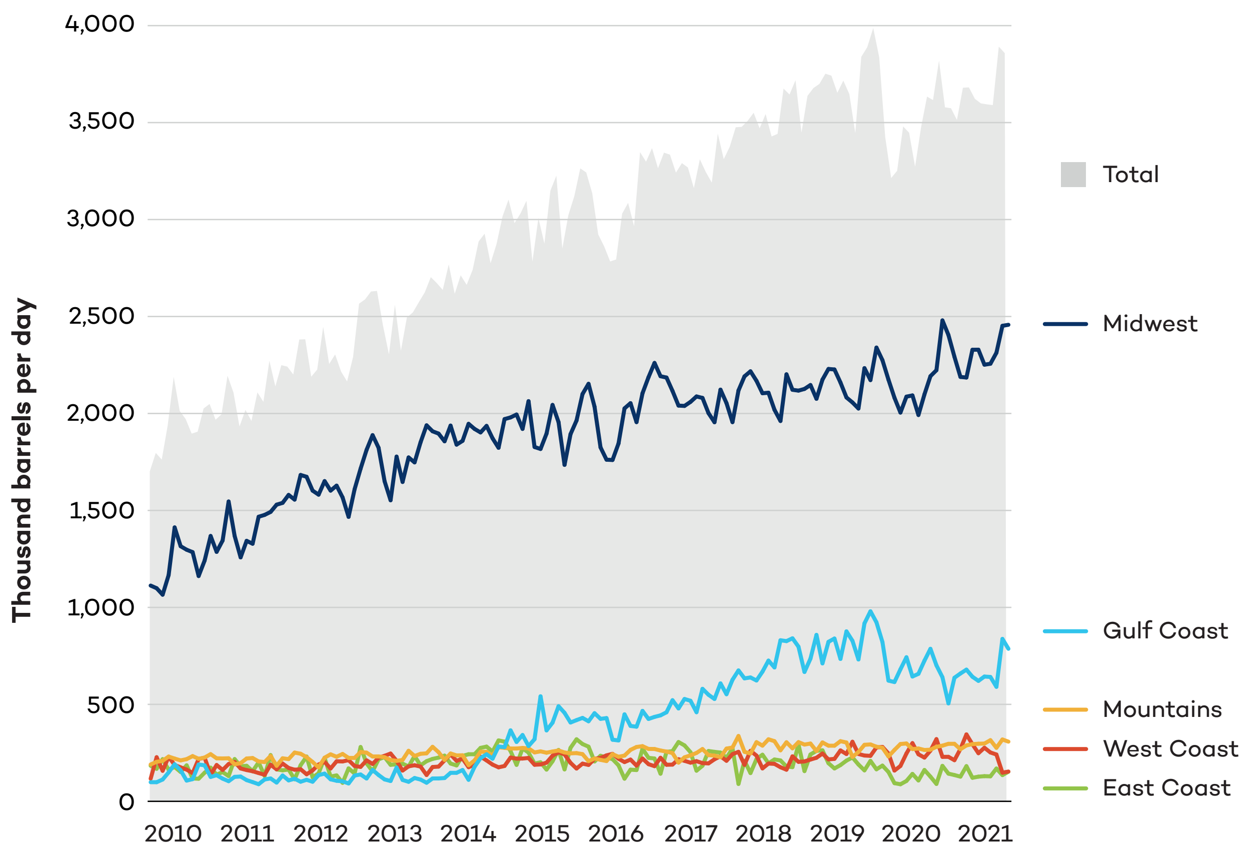
Almost All of Canada's Oil Exports Go to U.S. Refiners

In 2021, Canada exported 3.3 million barrels a day (bpd) of crude oil, or 80% of domestic production (Canada Energy Regulator, 2022; UN Comtrade, 2021). Over 94% of those exports went to the United States, and 80% were in the form of heavy crude of the type produced in Western Canada's oil sands (Canada Energy Regulator, 2022).

Figure 1 shows where those exports went: overwhelmingly to Midwest refiners in Illinois and Minnesota (primarily through the Enbridge and Keystone pipeline systems), but increasingly also to Gulf Coast refiners as U.S. pipeline reversals and transport by rail have increased Canadian producers' ability to reach them.

Several major Midwest refineries and some Gulf Coast refineries are deliberately set up to refine oil sands-type heavy crude. Many in the Midwest have made recent multibillion-dollar investments in capacity specifically designed to do so. For the Midwest refineries, Canada is the only viable source of crude feedstock; they do not have tidewater access to import crude from other suppliers (or to export their final product). Gulf Coast refiners can import crude by tanker, but other global sources of heavy crude—primarily in Mexico and Venezuela—have dropped to almost negligible levels of production, so Canada is a critically important source.

Figure 1. U.S. refining district destinations for Canadian crude exports



Source: Canada Energy Regulator, 2022.

What will those export patterns mean for Canada when global demand drops? Canadian oil exporters are potentially vulnerable to two forces: lower demand and lower price. On demand, Canada is partially insulated from global trends because it mostly sells to Midwest U.S. refiners whose output is consumed in the United States. But Canada is not completely insulated from drops in global demand for three reasons:

- U.S. demand itself will be dropping. The U.S. Inflation Reduction Act is projected to shave 2.1 million bpd off U.S. demand for petroleum products by 2030 and 4.1 million bpd by 2035, relative to 2021 U.S. consumption of 18.6 million bpd of crude (Jenkins et al., 2022).[2] Those numbers are likely underestimates since they do not factor in the ban on the sale of conventional light cars and trucks in California by 2035 or the follow-on announcements that will come from 15 other states with linked regulatory regimes (Gearino, 2022).

[2] A 42 U.S.-gallon barrel of crude is refined into 45 gallons of petroleum products.

- Though U.S. demand decreases won't necessarily translate directly into reduced Canadian imports (the complex modern refineries to which Canada sells would not likely be the first to cut production), the pressure for such cuts will be significant. U.S. refiners exported 46% of their production in 2021 (U.S. Energy Information Administration, n.d.), and they will be selling into a declining global market.
- A small but increasing amount of Canadian crude finds its way to markets beyond the United States through the Gulf Coast in flows that reached almost 300,000 bpd in 2021 (Kelly & Williams, 2022). The expansion of the Transmountain pipeline to the Canadian West Coast would, if completed, add another 600,000 bpd of non-U.S. export capacity. Combined, that would amount to 27% of total 2021 exports.

The conclusion is that Canada's U.S. export patterns provide a buffer but do not shield it much from lower demand for its exported crude oil as global demand drops.

Canada is also directly vulnerable to the price impacts of a global decrease in demand, and its U.S. export markets do little to shield it from those impacts. Prices are, to a large extent, set in a global market. Those prices are set both by demand and supply, however, so it matters what Canada's global competitors will do as demand falls—a topic that is explored below.

ESG Credentials Will Not Preserve Canadian Oil's Market Share

If Canada were vying to sell the proverbial last barrel of oil, would it matter how its oil was produced? Would greenhouse gas (GHG) intensity matter, for example, or would it matter whether it was considered "ethical" or produced to high ESG standards? The short answer is: probably not.

For some products, production methods impact marketability. At comparable price and quality, final consumers will favour "green" and ethically produced products. For goods like food, clothing, and electronics, a variety of labelling schemes allow consumers to choose, even to pay a premium for labelled products (Voora et al., 2022). But for commodities like oil, the situation is different. When refined Canadian oil is finally sold at the pumps, it is indistinguishable from other gasoline, and tracking the source at the retail level would be daunting. The original customers are mostly U.S. refiners dependent on the supply of heavy Canadian crude, as detailed above, who focus on quantity, quality, and price—not ESG. ESG considerations clearly matter a great deal to oil sector *investors* (Flavelle, 2020; Graney, 2021), but they do not preoccupy most *customers*. While investors influence companies' ability to finance expansion, new projects, and infrastructure, they don't buy the final product, and therefore their opinions don't directly affect a company's market share. This will be especially true in the context of a shrinking market in which Canadian producers will not need to expand operations to compete for the few remaining buyers. Canadian crude oil's emissions intensity would matter if the United States implemented a clean fuel standard governing the life-cycle carbon content of transportation fuels such as gasoline. By design, such a standard would reduce the market share of crude oil produced at high emissions intensity, including most of Canada's U.S. exports (see Box 1). California, Oregon, and Washington have clean fuel standards in place. But, while such a policy has been suggested by legislators (House Select Committee on the Climate Crisis, 2020; Senate Democrats Special Committee on the Climate Crisis, 2020), it would face strong opposition from the domestic refining sector and raise the price of gasoline for American drivers, making it unlikely to pass in the foreseeable future.

Box 1. How does Canadian crude oil measure up on GHG emissions intensity?

It is complicated to judge how the GHG intensity of Canadian oil production as a whole stacks up against international competitors because Canada's different producers use different production methods, with very different emissions-intensity profiles (Birn & Crawford, 2020). In terms of emissions intensity, for oil sands, in-situ mining is much worse than surface mining, and both are much worse than conventionally produced crude oil.

That said, one of the most prominent international benchmarking exercises for the GHG intensity of oil production suggested that Canadian crude oil production is, on average, among the most polluting. Canada's mean score was ranked fourth worst in the world for 2015—besting only Algeria, Venezuela, and Cameroon (Masnadi et al., 2018). That high score is heavily influenced by emissions-intensive oil sands operations, which produce over 65% of Canada's crude oil.

Beyond the question of whether ESG matters for Canadian oil's market share is the more basic matter of whether Canada's producers are, in fact, world leaders on ESG criteria, as claimed by some industry groups and pundits (Canadian Association of Petroleum Producers, n.d.; Dziuba et al., 2020).

On environmental performance, Box 1 makes it clear that Canada's overall GHG intensity of production is not world class. Beyond emissions, Canada's oil sands operations have been dogged for years by a record of serious water and air pollution impacts (Alberta Environmental Monitoring Panel, 2011; Leahy, 2019; Liggio et al., 2016). Those impacts were singled out as disproportionately affecting Indigenous peoples by the United Nations Special Rapporteur on the implications for human rights of the environmentally sound management and disposal of hazardous substances and wastes (Tuncak, 2020).

Oil sands development has been responsible for extensive impacts on the traditional territories of many First Nations in Alberta, in violation of treaty rights and without proper consultation or respect for basic principles such as cumulative effects management (Lower Athabasca Regional Plan Review Panel, 2015). In many instances, the industry's consultations and impact assessments with respect to Cree, Dene, and Métis rights have been designed in a manner to expedite oil sands development (Baker & Westman, 2018). Members of many Nations in the region, such as Athabasca Chipewyan First Nation and Fort McKay First Nation, have denounced these impacts for decades. Additionally, the Beaver Lake Cree Nation has an ongoing lawsuit against the governments of Alberta and Canada on the basis that the cumulative impacts of this industrial development violate their Treaty 6 rights (Beaver Lake Cree Nation, n.d.).

Canadian producers' mismanagement of the end of the oil and gas project life cycle should also be considered. In Alberta, as of September 2022, 3,309 oil and gas sites are considered orphaned, meaning the original owners failed to fulfill their responsibility for costly end-of-life decommissioning and restoration (Orphan Well Association, 2022a). Many of those sites were strategically sold to insolvent operators (Lewis et al., 2018). Responsibility for them now falls to the industry-funded Orphan Well Association, but current industry contributions are grossly inadequate. The Association has CAD 169 million in assets against orphaned sites that it estimates will cost almost CAD 700 million to clean up (Orphan Well Association, 2022b). Liability estimates for all existing sites are much higher, reaching up to CAD 260 billion (De Souza et al., 2018). The difference has partly been borne by taxpayers through government loans and bailouts to treat inactive and orphaned wells (Government of Canada, 2020), violating the polluter-pays principle. But most orphan wells remain unremediated, and a large proportion of "active" wells are, in fact, inactive but not declared as such, meaning the farmers and ranchers on whose land they sit suffer the environmental and economic consequences (Boychuk et al., 2021).

Similarly, it is arguably an ESG issue that some Alberta oil and gas companies owe hundreds of millions of dollars in unpaid municipal taxes (French, 2022) and tens of millions of dollars in unpaid lease payments to landowners (Riley, 2022).

Some insist the last barrel of oil should be sold by a country like Canada that respects democracy and human rights (Braid, 2022). However, this is largely beside the point: while Canada as a country may have better ESG institutions than many of the world's top oil-producing countries, ESG criteria traditionally centre on the behaviour of the firm in question, not the government policies where they happen to operate. Some Canadian oil producers score well on ESG criteria, and others score poorly (CSRHub, n.d.).

Ultimately, however, whether Canada's producers' ESG rating *should* preserve its market share is irrelevant. As argued above, it won't; buyers of Canadian oil don't discriminate on ESG grounds.

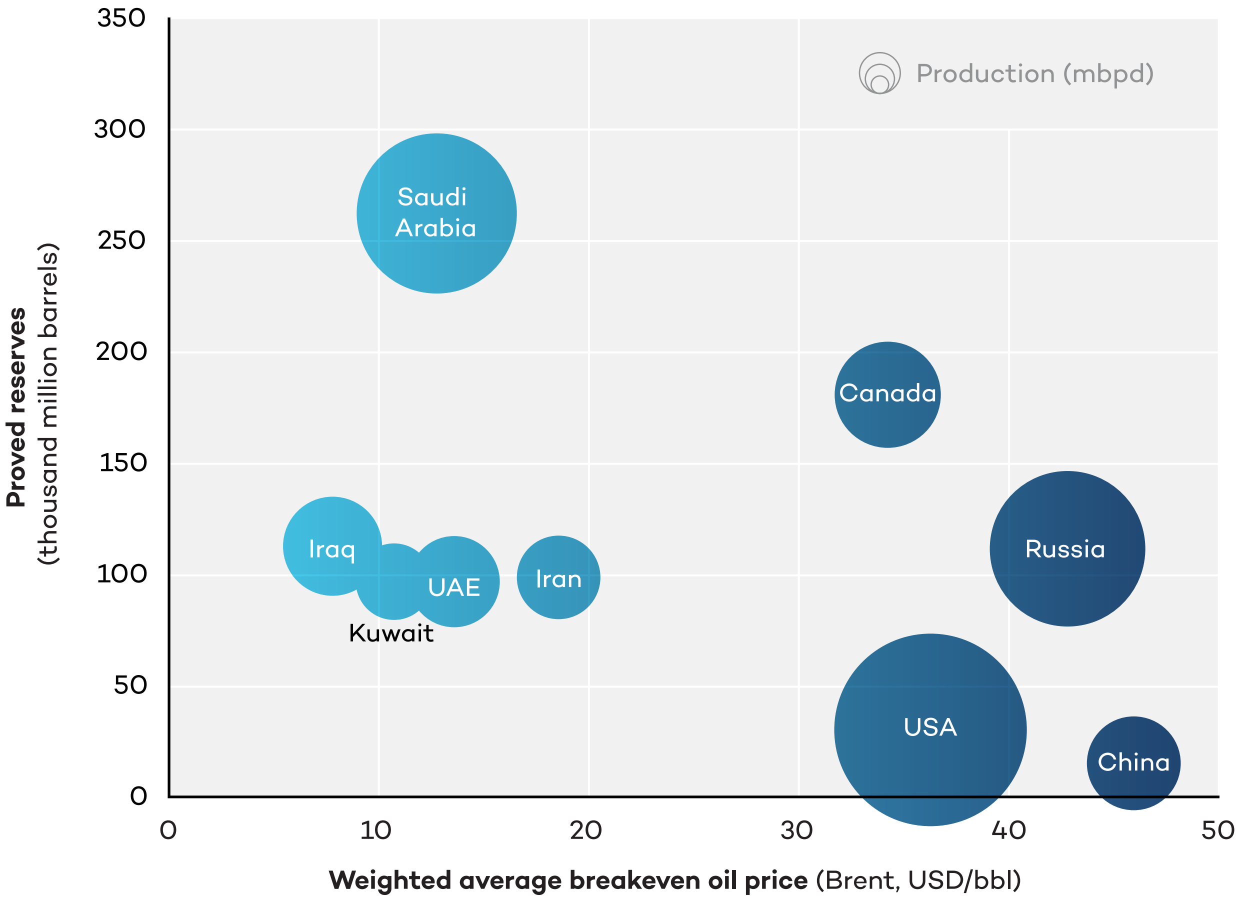
Canada Is Far From the Lowest-Cost Producer

If ESG status won't save Canadian oil's market share, could Canada compete on price? Most of Canada's crude oil exports do not compete directly on global markets, though there are increasing exports from the U.S. Gulf Coast that do, and there will be substantially more with the completion of the TMX pipeline. And Canadian crude does not compete directly with the lighter, sweeter crude produced in most other countries. But Canada's costs of production relative to its major competitors still matter in the long run, especially in a shrinking post-peak global market.

Figure 2 shows how those costs measure up among the top 10 oil-producing nations, expressed here as the weighted average Brent crude U.S. dollar per barrel breakeven price in each country.

While costs of production have come down dramatically in Canada over the last 20 years, Canada is still not a low-cost oil producer, especially compared to its Middle Eastern competitors.

Figure 2. Global costs and reserves



Note: Horizontal axis is the weighted average breakeven oil price for all existing producers. Bubble size indicates 2020 production levels.

Sources: Rystad UCube data; BP (2021).

As of November 2022, the price of Brent crude is in the mid-eighties (USD), so prices could fall significantly before most Canadian producers, with a weighted average breakeven oil price of USD 35.21, became unprofitable. But in a future global market with falling demand and prices, there would be significant reserves and production in countries that would continue to be profitable long after Canadian production is not.

The Post-Peak Market for Oil Will Be Savage

Despite Canada not currently participating directly in global markets, global supply and demand trends—and the prices that result from them—directly affect the price Canadian oil producers receive. It is, therefore, important to forecast the strategic behaviour of non-Canadian producers in response to what we know is coming: a peak of global demand by around 2030, followed by a marked decline (Cosbey, 2022).

In the face of lower returns driven by climate policy, some have predicted a dynamic known as the green paradox, where producers predict their reserves will be worth less in the future, and rush to extract and sell more of them in the present (Sinn, 2012). This would mean lower prices for all (and more consumption of cheap oil, hence the paradox). Others have criticized this theory, noting that significantly ramping up production is not a simple matter for most producers, particularly in the short term (Cairns, 2014).

In today's circumstances, however, the green paradox would not necessitate a difficult ramp-up—it could simply amount to deliberately following existing plans in the face of declining demand. A survey of production plans for 12 major oil-producing countries shows projected increases by 2030 amounting to more than 10% of 2020 global production (Stockholm Environment Institute et al., 2021). By contrast, under plausible assumptions, global demand for oil could decline 22% by 2030 and more steeply thereafter (Cosbey, 2022).

International (private) oil companies might change expansion plans in response to obvious decline trends; some shareholders would likely demand it. In the same vein, Cairns (2014) also criticizes the green paradox model on the grounds that it would be economically irrational for major producers to increase production and tank prices. But more than half of global oil supply comes from national oil companies (Natural Resource Governance Institute, 2019). These companies are not strictly profit motivated, and are usually mandated by national governments to contribute to broader policy objectives, such as creating employment (Losman, 2010). Some national governments will very likely demand a ramping-up of production in the face of declining demand and prices.

For decades, global oil markets have been protected from oversupply by the discipline of the Organization of the Petroleum Exporting Countries (OPEC) and, more recently, OPEC-plus. But the organization has always been subject to tensions, with heavily oil-dependent members seeking to increase production to address their urgent development needs (Blas et al., 2020; Lee, 2020; Smith et al., 2020). Declining oil prices with no long-term prospect for price recovery would ratchet those tensions up to new levels, risking a loss of collective discipline and resulting oversupply and volatility.

Conclusions

How will the coming peak and drop in global demand affect Canadian producers?

They will face low and volatile prices for oil. There is a mismatch between planned increases in production and potential decreases in consumption, which indicates prices will also go down. The weakening of OPEC discipline in a post-peak-oil world may also create increased price volatility, which has outsized impacts on investment, royalties, and other elements of the Alberta economy in particular (Cosbey et al., 2021).

And they will face declining demand for their products. Canada's focus on the United States as a destination market means it will be partly sheltered from global demand effects—U.S. refiners will buy Canadian crude even as global demand falls. But they will face increasing pressure as export markets are curtailed *and* domestic consumption falls. The refineries that buy Canada's oil are large, complex, and low cost and are likely to maintain markets for some time even as demand shrinks, but at some point, even they will curtail production.

Meanwhile, Canada cannot count on its producers' (often questionable) ESG credentials to preserve market share. While ESG matters to investors and to builders of pipelines seeking social licence, it does not matter to the refineries that buy Canada's oil; they are largely locked into Canadian heavy crude by massive investments in the capacity to use it as a feedstock.

Neither can Canada rely on a low cost of production to help its position. While Canadian producers have reduced costs significantly since 2014, their oil is, on average, still much more costly than that of all the major Middle Eastern producers, which have huge reserves and capacity. In a battle to sell the last barrel, we face a cost disadvantage.

All things considered, it is straightforward to predict whether Canada will sell the last barrel of oil; it will not. But the more immediate and fundamental question is this: how will Canada fare in the savage post-2030 market of declining demand—a market characterized by low prices and even more volatility than the historical norm? Canada's marginal producers will not survive; its more efficient producers will reap low profits, remitting low royalties and taxes. New investments will be almost unthinkable, other than incremental extensions of existing operations. Based on past experience, between cost-cutting and lack of new investment, the sector will shed large numbers of workers.

The coming peak and drop in global demand matters for Canadian producers—in the long run, it presents an existential threat. In the near-to-medium term it promises to take the vitality out of a sector that has historically contributed enormously to the Canadian and provincial economies.

These realities are acutely important for Canadian government policy. Canada cannot afford to delay support for diversifying into sectors that can replace oil as an engine of economic prosperity while simultaneously building a cleaner, healthier world.

References

Alberta Environmental Monitoring Panel. (2011). *A world class environmental monitoring, evaluation and reporting system for Alberta: The report of the Alberta Environmental Monitoring Panel*. https://wbea.org/wp-content/uploads/2018/06/a_world_class_environmental_monitoring_evaluation_and_reporting_system_for_alberta_the_report_of_the_alberta_environmental_monitoring_panel.pdf

Baker, J. M., & Westman, C. N. (2018). Extracting knowledge: Social science, environmental impact assessment, and Indigenous consultation in the oil sands of Alberta, Canada. *The Extractive Industries and Society, 5*(1), 144–153. https://harvest.usask.ca/handle/10388/12503

Beaver Lake Cree Nation. (n.d.). *Defend the treaties. Draw the line*. https://beaverlakecreenation.ca/defend-the-treaties/

Birn, K., & Crawford, C. (2020). *The GHG intensity of Canadian oil: A new analysis*. IHS Markit.

Blas, J., Smith, G., & El Wardany, S. (2020, April 9). *Global oil deal at risk after Mexico refuses Saudi-Russia plan*. Bloomberg Markets. https://www.bloomberg.com/news/articles/2020-04-09/opec-agrees-on-deep-oil-output-cuts-to-fight-market-slump

Boychuk, R., Anielski, M., Snow, J., Jr., & Stelfox, B. (2021). *The big cleanup: How enforcing the polluter pay principle can unlock Alberta's next great jobs boom*. Alberta Liabilities Disclosure Project. https://www.aldpcoalition.com/_files/ugd/6ca287_2ffe90ca7c354d3eac43b5f141b6ec8a.pdf

BP. (2022). *Energy outlook 2022*. https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2022.pdf

Braid, D. (2022, February 10). Braid: In public shift, Kenney says Alberta has to go green over time. *Calgary Herald*. https://calgaryherald.com/news/politics/braid-in-public-shift-kenney-says-alberta-has-to-go-green-over-time

Cairns, R. D. (2014). The green paradox of the economics of exhaustible resources. *Energy Policy, 65*, 78–85.

Canada Energy Regulator. (2021). *Canada's energy future 2021*. https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/index.html

Canada Energy Regulator. (2022). *Commodity statistics*. https://apps.cer-rec.gc.ca/CommodityStatistics/Statistics.aspx?language=englishhttps://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx?language=english

Canadian Association of Petroleum Producers. (n.d.). *Climate change & the Canadian oil and gas industry*. https://www.capp.ca/environment/climate-change/

Cosbey, A. (2022). *Why Canada needs to plan for a steep decline in global oil demand*. International Institute for Sustainable Development. https://www.iisd.org/articles/deep-dive/canada-can-expect-declining-oil-demand

Cosbey, A., Sawyer, D., & Stiebert, S. (2021). *In search of prosperity: The role of oil in the future of Alberta and Canada*. International Institute for Sustainable Development. https://www.iisd.org/publications/search-prosperity-oil-alberta-canada

CSRHub. (n.d.). *Oil & gas sustainability ratings*. CSRHub Consensus ESG Ratings. https://www.csrhub.com/search/industry/Oil-and-Gas-Extraction

De Souza, M., Jarvis, C., McIntosh, E., & Bruser, D. (2018, November 1). *Alberta regulator privately estimates oilpatch's financial liabilities are hundreds of billions more than what it told the public*. Canada's National Observer. https://www.nationalobserver.com/2018/11/01/news/alberta-regulator-privately-estimates-oilpatchs-financial-liabilities-are-hundreds

DNV. (2022). *Energy transition outlook 2022: A global and regional forecast to 2050*. https://www.dnv.com/energy-transition-outlook/index.html

Dziuba, J., Ollenberger, R., Kwan, R., & Wittkopf, C. (2020). *The 400 billion barrel opportunity for friendly oil, and Canada's evolving role*. BMO Capital Markets. https://research-ca.bmocapitalmarkets.com/documents/140A6529-CE63-4B90-A627-06768A001783.PDF

Flavelle, C. (2020, February 12). Global financial giants swear off funding an especially dirty fuel. *The New York Times*. https://www.nytimes.com/2020/02/12/climate/blackrock-oil-sands-alberta-financing.html

French, J. (2022, March 8). *Oil and gas companies now owe Alberta rural communities $253M in unpaid taxes*. CBC. https://www.cbc.ca/news/canada/edmonton/oil-and-gas-companies-now-owe-alberta-rural-communities-253m-in-unpaid-taxes-1.6377641

Gearino, D. (2022, September 1). *California just banned gas-powered cars. Here's everything you need to know*. Inside Climate News. https://insideclimatenews.org/news/01092022/california-just-banned-gas-powered-cars-heres-everything-you-need-to-know/

Government of Canada. (2020, April 17). *Prime Minister announces new support to protect Canadian jobs*. Prime Minister of Canada. https://pm.gc.ca/en/news/news-releases/2020/04/17/prime-minister-announces-new-support-protect-canadian-jobs

Graney, E. (2021, March 1). ESG focus will help attract investors to oil sands, Kenney says. *The Globe and Mail*. https://www.theglobeandmail.com/business/article-how-alberta-will-implement-esg-measures/

Healing, D. (2020, July 30). *Total "virtue signalling" by writing off oil sands assets: CAPP CEO*. BNN Bloomberg. https://www.bnnbloomberg.ca/total-takes-8-billion-writedown-on-carbon-heavy-oil-assets-1.1472601

House Select Committee on the Climate Crisis. (2020). *Solving the climate crisis: The congressional action plan for a clean energy economy and a healthy, resilient, and just America*. House Select Committee on the Climate Crisis. https://climatecrisis.house.gov/sites/climatecrisis.house.gov/files/Climate%20Crisis%20Action%20Plan.pdf

International Energy Agency. (2022). *World energy outlook 2022*. https://www.iea.org/reports/world-energy-outlook-2022

Jenkins, J. D., Mayfield, E., Farbes, J., Jones, R., Patankar, N., Xu, Q., & Schivley, G. (2022). *Preliminary report: The climate and energy impacts of the Inflation Reduction Act of 2022*. Zero-carbon Energy Systems Research and Optimization Laboratory. https://repeatproject.org/docs/REPEAT_IRA_Prelminary_Report_2022-08-12.pdf

Kelly, S., & Williams, N. (2022, February 11). *Canadian oil barrels head out of the U.S. Gulf in record numbers*. Reuters. https://www.reuters.com/business/energy/canadian-oil-barrels-head-out-us-gulf-record-numbers-2022-02-11/

Leahy, S. (2019). *This is the world's most destructive oil operation—And it's growing. National Geographic*. https://www.nationalgeographic.com/environment/article/alberta-canadas-tar-sands-is-growing-but-indigenous-people-fight-back

Lee, J. (2020, September 12). *There's no easy fix to OPEC's whack-a-mole problem.* Bloomberg.com. https://www.bloomberg.com/opinion/articles/2020-09-13/opec-s-60th-birthday-the-oil-cartel-s-got-a-whack-a-mole-problem

Lewis, J., Jones, J., D'Aliesio, R., Wang, C. (2018, November 23). Hustle in the oil patch: Inside a looming financial and environmental crisis. *The Globe and Mail.* https://www.theglobeandmail.com/canada/article-hustle-in-the-oil-patch-inside-a-looming-financial-and-environmental/

Liggio, J., Li, S.-M., Hayden, K., Taha, Y. M., Stroud, C., Darlington, A., Drollette, B. D., Gordon, M., Lee, P., Liu, P., Leithead, A., Moussa, S. G., Wang, D., O'Brien, J., Mittermeier, R. L., Brook, J. R., Lu, G., Staebler, R. M., Han, Y., … Gentner, D. R. (2016). Oil sands operations as a large source of secondary organic aerosols. *Nature*, *534*, Article 7605. https://doi.org/10.1038/nature17646

Losman, D. L. (2010). The rentier state and national oil companies: An economic and political perspective. *Middle East Journal, 64*(3), 427–445. https://doi.org/10.3751/64.3.15

Lower Athabasca Regional Plan Review Panel. (2015). *Review panel report 2015: Lower Athabasca Regional Plan.* https://open.alberta.ca/dataset/5c910acf-9e8c-46b5-b52d-60fc8bd2bbbd/resource/d9a6bff5-f9b5-45fe-81ed-a8de3492e271/download/2016-review-panel-report-2015-lower-athabasca-regional-plan-2016-06-22.pdf

Masnadi, M. S., El-Houjeiri, H. M., Schunack, D., Li, Y., Englander, J. G., Badahdah, A., Monfort, J.-C., Anderson, J. E., Wallington, T. J., Bergerson, J. A., Gordon, D., Koomey, J., Przesmitzki, S., Azevedo, I. L., Bi, X. T., Duffy, J. E., Heath, G. A., Keoleian, G. A., McGlade, C., … Brandt, A. R. (2018). Global carbon intensity of crude oil production. *Science, 361*(6405), 851–853. https://doi.org/10.1126/science.aar6859

McKinsey. (2022). *Global energy perspective 2022.* https://www.mckinsey.com/~/media/McKinsey/Industries/Oil%20and%20Gas/Our%20Insights/Global%20Energy%20Perspective%202022/Global-Energy-Perspective-2022-Executive-Summary.pdf

Natural Resource Governance Institute. (2019, April 18). *The national oil company database*. https://resourcegovernance.org/analysis-tools/publications/national-oil-company-database

Orphan Well Association. (2022a). *Orphan inventory*. https://www.orphanwell.ca/about/orphan-inventory/

Orphan Well Association. (2022b). *Orphan Well Association annual report 2021/2022*. https://www.orphanwell.ca/wp-content/uploads/2022/07/OWA-Annual_2021_web.pdf

Riley, S. J. (2022, April 5). The Alberta government spent another $22 million on unpaid land rent for oil and gas operators in 2021. *The Narwhal*. https://thenarwhal.ca/alberta-oil-gas-land-rent-2021/

Rystad Energy. (2022). *Upstream trends report June 2022*.

Senate Democrats Special Committee on the Climate Crisis. (2020). *The case for climate action: Building a clean economy for the American people*. https://www.schatz.senate.gov/imo/media/doc/SCCC_Climate_Crisis_Report.pdf

Sinn, H.-W. (2012). *The green paradox*. MIT Press.

Sleep, S., Dadashi, Z., Chen, Y., Brandt, A. R., MacLean, H., & Bergerson, J. A. (2021). Improving robustness of LCA results through stakeholder engagement: A case study of emerging oil sands technologies. *Journal of Cleaner Production, 281*. https://doi.org/10.1016/j.jclepro.2020.125277

Smith, G., Blas, J., & El Wardany, S. (2020, December 1). *OPEC+ works silently to repair crack at oil coalition's core*. Bloomberg. https://www.bloomberg.com/news/articles/2020-12-01/opec-splits-at-its-core-risking-deal-that-underpins-oil-price

Stockholm Environment Institute, International Institute for Sustainable Development, ODI, E3G, & United Nations Environment Programme. (2021). *The production gap report 2021*. https://productiongap.org/wp-content/uploads/2021/11/PGR2021_web_rev.pdf

Tuncak, B. (2020). *Visit to Canada: Report of the Special Rapporteur on the implications for human rights of the environmentally sound management and disposal of hazardous substances and wastes (A/HRC/45/12/Add.1)*. UN Human Rights Council. http://www.srtoxics.org/wp-content/uploads/2020/09/Canada-HRC-45_AUV.pdf

UN Comtrade. (2021). *International trade statistics database*. https://comtrade.un.org/

United States Energy Information Agency. (n.d.). *Oil imports and exports*. https://www.eia.gov/energyexplained/oil-and-petroleum-products/imports-and-exports.php

Voora, V., Larrea, C., Huppé, G., & Nugnes, F. (2022). *Standards and investments in sustainable agriculture*. IISD's State of Sustainability Initiatives Review Series. International Institute for Sustainable Development. https://www.iisd.org/system/files/2022-04/ssi-initiatives-review-standards-investments-agriculture.pdf

RE-ENERGIZING CANADA

Re-Energizing Canada is a multi-year IISD research project envisioning Canada's future beyond oil and gas. This publication is part one of *The Bottom Line* policy brief series, which digs into the complex questions that will shape Canada's place in future energy markets.

INTERNATIONAL INSTITUTE FOR SUSTAINABLE DEVELOPMENT

The International Institute for Sustainable Development (IISD) is an award-winning independent think tank working to accelerate solutions for a stable climate, sustainable resource management, and fair economies. Our work inspires better decisions and sparks meaningful action to help people and the planet thrive. We shine a light on what can be achieved when governments, businesses, non-profits, and communities come together. IISD's staff of more than 120 people, plus over 150 associates and consultants, come from across the globe and from many disciplines. With offices in Winnipeg, Geneva, Ottawa, and Toronto, our work affects lives in nearly 100 countries.

IISD is a registered charitable organization in Canada and has 501(c)(3) status in the United States. IISD receives core operating support from the Province of Manitoba and project funding from governments inside and outside Canada, United Nations agencies, foundations, the private sector, and individuals.

Head Office

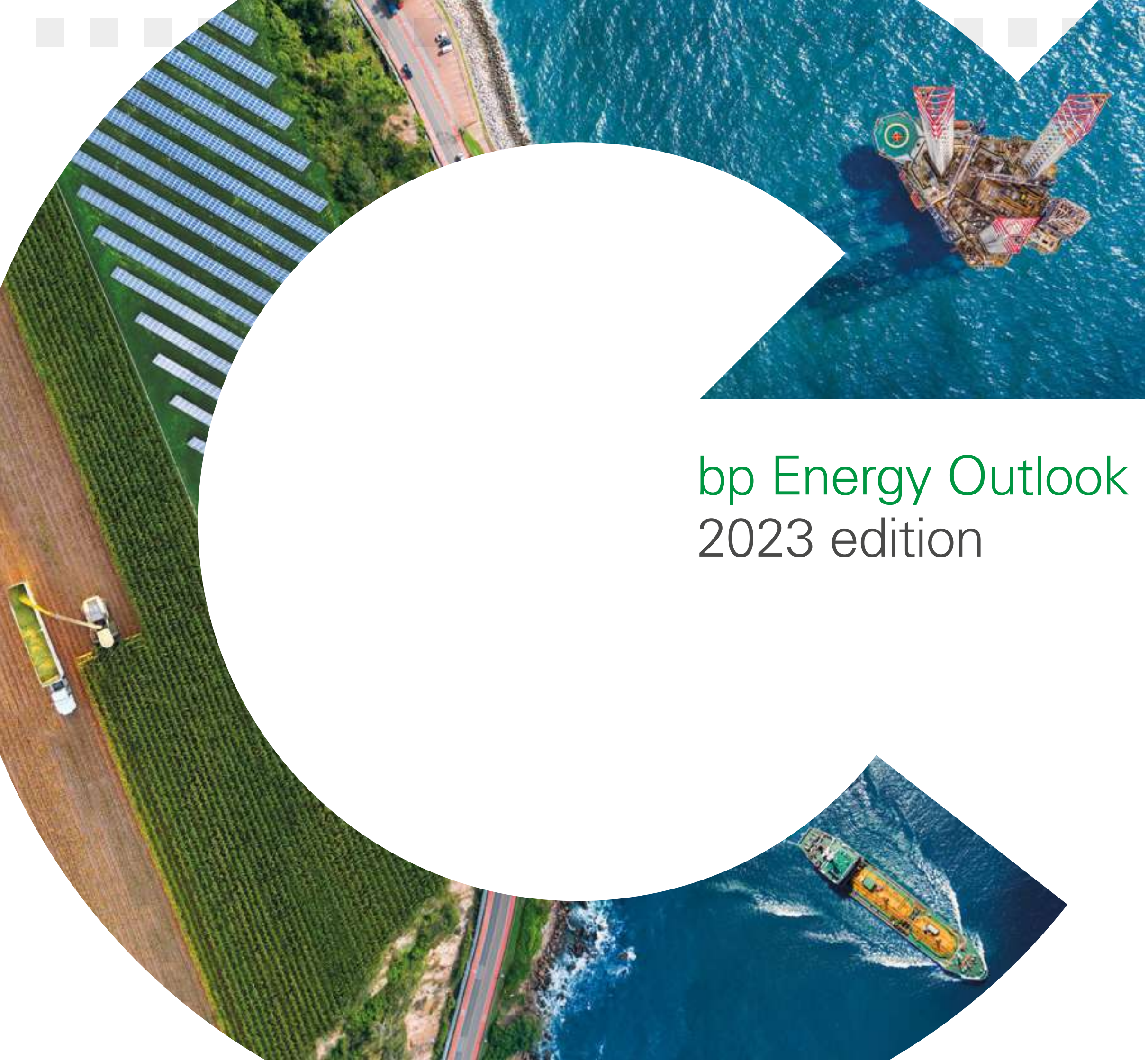
111 Lombard Avenue, Suite 325
Winnipeg, Manitoba
Canada R3B 0T4

Tel: +1 (204) 958-7700
Website: www.iisd.org
Twitter: @IISD_news

IISD

iisd.org

EXHIBIT F



bp

bp Energy Outlook
2023 edition

Updated July 2023

Energy Outlook 2023 explores the key trends and uncertainties surrounding the energy transition.

Energy Outlook 2023 is focused on three main scenarios: *Accelerated*, *Net Zero* and *New Momentum*. These scenarios are not predictions of what is likely to happen or what bp would like to happen. Rather they explore the possible implications of different judgements and assumptions concerning the nature of the energy transition and the uncertainties around those judgements. The scenarios are based on existing technologies and do not consider the possible impact of entirely new or unknown technologies.

The many uncertainties surrounding the transition of the global energy system mean that the probability of any one of these scenarios materializing exactly as described is negligible. Moreover, the three scenarios do not provide a comprehensive range of possible paths for the transition ahead. They do, however, span a wide range of possible outcomes and so help to illustrate the key uncertainties surrounding energy markets out to 2050.

The scenarios in this year's *Outlook* have been updated to take account of two major developments over the past year: the Russia-Ukraine war and the passing of the Inflation Reduction Act in the US. Aside from updating for those two developments, the scenarios are based largely on the analysis and scenarios in *Energy Outlook 2022*. They do not include a comprehensive assessment of all the changes and developments since *Outlook 2022*.

The *Outlook*, that was published in January, uses the scenarios discussed for different fuels and energy sources, such as oil, natural gas, renewables and low-carbon hydrogen. An additional chapter, published in July, contains further analysis that uses the same three scenarios to discuss the outlook for end-use energy demand, in particular in the industry, buildings and transport sectors.

The *Energy Outlook* is produced to inform bp's strategy and is published as a contribution to the wider debate about the factors shaping the energy transition. But the *Outlook* is only one source among many when considering the future of global energy markets and bp considers a wide range of other external scenarios, analysis and information when forming its long-term strategy.

Welcome to the 2023 edition of bp's *Energy Outlook*.

The past year has been dominated by the terrible consequences of the Russia-Ukraine war and its awful toll on lives and communities. Our thoughts and hopes are with all those affected.

From an energy perspective, the disruptions to Russian energy supplies and the resulting global energy shortages seem likely to have a material and lasting impact on the energy system.

Global energy policies and discussions in recent years have been focused on the importance of decarbonizing the energy system and the transition to net zero. The events of the past year have served as a reminder to us all that this transition also needs to take account of the security and affordability of energy. Together these three dimensions of the energy system – security, affordability, and sustainability – make up the energy trilemma. Any successful and enduring energy transition needs to address all three elements of the trilemma.

Last year's *Energy Outlook* did not include any analysis of the possible implications of the war in Ukraine. The scenarios in *Outlook 2023* have been updated to take account of the war, as well as of the passing of the Inflation Reduction Act in the US.

At the time of writing, the war is continuing with no end in sight. As such, any analysis of its possible implications must be treated as preliminary. However, the experience from the major energy supply shocks of the 1970s suggests that events that heightened energy security concerns can have significant and persistent impacts on energy markets.

Most importantly, the desire of countries to bolster their energy security by reducing their dependency on imported energy – dominated by fossil fuels – and instead have access to more domestically produced energy – much of which is likely to come from renewables and other non-fossil energy sources – suggests that the war is likely to accelerate the pace of the energy transition.

The scale of the economic and social disruptions over the past year associated with the loss of just a fraction of the world's fossil fuels has also highlighted the need for the transition away from hydrocarbons to be orderly, such that the demand for hydrocarbons falls in line with available supplies, avoiding future periods of energy shortages and higher prices.

These issues, together with the broader implications of the energy transition, are explored in this year's *Energy Outlook* using three main scenarios: *Accelerated*, *Net Zero* and *New Momentum*. Together these scenarios span a wide range of the possible outcomes for the global energy system over the next 30 years. Understanding this range of uncertainty helps bp to shape a strategy which is resilient to the different speeds and ways in which the energy system may transition.

The continuing rise in carbon emissions and the increasing frequency of extreme weather events in recent years highlight more clearly than ever the importance of a decisive shift towards a net-zero future. The events of the past year have highlighted the complexity and interconnectedness of the global energy system and the need to address all three dimensions of the energy trilemma. I hope this year's *Energy Outlook* is useful to everyone trying to navigate this uncertain future and accelerate the transition to global net zero.

As always, any feedback on the *Outlook* and how it can be improved would be most welcome.

Spencer Dale

Spencer Dale
Chief economist

Core Beliefs

This year's *Outlook* can be used to identify aspects of the energy transition that are common across the main scenarios. These trends help shape core beliefs about how the energy system may evolve over the next 30 years.

- The carbon budget is running out. Despite the marked increase in government ambitions, CO_2 emissions have increased every year since the Paris COP in 2015 (bar 2020). The longer the delay in taking decisive action to reduce emissions on a sustained basis, the greater are the likely resulting economic and social costs.
- Government support for the energy transition has increased in a number of countries, including the passing of the Inflation Reduction Act in the US. But the scale of the decarbonization challenge suggests greater support is required globally, including policies to facilitate quicker permitting and approval of low-carbon energy and infrastructure.
- The disruption to global energy supplies and associated energy shortages caused by the Russia-Ukraine war increases the importance attached to addressing all three elements of the energy trilemma: security, affordability, and sustainability.
- The war has long-lasting effects on the global energy system. The heightened focus on energy security increases demand for domestically produced renewables and other non-fossil fuels, helping to accelerate the energy transition.
- The structure of energy demand changes, with the importance of fossil fuels declining, replaced by a growing share of renewable energy and by increasing electrification. The transition to a low-carbon world requires a range of other energy sources and technologies, including low-carbon hydrogen, modern bioenergy, and carbon capture, use and storage.
- Oil demand declines over the outlook, driven by falling use in road transport as the efficiency of the vehicle fleet improves and the electrification of road vehicles accelerates. Even so, oil continues to play a major role in the global energy system for the next 15-20 years.

- The prospects for natural gas depend on the speed of the energy transition, with increasing demand in emerging economies as they grow and industrialize offset by the transition to lower carbon energy sources, led by the developed world.
- The recent energy shortages and price spikes highlight the importance of the transition away from hydrocarbons being orderly, such that the demand for hydrocarbons falls in line with available supplies. Natural declines in existing production sources mean there needs to be continuing upstream investment in oil and natural gas over the next 30 years.
- The global power system decarbonizes, led by the increasing dominance of wind and solar power. Wind and solar account for all or most of the growth in power generation, aided by continuing cost competitiveness and an increasing ability to integrate high proportions of these variable power sources into power systems. The growth in wind and solar requires a significant acceleration in the financing and building of new capacity.
- The use of modern bioenergy – modern solid biomass, biofuels and biomethane – grows rapidly, helping to decarbonize hard-to-abate sectors and processes.
- Low-carbon hydrogen plays a critical role in decarbonizing the energy system, especially in hard-to-abate processes and activities in industry and transport. Low-carbon hydrogen is dominated by green and blue hydrogen, with green hydrogen growing in importance over time. Hydrogen trade is a mix of regional pipelines transporting pure hydrogen and global seaborne trade in hydrogen derivatives.
- Carbon capture, use and storage plays a central role in enabling rapid decarbonization trajectories: capturing industrial process emissions, acting as a source of carbon dioxide removal, and abating emissions from the use of fossil fuels.
- A range of methods for carbon dioxide removal – including bioenergy combined with carbon capture and storage, natural climate solutions, and direct air carbon capture with storage – will be needed for the world to achieve a deep and rapid decarbonization.

Contents

Overview

Three scenarios to explore the uncertainties surrounding the speed and shape of the energy transition to 2050

Accelerated and *Net Zero* are broadly in line with 'Paris consistent' IPCC scenarios

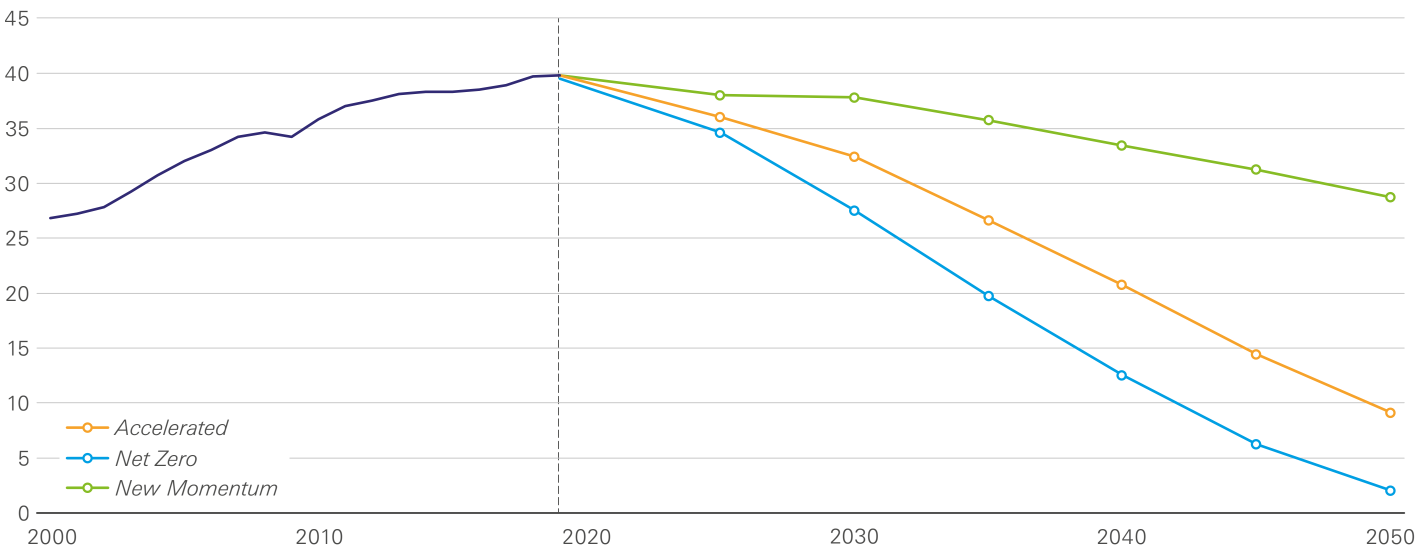
Final energy demand peaks in all three scenarios as gains in energy efficiency accelerate

The future of global energy is dominated by four trends: declining role for hydrocarbons, rapid expansion in renewables, increasing electrification, and growing use of low-carbon hydrogen

Three scenarios to explore the uncertainties surrounding the speed and shape of the energy transition to 2050

Carbon emissions

Gt of CO_2e



Carbon emissions include CO_2 emissions from energy use, industrial processes, natural gas flaring, and methane emissions from energy production.

Key points

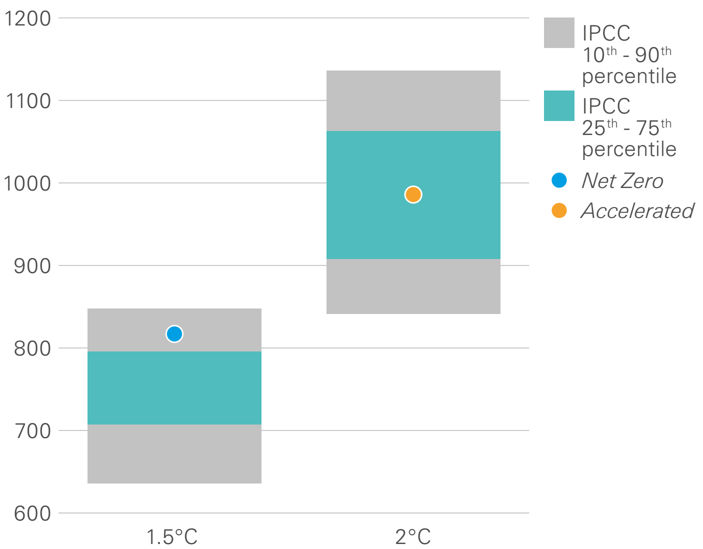
bp's *Energy Outlook 2023* uses three scenarios (*Accelerated*, *Net Zero* and *New Momentum*) to consider a range of possible pathways for the global energy system to 2050 and to help shape a resilient strategy for bp.

- The scenarios are not predictions of what is likely to happen or what bp would like to happen. Rather, the scenarios are designed to span a wide range of the outcomes possible out to 2050. In doing so, they inform bp's core beliefs about the energy transition and help shape a strategy that is resilient to the many uncertainties surrounding the speed and nature of the energy transition.
- The scenarios in this year's *Outlook* have been updated to take account of two major developments over the past year: the Russia-Ukraine war and the passing of the Inflation Reduction Act in the US. Aside from updating for those two developments, the scenarios are largely based on the analysis and scenarios in *Energy Outlook 2022*.
- The scenarios consider carbon emissions from energy production and use, most non-energy related industrial processes, and natural gas flaring plus methane emissions from the production, transmission, and distribution of fossil fuels (see pages 122-123 of the Annex for more details).
- *Accelerated* and *Net Zero* explore how different elements of the energy system might change in order to achieve a substantial reduction in carbon emissions. In that sense, they can be viewed as 'what if' scenarios: what elements of the energy system might need to change if the world collectively takes action for CO_2-equivalent emissions (CO_2e) to fall by around 75% by 2050 (relative to 2019 levels) in *Accelerated* and 95% in *Net Zero*. Both scenarios are conditioned on the assumption that there is a significant tightening in climate policies. *Net Zero* also embodies a shift in societal behaviour and preferences, which further supports gains in energy efficiency and the adoption of low-carbon energy.
- The carbon emissions remaining in *Net Zero* in 2050 could be eliminated by either additional changes to the energy system or by the deployment of carbon dioxide removal (CDR) (see pages 78-79). This will depend on the costs of CDR and of abating greenhouse gasses emanating from outside the energy system, neither of which are explicitly considered in the *Outlook*.
- *New Momentum* is designed to capture the broad trajectory along which the global energy system is currently travelling. It places weight on the marked increase in global ambition for decarbonization in recent years, as well as on the manner and speed of decarbonization seen over the recent past. CO_2e emissions in *New Momentum* peak in the 2020s and by 2050 are around 30% below 2019 levels.

Accelerated and *Net Zero* are broadly in line with 'Paris consistent' IPCC scenarios

Cumulative CO_2e emissions from energy (2015 - 2050)

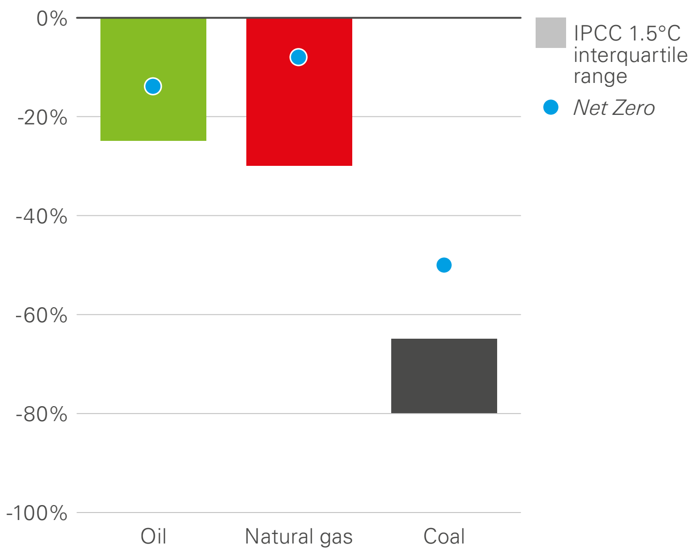
Gt of CO_2e



Cumulative CO_2e emissions in 2015-2050 are the addition of CO_2 emissions from energy and industrial processes, flaring, and methane emissions

Change in fossil fuels in IPCC 1.5°C scenarios

2019-2030 change



1.5°C scenarios with no or limited overshoot and 2°C scenarios with immediate action. See Annex for selection of IPCC scenarios

Key points

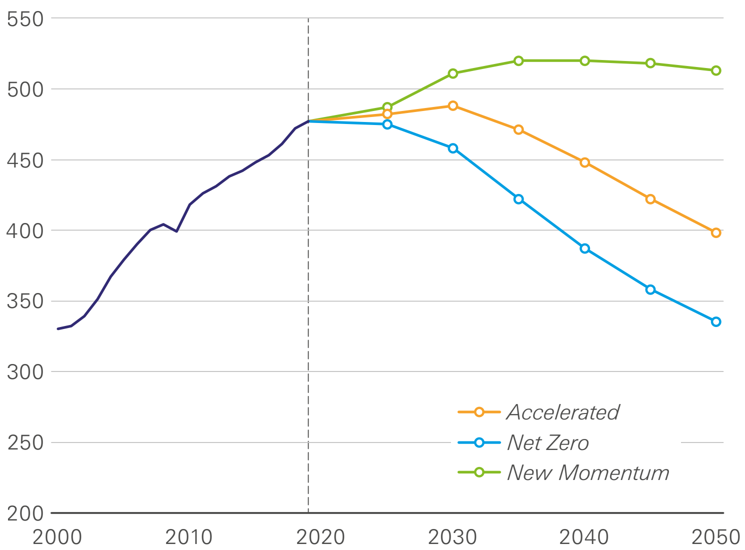
The pace and extent of decarbonization in *Accelerated* and *Net Zero* are broadly aligned with a range of IPCC scenarios which are consistent with maintaining global average temperature rises well below 2°C and 1.5°C above pre-industrial levels in 2100 respectively (see annex pages 122-123 for more details of IPCC scenarios used).

- The *Energy Outlook* scenarios extend only to 2050 and do not model all forms of greenhouse gasses or all sectors of the economy. As such, it is not possible to map directly between the scenarios and their implications for the carbon budget and the implied increase in average global temperatures by 2100.
- However, it is possible to provide an indirect inference by comparing the cumulative carbon emissions in *Accelerated* and *Net Zero* for the energy sector over the period 2015 to 2050 with the ranges of corresponding carbon trajectories taken from the scenarios included in the IPCC Sixth Assessment Report – Climate Change 2022: Impacts, Adaptation and Vulnerability.
- Cumulative CO_2e emissions in *Accelerated* are broadly in the middle of the interquartile range of well below 2°C IPCC scenarios. The trajectory for carbon emissions in *Accelerated* lies within the IPCC range over the entire outlook.
- For *Net Zero*, cumulative CO_2e emissions are within the 10^{th} to 90^{th} percentiles of IPCC scenarios consistent with 1.5°C (with no or limited overshoot), but are a little above the interquartile range. Carbon emissions in *Net Zero* decline more slowly than the range of IPCC 1.5°C scenarios out to 2030, before falling more quickly than the median scenario further out.
- In the median IPCC scenario consistent with 1.5°C (with no or limited overshoot), net CO_2 emissions decline by 48% by 2030 (relative to 2019 levels). Within this, CO_2 emissions from 'fossil fuels and industrial processes' fall by 40%. This compares with a fall of 30% in *Net Zero*.
- The fall in fossil fuels and industrial emissions in the median IPCC scenario is driven largely by a 75% fall in global coal consumption by 2030, with more modest falls of around 10% in oil and natural gas consumption. The falls in oil and natural gas by 2030 in *Net Zero* are consistent with the range of IPCC 1.5°C scenarios, but the fall in coal consumption is significantly smaller. That reflects the continuing importance of coal as an affordable and relatively abundant fuel in many emerging economies where energy demand is expanding rapidly.
- The time it takes for parts of the energy sector to transition away from fossil fuels highlights the likely importance of carbon dioxide removal (CDR) in helping to reduce net carbon emissions during the transition period while these reforms are undertaken, as well as offsetting any remaining gross emissions in a net zero energy system (see pages 78-79).

Final energy demand peaks in all three scenarios as gains in energy efficiency accelerate

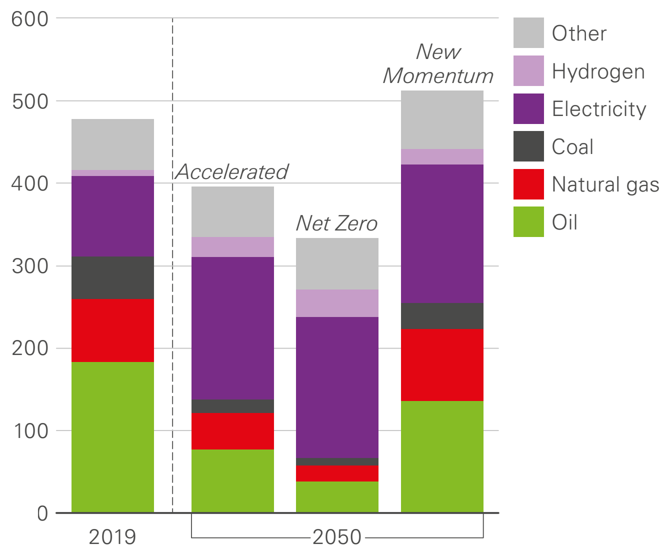
Total final consumption

EJ



Total final consumption by fuel

EJ



Key points

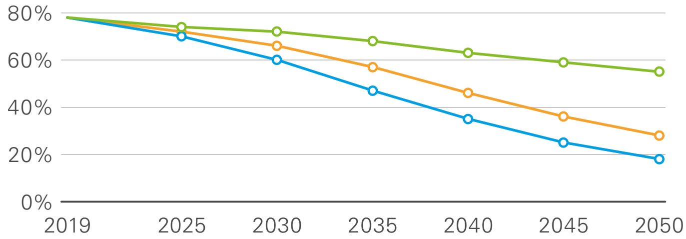
Global energy demand measured at the final point of use (total final consumption) peaks in all three scenarios as gains in energy efficiency accelerate, more than offsetting the upwards impact of increasing living standards across much of the emerging world.

- Total final consumption (TFC) peaks in the mid-to-late 2020s in *Accelerated* and *Net Zero*, with final energy consumption 15-30% below 2019 levels by 2050. In contrast, TFC increases until around 2040 in *New Momentum*, after which it broadly plateaus with energy consumption in 2050 around 10% above 2019 levels.
- The main factor driving these differences in final energy consumption is the pace of improvement in energy efficiency. The gains in global energy efficiency over the outlook – measured by comparing growth in final energy demand with economic activity – are much quicker than over the past 20 years in all three scenarios, particularly in *Accelerated* and *Net Zero*. That reflects a number of factors including: the increasing use of electricity at the final point of use, more efficient use of materials through increased recycling and reuse, and a greater focus on energy conservation, given greater impetus by the heightened focus on energy security (see pages 22-23).
- The assumed increase in the pace of energy efficiency improvements in *Accelerated* and *Net Zero* is a central element in facilitating a rapid reduction in carbon emissions, without which there would need to be even faster growth in low-carbon energy to achieve the same outcome.
- Final energy demand in emerging markets continues to grow over the coming decade and beyond in *New Momentum* and *Accelerated*, driven by increasing prosperity and improving living standards. In contrast, demand in developed economies peaks in the next few years in all three scenarios.
- Total final consumption decarbonizes as the direct use of fossil fuels declines, the world electrifies and the power sector is increasingly decarbonized.
- Within TFC, fossil fuels used at the final point of energy use decline from a share of around 65% in 2019 to 20-50% by 2050 across the three scenarios. Within hydrocarbons, the share of coal falls particularly sharply as the world increasingly shifts to the use of electricity and low-carbon hydrogen in industry, as does the share of oil, driven primarily by the falling use of oil in road transport (see pages 42-43).
- The role of electricity increases substantially and broadly uniformly across all three scenarios, with electricity consumption increasing by around 75% by 2050.

The future of global energy is dominated by four trends: declining role for hydrocarbons, rapid expansion in renewables, increasing electrification, and growing use of low-carbon hydrogen

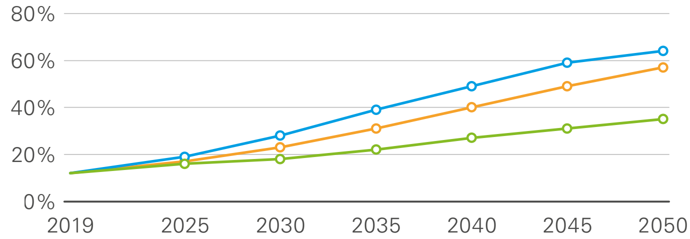
Fossil fuels

Share of primary energy



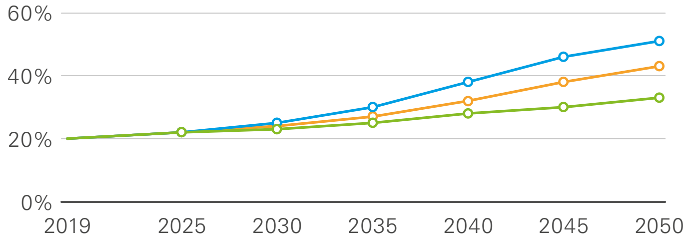
Renewables

Share of primary energy



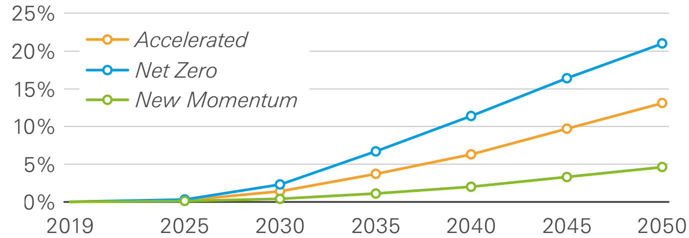
Electricity

Share of total final consumption



Low-carbon hydrogen

Share of primary energy used in production of hydrogen



Key points

The changing composition of energy demand over the outlook is characterized by four trends: a gradual decline in the role of hydrocarbons, rapid growth in renewable energy, and an increasing electrification of the world, supported by low-carbon hydrogen in processes and activities which are hard to electrify.

- The role of hydrocarbons diminishes as the world transitions to lower carbon energy sources. The share of fossil fuels in primary energy declines from around 80% in 2019 to between 55-20% by 2050.
- The total consumption of fossil fuels declines in all three scenarios over the outlook. This would be the first time in modern history that there has been a sustained fall in the demand for any fossil fuel.
- Renewable energy is largely made up of wind and solar power and bioenergy, and also includes geothermal power. Renewables expand rapidly over the outlook, offsetting the declining role of fossil fuels. The share of renewables in global primary energy increases from around 10% in 2019 to between 35-65% by 2050, driven by the improved cost competitiveness of renewables, together with the increasing prevalence of policies encouraging a shift to low-carbon energy.
- In all three scenarios, the pace at which renewable energy penetrates the global energy system is quicker than any previous fuel in history.
- The growing importance of renewable energy is underpinned by the continuing electrification of the energy system. The share of electricity in total final energy consumption increases from around a fifth in 2019 to between a third and a half by 2050.
- The decarbonization of the energy system, especially in *Accelerated* and *Net Zero*, is supported by the growing use of low-carbon hydrogen in hard-to-abate processes which are difficult or costly to electrify. The share of primary energy used in the production of low-carbon hydrogen increases to between 13-21% by 2050 in *Accelerated* and *Net Zero*.

Changes since *Energy Outlook 2022*

The Russia-Ukraine war is likely to have long-lasting effects on the global energy system

The Russia-Ukraine war leads to a downward revision in the outlook for global GDP and energy demand

Increased energy security concerns trigger a shift towards a more local, lower-carbon energy mix

Energy security concerns reduce the role of oil and natural gas imports

The Russia-Ukraine war and the Inflation Reduction Act lower the outlook for carbon emissions

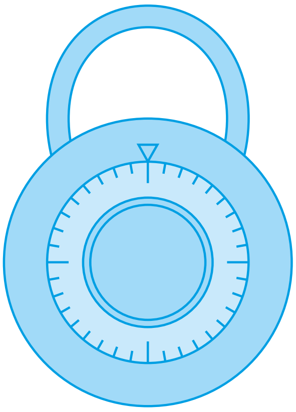
Russian production of oil and natural gas revised down as a result of the war

EU's need for LNG imports in 2030 depends on its success in reducing natural gas demand

The Inflation Reduction Act provides significant support for low-carbon energy and technologies in the US

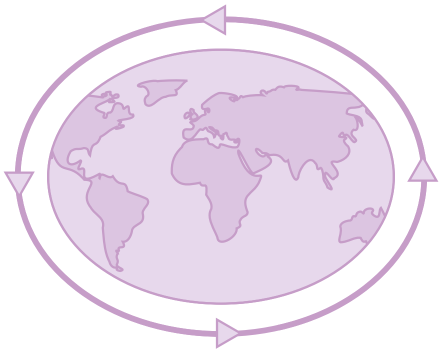
The Russia-Ukraine war is likely to have long-lasting effects on the global energy system

Heightened energy security



Weaker economic growth

Changing mix of global energy supplies



Key points

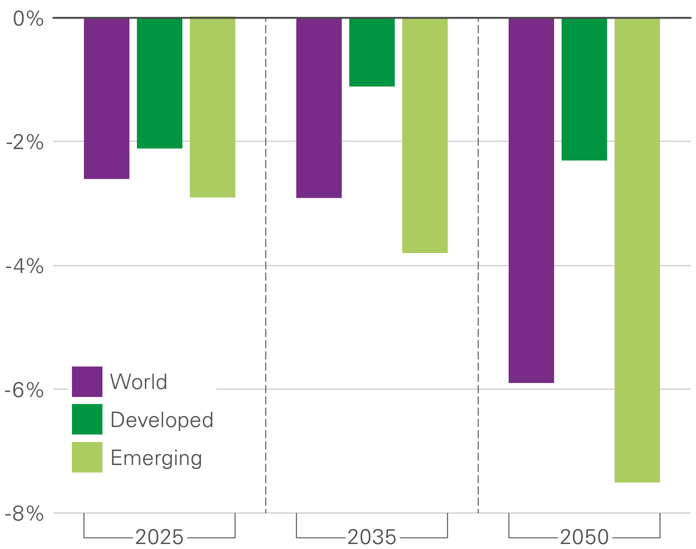
The Russia-Ukraine war is likely to have a persistent effect on the future path of the global energy system, increasing the focus on energy security, weakening economic growth, and changing the mix of energy supplies.

- The past year has been dominated by the terrible consequences of the Russia-Ukraine war and its awful toll on lives and communities. Our thoughts and hopes are with all those affected.
- From an energy perspective, this year's *Outlook* has modelled the impact of the Russia-Ukraine war as operating through three main channels: energy security, economic growth, and composition of global energy supplies. At the time of writing, the war is continuing with no end in sight; as such this analysis should be treated as preliminary and subject to change depending on future developments.
- *Energy security*: the increased focus on energy security triggered by concerns about energy shortages and vulnerability to geopolitical events is assumed to cause countries and regions to strive to reduce their dependency on imported energy and instead consume more domestically produced energy. It also gives greater incentive to improve energy efficiency, reducing the need for all types of energy.
- *Economic growth*: the higher food and energy prices associated with the Russia-Ukraine war have contributed to a sharp slowing in global economic growth. The direct economic impact of this commodity price shock is set to persist for the next few years. Further out, the war is assumed to reduce somewhat the pace of global integration and trade, as countries and regions heighten their focus on domestic resilience and reduce their exposures to international shocks. This slower pace of globalization leads to a small reduction in average economic growth over the next 30 years.
- *Composition of global energy supplies*: the future of Russian energy supplies is uncertain. The scenarios in this year's *Outlook* assume a persistent reduction in Russian exports of hydrocarbons. In the near term, this reflects the impact of voluntary and mandatory sanctions on Russian energy exports. Further out, it stems from the assumption that sanctions affecting Russia's access to foreign investment and technologies ease only gradually.
- More details on the assumptions used to model the impact of the Russia-Ukraine war can be found in the Annex (pages 116-117).

The Russia-Ukraine war leads to a downward revision in the outlook for global GDP and energy demand

Impact of Russia-Ukraine war on global GDP

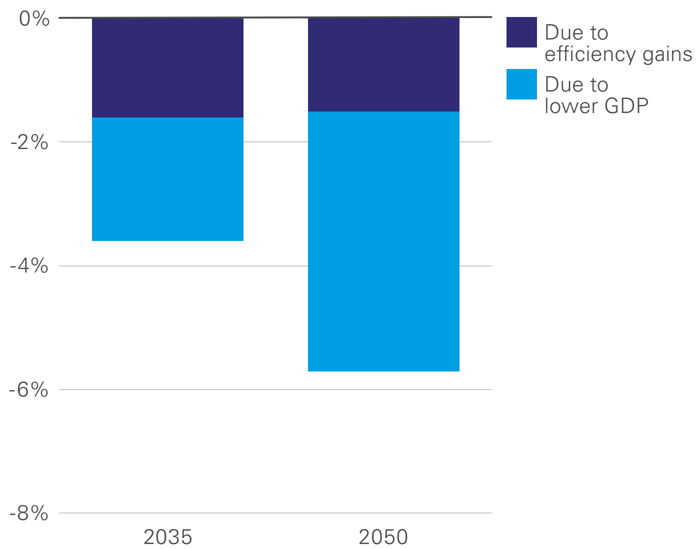
Change relative to EO22



EO22 = *Energy Outlook 2022*

Change in total final consumption in *Accelerated*

Change relative to EO22



Key points

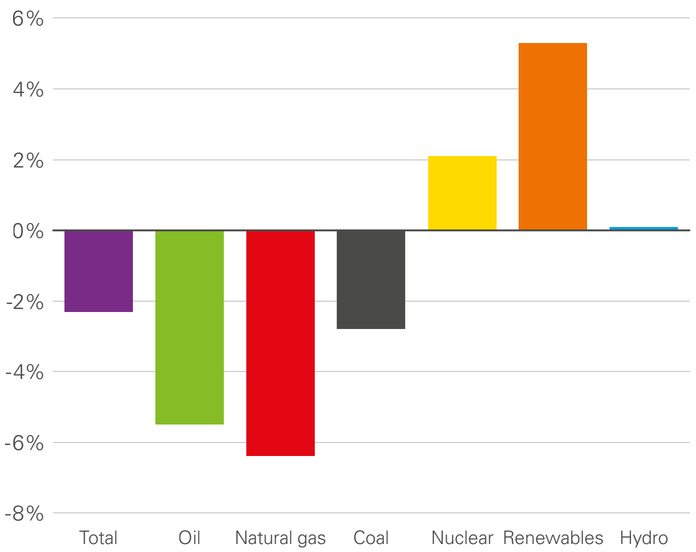
The prospects for global GDP and energy demand are weaker than in last year's *Outlook*, reflecting the short- and longer-term impacts of the Russia-Ukraine war.

- The level of global GDP underlying all three scenarios in this *Outlook* is around 3% lower in 2025 and 2035 than *Energy Outlook 2022* and around 6% lower in 2050.
- The weaker profile for economic activity over the near term is mostly driven by the commodity price shock associated with the Russia-Ukraine war. The direct impact of the commodity price shock largely fades by 2030, although the war is assumed to have a more persistent scarring effect on the Russian and Ukrainian economies.
- Beyond 2030, the lower level of GDP reflects the growing impact of the slower average (or trend) economic growth associated with the lower assumed paths of international trade and interconnectedness. Global GDP growth averages around 2.4% p.a. (on a Purchasing Power Parity basis) over the outlook, compared with 2.6% in *Energy Outlook 2022*.
- The impact of this reduction in trend economic growth is greatest in those regions that benefit the most from international trade and productivity transfers. In 2050, GDP in China is 7% lower than in last year's *Outlook* and is 12% lower in Africa, but is only 1% lower in the US.
- As in recent *Energy Outlooks*, the assumed trajectory for global GDP includes an estimate of the impact of climate change on economic growth. This includes the impact of both increasing temperatures on economic activity and the upfront costs of actions to reduce carbon emissions. More details of the approach and its limitations can be found in the Annex (see pages 118-119).
- The level of total final energy consumption is also weaker than in the previous *Outlook*, down by around 3.5% in 2035 across all the scenarios and by between 5.5%-6% in 2050.
- In 2035, slightly over half of the downward revision in energy consumption in *Accelerated* reflects the weaker profile for GDP. The remainder is driven by greater gains in energy efficiency reflecting both the heightened focus on energy security and the impact of higher energy prices. By 2050, the lower level of GDP accounts for around three-quarters of the revision to energy consumption.

Increased energy security concerns trigger a shift towards a more local, lower-carbon energy mix

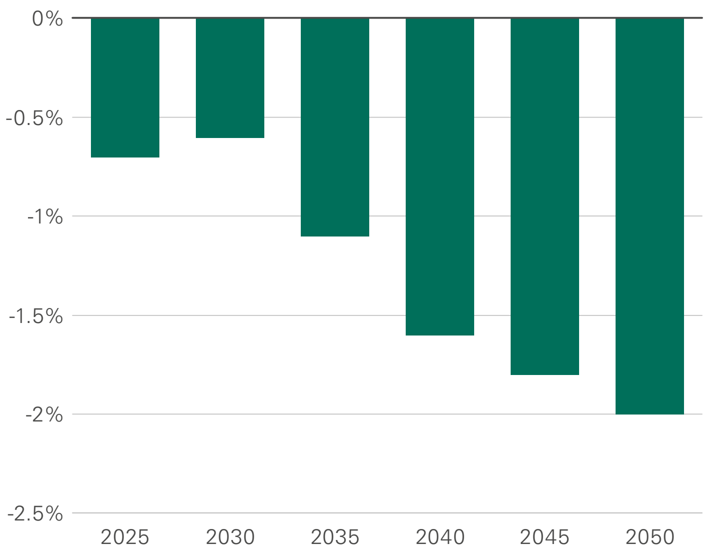
Change in primary energy in *New Momentum*

Change in 2035 relative to EO22



Change in carbon intensity in *New Momentum*

Change relative to EO22



Based on total final consumption. Impact of IRA not included.

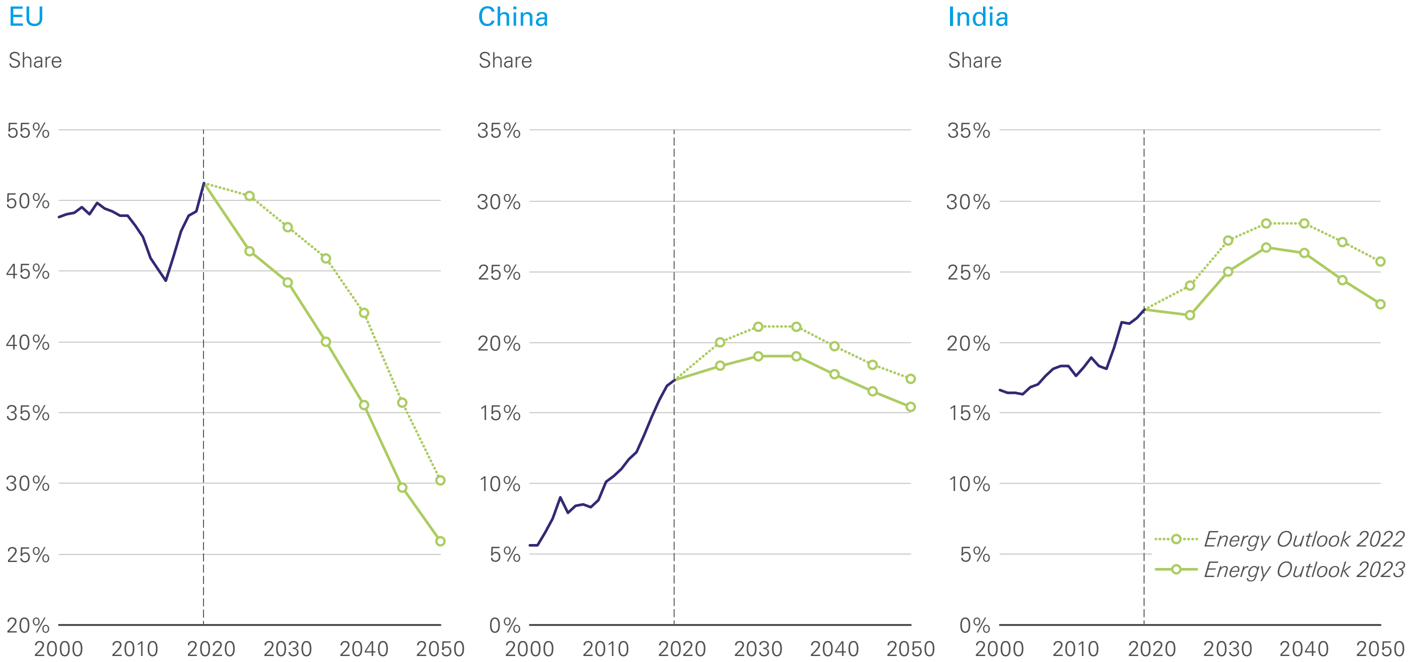
Key points

The increased importance placed on energy security as a result of the Russia-Ukraine war leads over time to a shift away from imported fossil fuels towards locally produced non-fossil fuels, accelerating the energy transition.

- Since oil and natural gas are the two most heavily traded fuels internationally, they are most impacted by the increased focus on energy security (see pages 22-23). In *New Momentum*, the 2% lower level of primary energy demand in 2035 relative to *Energy Outlook 2022* is largely accounted for by a 5% downward revision to oil demand and 6% lower natural gas demand. These effects are most concentrated in emerging Asia and the EU, both of which currently have significant reliance on oil and natural gas imports.
- Coal consumption is also lower than in last year's *Energy Outlook*, but the downward revision is smaller than for oil and natural gas. This reflects the continuing heavy use of domestic coal resources in many parts of Asia.
- In contrast to the downward pressure on oil and natural gas imports, and despite the lower level of overall energy demand, the consumption of energy that is produced locally is boosted as a result of the heightened energy security concerns. This particularly increases the use of non-fossil fuels as they tend to be produced and consumed locally. The use of renewables and nuclear energy in *New Momentum* in 2035 are higher than in last year's *Outlook*, while hydropower is largely unchanged.
- This shift towards locally produced non-fossil fuels at the expense of imported hydrocarbons helps to accelerate the energy transition (see pages 28-29). The carbon-intensity of the fuel mix in *New Momentum* by 2035 in this year's *Outlook* is around one percentage point lower than in *Outlook 2022*, and around two percentage points lower by 2050.

Energy security concerns reduce the role of oil and natural gas imports

Oil & gas imports as a share of primary energy in *New Momentum*



Key points

The increased preference for locally produced energy stemming from heightened energy security concerns reduces imports of oil and natural gas.

- The impact of increased energy security concerns on energy trade is most pronounced on oil and natural gas, which are the two most heavily traded fuels. This impact is especially marked in China and India, who currently import between 75%-85% of the oil they use and between 40-55% of their natural gas.

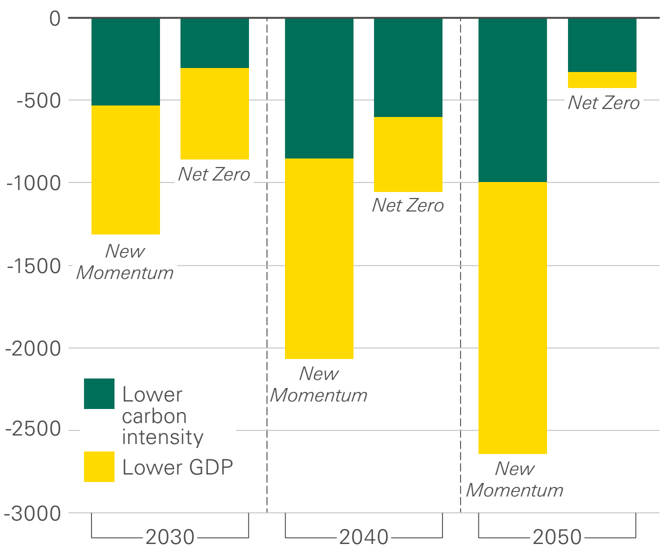
- The effect of heightened energy security concerns is also particularly evident in the EU given its previous dependence on natural gas imports from Russia, and its heavy dependence on oil and gas imports more generally. Together, the EU, China and India accounted for around 45% of global oil imports and around 50% of natural gas imports in 2021.

- In all three regions, heightened energy security concerns lead to a permanently lower share of imported oil and gas in primary energy. In 2035, their combined imports of oil and natural gas are over 10% lower in *New Momentum* than in *Outlook 2022*. Similar effects are apparent in *Accelerated* and *Net Zero*.

- The limited scope to increase domestic production of oil and natural gas in these countries and regions means that the reduced share of imported oil and gas in primary energy is offset by greater consumption of domestically produced renewables.

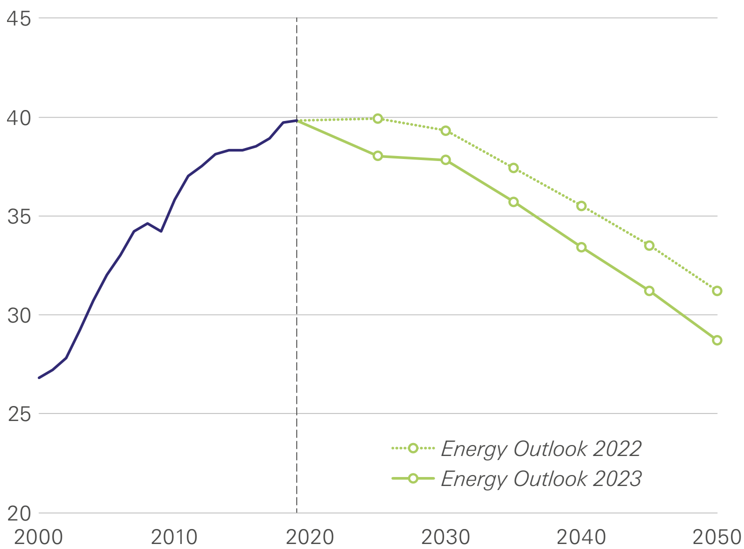
The Russia-Ukraine war and the Inflation Reduction Act lower the outlook for carbon emissions

Change in carbon emissions: EO23 versus EO22



CO_2 emissions form combusted fuels only
EO23 = *Energy Outlook 2023*

Carbon emissions: EO23 versus EO22 in *New Momentum*



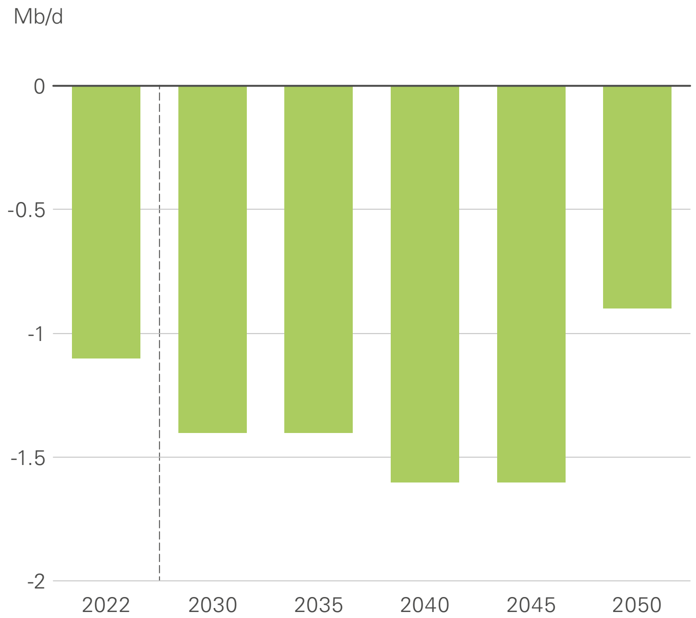
Key points

The impact of the Russia-Ukraine war, together with the policy support provided by the Inflation Reduction Act, reduces carbon emissions over the outlook.

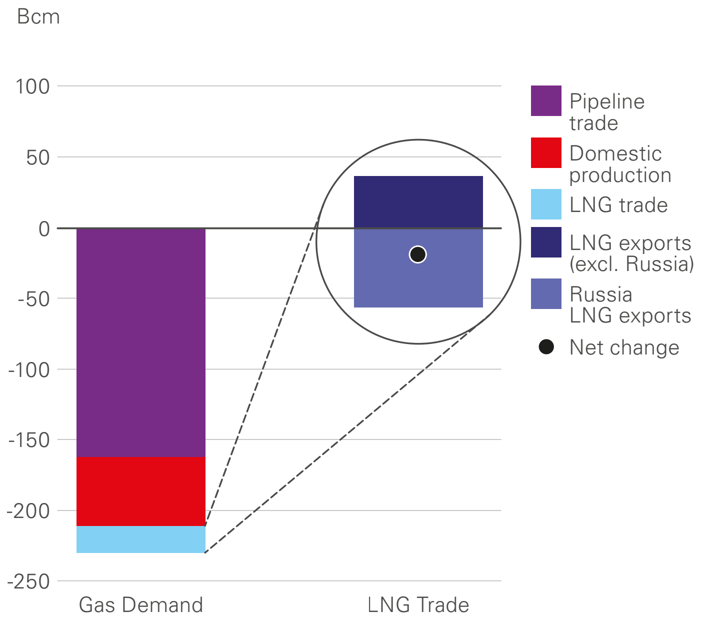
- Carbon emissions in this year's *New Momentum* are around 1.3 $GtCO_2$ (3.7%) lower in 2030 than in *Energy Outlook 2022*. This downward revision increases to around 2.0 $GtCO_2$ (6.4%) in 2040 and 2.6 $GtCO_2$ (9.3%) in 2050.
- The lower level of carbon emissions in *New Momentum* is largely driven by the weaker GDP profile caused in the near term by the impact of the war on commodity prices, and further out by the reduction in the pace of growth of global integration and trade. The impact of weaker economic activity increases over the outlook as the effect of the slower trend rate of growth compounds over time.
- The lower profile for carbon emissions in *New Momentum* also reflects more rapid reductions in the carbon intensity of GDP – the amount of carbon emitted per unit of GDP produced – largely reflecting the shift towards locally produced non-fossil fuels prompted by heightened energy security concerns. The support for low-carbon energy sources and technologies in the US provided by the IRA also contributes to this faster decline in the carbon intensity of GDP (see pages 26-27).
- The downward revision to carbon emissions in *New Momentum* from 2035 onwards averages around 2.2 $GtCO_2e$ per year – roughly the amount by which global carbon emissions fell in 2020 as a result of COVID lockdowns.
- The downward revision of carbon emissions in *Net Zero* is less than in *New Momentum*, averaging around 0.8 $GtCO_2$ per annum over the outlook. This smaller impact reflects the greater level of decarbonization in *Net Zero*, which means that the reduced level of energy demand stemming from the weaker GDP profile leads to a smaller saving in carbon emissions than in *New Momentum*.
- The reduction in carbon intensity in *Net Zero* by 2050 compared to that in *Outlook 2022* is also less than in *New Momentum*, reflecting the smaller impact of energy security concerns in *Net Zero* as the energy system decarbonizes and becomes increasingly dominated by non-fossil fuels – the majority of which are produced locally.

Russian production of oil and natural gas revised down as a result of the war

Change in Russian oil production: EO23 versus EO22 in *New Momentum*



Changes in natural gas by type of supply and in LNG trade in 2030: EO23 versus EO22 in *New Momentum*



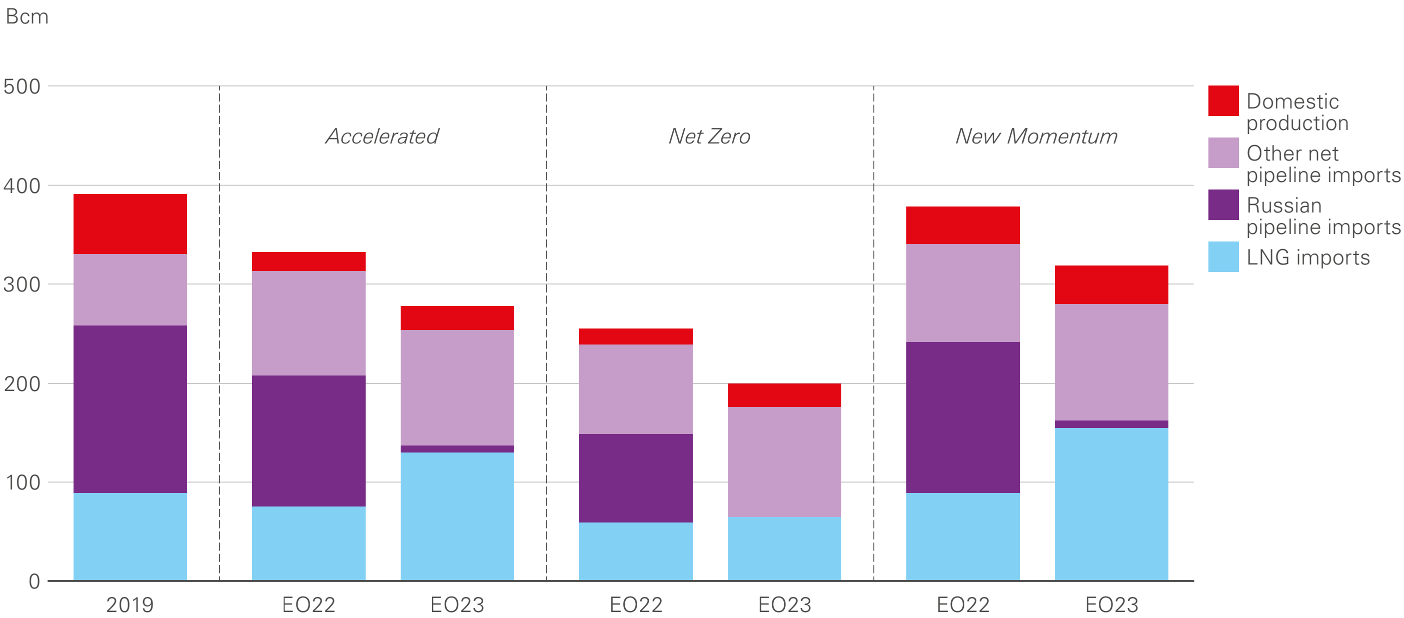
Key points

Prior to the Russia-Ukraine war, Russia was the world's largest energy exporter. The impact of the war reduces Russia's production of both oil and natural gas.

- Oil: The prospects for Russian oil production in the near-term are affected most significantly by the formal and informal sanctions on imports of Russian oil. Further out, the outlook is most heavily influenced by the impact of sanctions on Russia's access to western technology and investment.
- In *New Momentum*, Russian oil production over much of the outlook is around 1.3 Mb/d (13%) lower than in *Outlook 2022*. This reflects a combination of faster decline rates of existing operating assets and a curtailing of new prospective developments. There are similar-sized downward revisions in *Accelerated* and *Net Zero*. As a result, Russian oil production declines from around 12 Mb/d in 2019 to between 7 and 9 Mb/d in 2035 across the three scenarios.
- Natural gas: The combination of weaker GDP and a reduced preference for imported gas due to energy security concerns means that natural gas demand in the three scenarios in 2030 is between 130-250 Bcm (3.5-5%) lower in this year's *Energy Outlook* than in *Outlook 2022*.
- Most of this downward revision in gas demand is matched by reduced pipeline gas trade, driven by the almost total elimination of Russian pipeline exports to the EU. Production of gas for domestic use is also slightly lower. Outside of Russia, this fall takes place principally in the US as the shift to the use of alternative lower carbon energies there accelerates.
- The level of global LNG trade in 2030 in the three scenarios is similar to that in last year's *Outlook*. However, the geographical pattern of that trade is different. Restrictions limiting Russia's access to external finance and technology mean that the significant expansion in Russia's LNG exports envisaged in *Energy Outlook 2022* largely fails to materialize. Offsetting that, the level of non-Russian LNG exports in 2030 in this year's *Outlook* has been revised up by around 25-40 Bcm in *New Momentum* and *Accelerated*, with the US accounting for more than half of those additional exports.

EU's need for LNG imports in 2030 depends on its success in reducing natural gas demand

EU natural gas demand and sources of supply: EO23 compared with EO22



Key points

The EU is at the epicentre of the disruptions to global natural gas markets following the reductions in Russian pipeline gas exports. The extent to which the loss of Russian pipeline exports requires the EU to source alternative supplies of gas depends on how successful it is in reducing its demand for natural gas as it decarbonizes its energy system.

- The EU's desire to reduce its dependency on imported gas given the increased energy security concerns, combined with the weaker GDP profile, means EU natural gas demand in the three scenarios in 2030 is around 50-60 Bcm lower in this year's *Outlook* relative to *Energy Outlook 2022*.

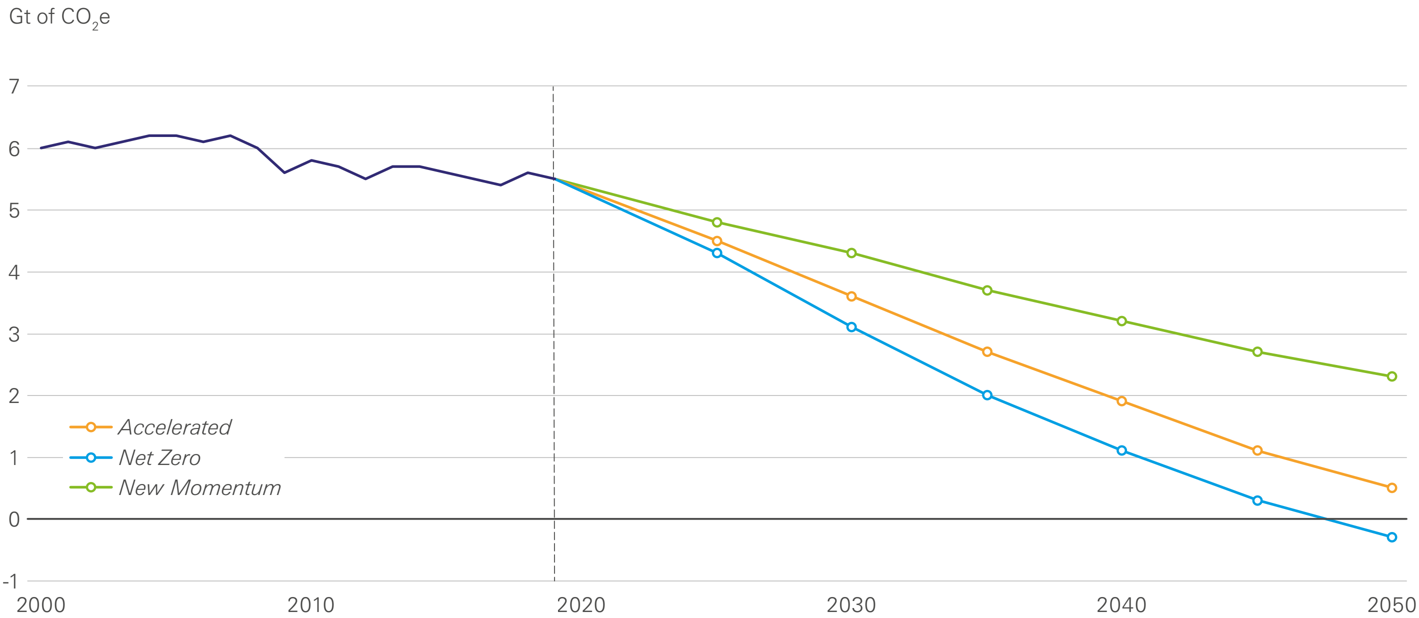
- In last year's *New Momentum*, EU gas demand in 2030 was only modestly lower than its level in 2019. EU gas demand is lower in this year's *Outlook*. However, the larger fall in Russian exports of pipeline gas means EU's LNG imports in 2030 in *New Momentum* are around 70 Bcm higher than in 2019. The remaining shortfall of natural gas left by the loss of Russian pipeline gas is met by increased pipeline imports from a combination of Norway, Algeria, and Azerbaijan.

- A similar change in gas demand is seen in *Accelerated*. Although EU consumption of natural gas in 2030 is around 30% lower than 2019 levels, a significant increase in LNG imports (40 Bcm) in 2030 relative to 2019 levels is nonetheless needed to meet demand, in the absence of Russian pipeline gas.

- In contrast, in *Net Zero*, a combination of faster gains in energy efficiency, rapid growth of wind and solar power and increasing electrification of final energy consumption means EU natural gas demand in 2030 is around 50% (190 Bcm) below 2019 levels. This reduction in demand is greater than the loss of Russian pipeline gas imports, implying that the level of LNG imports needed to meet the EU's domestic gas consumption in 2030 is lower than in 2019.

The Inflation Reduction Act provides significant support for low-carbon energy and technologies in the US

US Carbon emissions



Key points

The US Inflation Reduction Act (IRA), which was signed into law in August 2022, includes a significant package of largely supply-side measures supporting low-carbon energy sources and decarbonization technologies in the US.

- The modelling of the IRA in this *Outlook* focuses on its potential impact on the US energy system. The possible impacts on other countries and regions are not considered, although in practice the IRA has the potential to have positive spillover effects by helping to reduce global technology costs, expand internationally tradable supplies of some forms of low-carbon energy, and increase the pressure on other countries and regions to offer similar types of incentives.
- The impact of the IRA depends importantly on the implementation of the incentives by the US authorities, as well as on regulatory reform at a state and federal level. It also hinges on the speed with which the private sector can obtain the various planning and permitting approvals needed to build out low carbon energy sources and technologies. The scenarios in this *Outlook* assume that there are no material changes in planning and permitting processes other than those directly affected by IRA provisions.
- The impact of the IRA on the outlook for the US energy system is concentrated in the *New Momentum* scenario. US carbon emissions fall by around 22% by 2030 in *New Momentum* relative to 2019 levels, and by around 60% by 2050. The scale of the policy support already embodied in *Accelerated* and *Net Zero* means the incremental impact of the IRA provisions on these scenarios is relatively limited.

Some of the main impacts of the IRA on *New Momentum* include:

- Wind and solar power: a substantial acceleration in solar and wind deployment, with capacity increasing more than four-fold by 2030 from 2019 levels. By 2050 solar and wind capacity is more than ten times higher than in 2019, with around 20% of installed capacity used to support green hydrogen production. This increase is underpinned by a corresponding acceleration in other enabling factors, particularly the expansion of the transmission grid.
- Hydrogen: significant support for low-carbon hydrogen supply, increasing its use to 4 mtpa in 2030 and to 26 mtpa in 2050. The hydrogen incentives are especially supportive of green hydrogen, which accounts for around 60% of US low-carbon hydrogen in 2050, compared with around 25% in *Energy Outlook 2022*.
- Electric vehicles: the provisions in the IRA that support electric vehicle ownership, combined with new vehicle manufacturer and state-level commitments, increase the size of the US electric vehicle parc by around 15% by the mid-2030s.
- Biofuels: the additional credits included in the IRA facilitate faster penetration of bioderived sustainable aviation fuel (SAF), such that it reaches around 1300 PJ in *New Momentum* in 2050, more than double the level projected in *Energy Outlook 2022*.
- Carbon capture, use and storage (CCUS): the increased incentives for CCUS in the IRA support its greater use in the power sector, as well as in industry and to produce blue hydrogen. With the IRA and other incentives, CCUS deployment in the US reaches over 100 mtpa by 2035 and close to 400 mtpa by 2050.

Oil

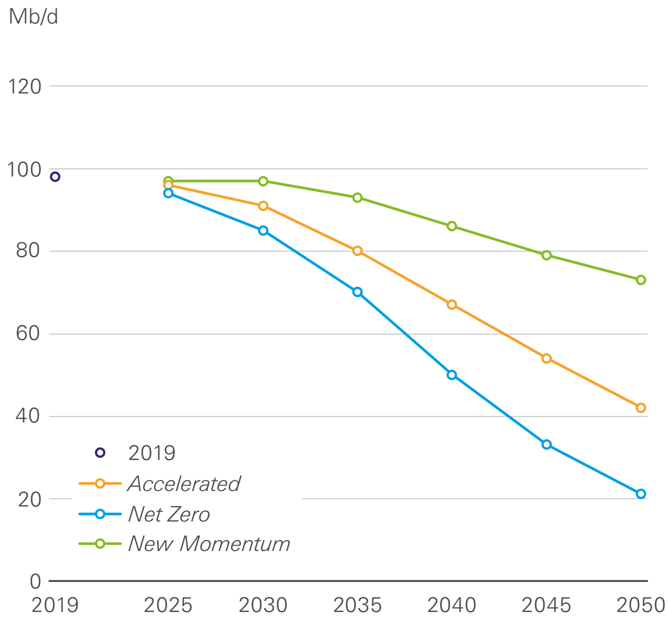
Oil demand falls over the outlook as use in road transportation declines

The role of oil in transport declines as the world switches to lower-carbon alternatives

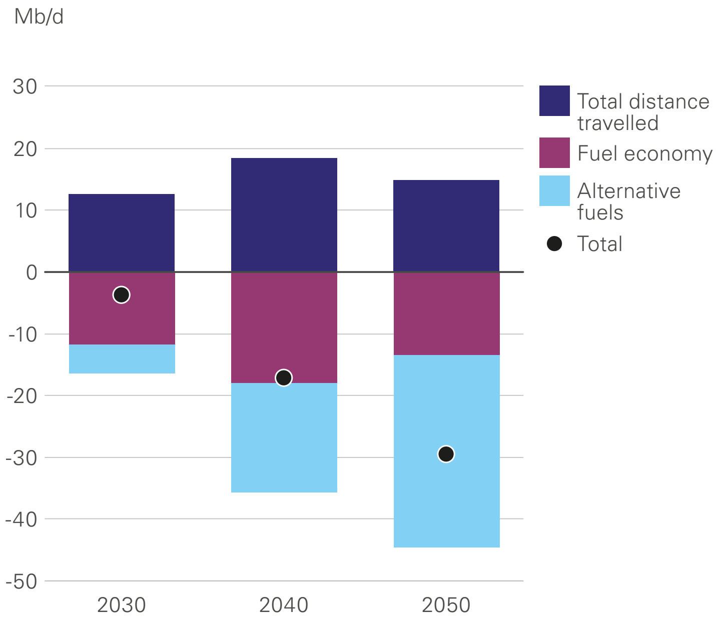
The changing mix of global oil supplies is dominated by trends in US tight oil and OPEC production

Oil demand falls over the outlook as use in road transportation declines

Oil demand



Change in oil demand in road transport versus 2019 in *Accelerated*

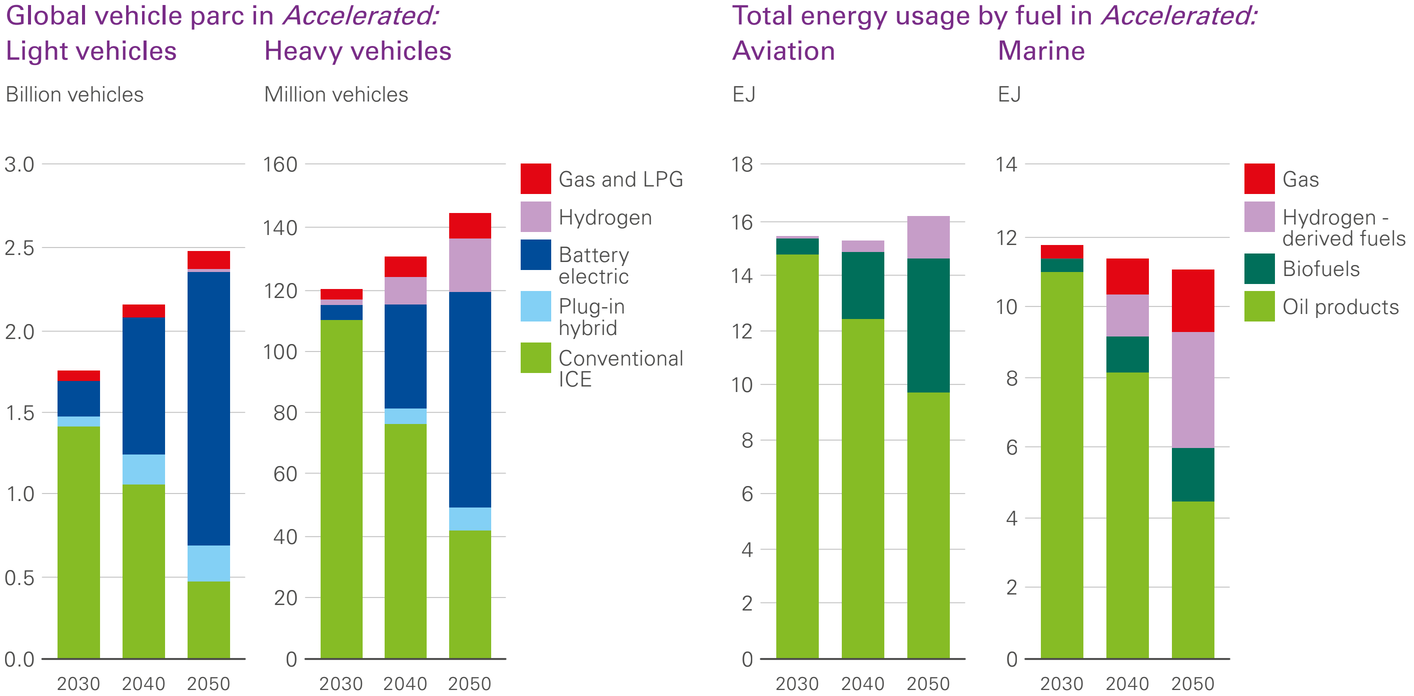


Key points

Global oil demand plateaus over the next 10 years or so before declining over the rest of the outlook, driven in part by the falling use of oil in road transport as vehicles become more efficient and are increasingly fuelled by alternative energy sources.

- Oil continues to play a major role in the global energy system over the first half of the outlook in *Accelerated* and *Net Zero*, with the world consuming between 70-80 Mb/d in 2035. The decline accelerates in the second half of the outlook, with oil demand reaching around 40 Mb/d in *Accelerated* and 20 Mb/d in *Net Zero* in 2050.
- Oil consumption in *New Momentum* is stronger, remaining close to 100 Mb/d through much of this decade, after which it declines gradually to around 75 Mb/d by 2050.
- Oil demand in emerging economies is broadly flat or gently rising over much of the first half of the outlook across the three scenarios, but this is offset by the accelerating declines in oil use in the developed world. These contrasting trends are reflected in a gradual shift in the centre of gravity of global oil markets, with emerging economies' share of global oil demand increasing from 55% in 2021 to around 70% in 2050 in all three scenarios.
- The single biggest factor driving the decline in oil consumption is the falling use of oil within road transport. Rising prosperity and living standards in emerging economies support an increase in both the size of the global vehicle parc and in distances driven, boosting the demand for oil. But this is increasingly offset by a combination of the road vehicle fleet becoming more efficient and the growing switch away from oil to alternative energy sources.
- Lower demand for oil in road transport accounts for more than half of the reduction in total oil demand in *Accelerated* throughout the outlook. In 2030, this largely reflects the impact of the increasing efficiency of the global vehicle fleet, which is more than twice that of the switch to alternative energy sources. By 2040 these two effects are broadly equal, and by 2050 the switch to alternative energy sources, led by the increasing electrification of vehicles, accounts for more than twice the impact on oil demand than the effects of greater efficiency.

The role of oil in transport declines as the world switches to lower-carbon alternatives



Gas includes biomethane

Key points

The role of oil falls across all modes of transport, reflecting a shift to alternative, low-carbon energy sources. That shift is dominated by electrification in road transport and by bio- and hydrogen-derived fuels in aviation and marine.

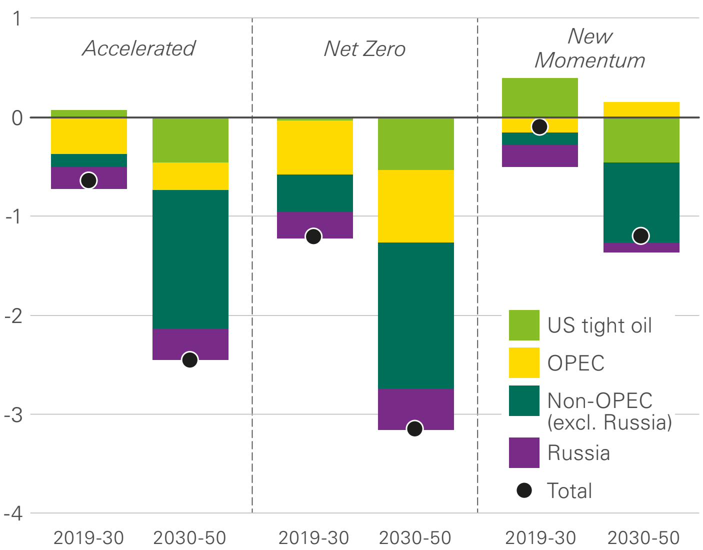
- In road transportation, the number of electric (including plug-in hybrid) cars and light-duty trucks increases from around 20 million in 2021 to between 550-700 million (30-35% of that vehicle parc) by 2035 in *Accelerated* and *Net Zero*, and to around 2 billion such vehicles (around 80%) by 2050. Electric passenger cars account for the majority of new car sales by the mid-2030s in *Accelerated* and *Net Zero*, supported by a combination of tighter regulation of vehicle emissions, improving cost and choice competitiveness of electric cars, and growing preference and acceptability among consumers.
- Although the electrification of cars and light duty trucks is less rapid in *New Momentum*, there are still around 500 million such vehicles by 2035 and 1.4 billion by 2050, with electric passenger cars accounting for around 40% of new car sales in 2035 and 70% in 2050.
- There is also a switch away from the reliance on diesel in medium- and heavy-duty trucks and buses, with the share of diesel-based trucks in the global parc declining from around 90% in 2021 to between 70-75% in 2035 in *Net Zero* and *Accelerated* and 5-20% in 2050. The main switch is to electrification, but hydrogen-fuelled trucks also play a growing role, especially for heavy-duty, long-distance use cases. The choice between electrification and hydrogen varies across different countries and regions depending on policies affecting the relative price of electricity and low-carbon hydrogen, as well as on regulatory policies and the development of charging and refuelling infrastructures.
- Electrification of road vehicles is initially dominated by China, Europe and North America, which together account for around 60-75% of the growth of electric road vehicles* to 2035 in the three scenarios and 50-60% of the growth to 2050.
- Oil continues to dominate the aviation sector over the first half of the outlook, but its share declines to around 60% of energy used in aviation by 2050 in *Accelerated* and 25% in *Net Zero*, offset by the increasing use of sustainable aviation fuel (SAF). In *Accelerated*, the majority of the SAF is derived from bioenergy (biojet). Biojet also provides most of the SAF in Net Zero, although by 2050 there is also a greater role for hydrogen-derived fuels (synthetic jet fuel – see pages 70-71).
- The main alternative to oil-based products in marine use is provided by hydrogen-based fuels (ammonia, methanol and synthetic diesel). The penetration of these fuels is concentrated in the second half of the outlook in *Accelerated* and *Net Zero*, where they account for between 30% and 55% of total energy used in marine by 2050. In contrast, oil continues to account for more than three-quarters of marine energy demand in 2050 in *New Momentum*.

*Excluding e-bicycles

The changing mix of global oil supplies is dominated by trends in US tight oil and OPEC production

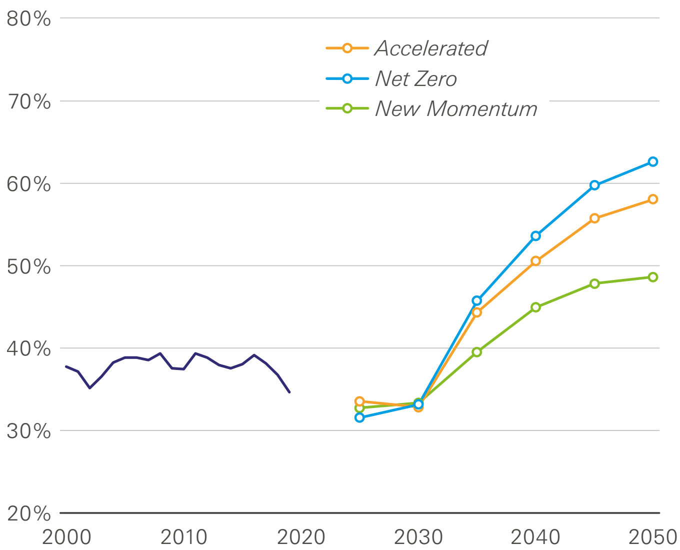
Change in oil supply

Average annual change, Mb/d



OPEC market share of global oil supply

Share of total



Key points

The composition of global oil supplies shifts over time, as US tight oil grows over the rest of this decade after which it declines as the most productive locations are exhausted and OPEC competes to increase its market share. There is a sustained decline in Russian production.

- US tight oil – including natural gas liquids (NGLs) – grows over the first 10 years or so of the outlook, peaking at between 11-16 Mb/d around the turn of this decade in all three scenarios. Brazilian and Guyana output also increases over the next 10 years or so, reaching around 5 Mb/d and 2 Mb/d respectively by the mid 2030s.
- US production falls through the 2030s and 40s, as US tight formations mature, and OPEC adopts a more competitive strategy against a backdrop of accelerating declines in oil demand. US tight oil drops to around 2 Mb/d or less in *Accelerated* and *Net Zero* by 2050, and to around 6 Mb/d in *New Momentum*, where the pressures from falling levels of overall demand are less acute.
- Russian output declines over the entire outlook, falling from around 11.5 Mb/d in 2019 to between 5.5-6.5 Mb/d in 2035 in *Accelerated* and *Net Zero* and to 2.5 Mb/d or less by 2050. The reductions in *New Momentum* are less pronounced, with Russian production falling to around 8.5 Mb/d and 7 Mb/d in 2035 and 2050 respectively.
- OPEC's production strategy reacts to the changing competitive landscape. OPEC lowers its output over the first decade of the outlook in response to the growth in US and other non-OPEC supplies, accepting a lower market share to mitigate the downward pressure on prices. The fall in OPEC's market share is most pronounced in *Accelerated* and *Net Zero* given the backdrop of falling oil demand from the mid-2020s.
- As the decline in oil demand gathers pace through the second half of the outlook and the competitiveness of US output wanes, OPEC competes more actively, raising its market share. OPEC's share of global oil production increases to between 45-65% by 2050 in all three scenarios.
- The higher cost structure of non-OPEC production means between 75-85% of the fall in oil production in *Accelerated* and *Net Zero* by 2050, and virtually all the reduction in *New Momentum*, is borne by non-OPEC suppliers.

Natural gas

Prospects for natural gas depend on the speed of the energy transition

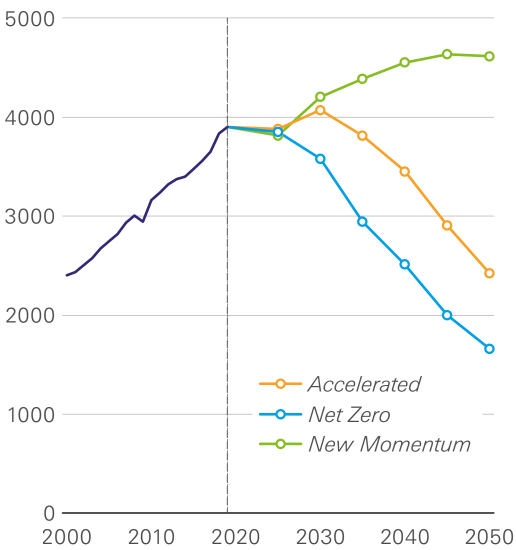
LNG trade increases in the near term, with the outlook becoming more uncertain post 2030

LNG exports are dominated by the US and the Middle East

Prospects for natural gas depend on the speed of the energy transition

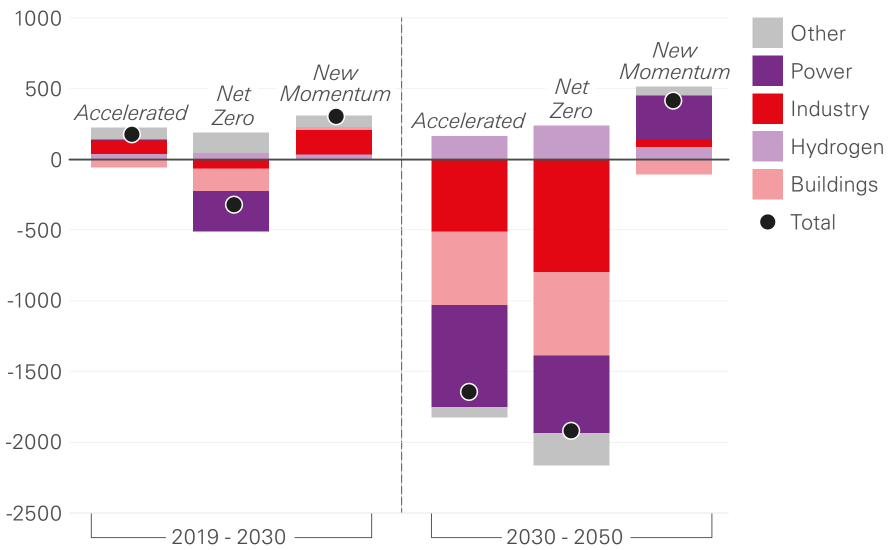
Natural gas demand

Bcm



Change in natural gas demand by sector

Change, Bcm



Key points

The prospects for natural gas depend on the outcome of two significant but opposing trends: increasing demand in emerging economies as they grow and industrialize, offset by a shift away from natural gas to lower-carbon energy led by the developed world. The net impact of these opposing trends on global gas demand depends on the pace of the energy transition.

- Global demand for natural gas rises over the rest of this decade in *New Momentum* and *Accelerated* driven by strong growth in China – underpinned by continued coal-to-gas switching – and also by India and other emerging Asia as they industrialize further.

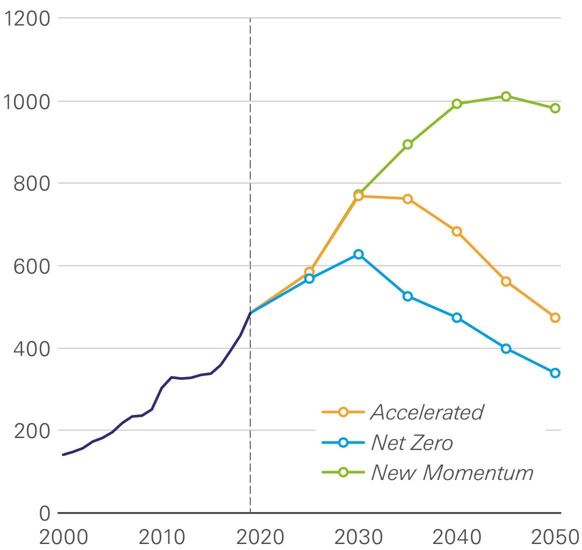
- In contrast, natural gas consumption in *Net Zero* peaks in the mid-2020s before then starting to decline. The use of gas within the emerging world grows out to 2030. But this growth is outweighed by falling consumption in the developed world, given the shift towards electrification and lower carbon energy.

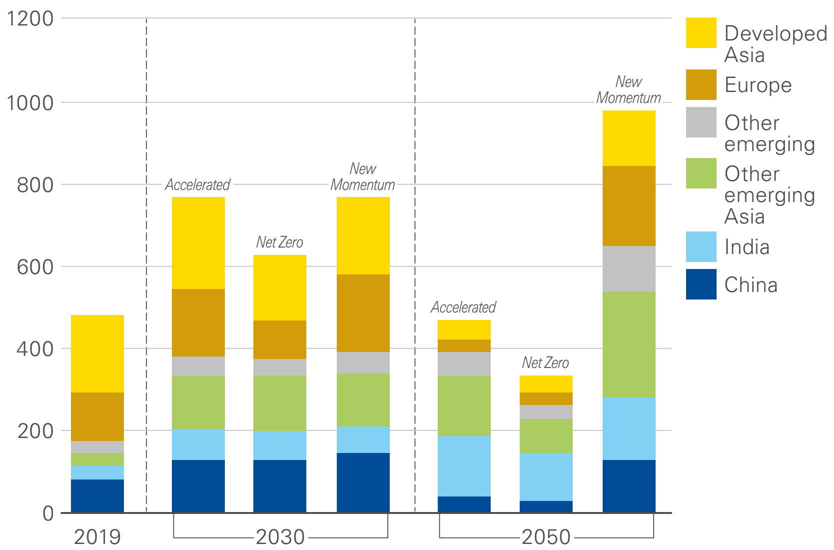
- From the early 2030s onwards, natural gas demand declines in *Accelerated* and *Net Zero* as the sustained decline in its use in the developed world is compounded by falling demand in China and the Middle East, driven by the same patterns of increasing electrification and rapid growth in renewable energy. The decline is only partially offset by the growing use of natural gas to produce blue hydrogen (see pages 72-73). By 2050, natural gas demand is around 40% lower than 2019 levels in *Accelerated* and 55% lower in *Net Zero*.

- In contrast, global natural gas demand in *New Momentum* continues to grow for much of the period out to 2050, driven by growing use in emerging Asia and Africa. Much of this growth is in the power sector as the share of natural gas consumption in power generation in these regions grows and overall power generation increases robustly. Global natural gas demand in *New Momentum* in 2050 is around 20% above 2019 levels.

- The range of the difference in global gas demand in 2050 across the three scenarios relative to current levels is greater than for either oil or coal, highlighting the sensitivity of natural gas to the speed of the energy transition.

LNG trade increases in the near term, with the outlook becoming more uncertain post 2030





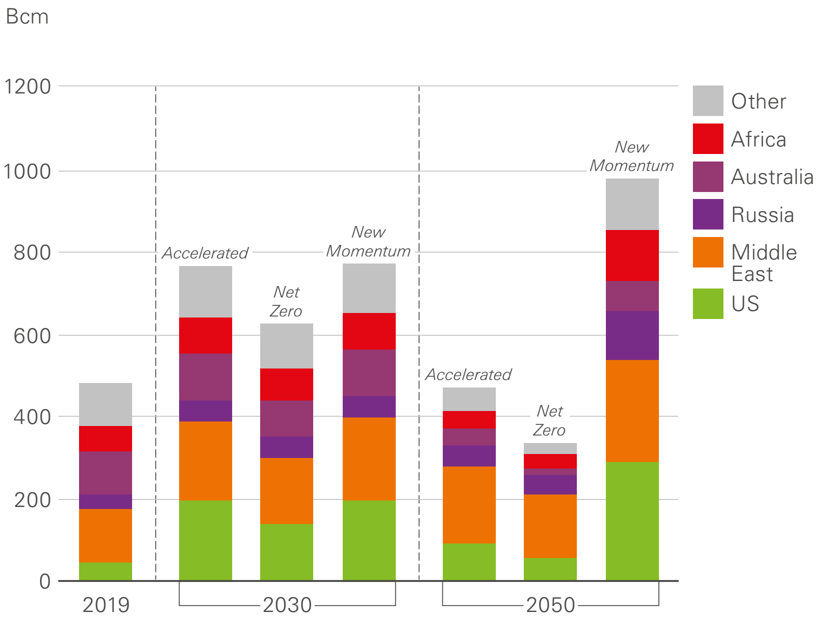
Key points

LNG trade increases robustly in the near term but the range of uncertainty widens post 2030, with continuing demand for LNG in emerging markets as they grow and industrialize, offset by falling import demand in developed markets as they transition to lower carbon energy sources.

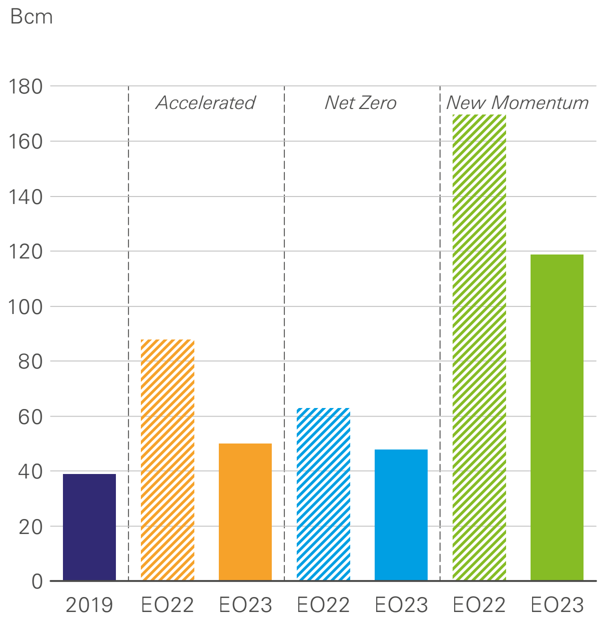
- LNG trade grows strongly over the first 10 years of the outlook, increasing by around 60% in *New Momentum* and *Accelerated* and by a third in *Net Zero*.
- Much of this growth is driven by increasing gas demand in emerging Asia (China, India, and other emerging Asia) as these countries switch away from coal and, outside of China, continue to industrialize. LNG imports are the main source for this growing use of natural gas, accounting for 65-75% of the increase in gas consumed in emerging Asia out to 2030 across the three scenarios.
- European LNG imports also increase materially out to 2030 in *New Momentum* and *Accelerated*, reflecting the fall in Russian pipeline imports and persistent natural gas demand (see pages 34-35).
- The range of uncertainty in LNG trade increases materially post 2030. Imports of LNG increase by around 30% between 2030 and 2050 in *New Momentum*, whereas they fall by around 40% over the same period in *Accelerated* and *Net Zero*.
- The growth in LNG demand post-2030 in *New Momentum* is driven by increasing demand from India and other emerging markets, reflecting the increasing use of natural gas in the power and industrial sectors (see pages 48-49). This growth in the emerging world more than offsets declining LNG imports in Europe and developed Asian markets.
- LNG demand in emerging economies also grows for much of the period post-2030 in *Accelerated* and *Net Zero*, but this is more than offset by sharp falls in LNG imports in developed Asian and European markets and in China, as these regions switch away from natural gas to lower carbon energy sources.
- The size of the LNG market in 2050 is roughly double its 2019 level in *New Momentum*, broadly unchanged in *Accelerated*, and is around 30% lower in *Net Zero*.

LNG exports are dominated by the US and the Middle East

LNG exports by region



Russia LNG exports in 2050



Key points

The US and Middle East establish themselves as the main global supply hubs for LNG exports, with the prospects for Russian LNG exports scarred by the effects of the Russia-Ukraine war.

- The growth in global LNG demand out to 2030 is met by a substantial expansion of exports from the US and Qatar. Growth in US LNG exports account for more than half of the increase in global LNG supplies out to 2030 in *New Momentum* and *Accelerated* and around two-thirds of overall growth in *Net Zero*. Growing exports from the Middle East account for much of the remainder. By 2030, the US and the Middle East together account for around half of global LNG supplies, compared with around a third in 2019.
- The fall in LNG exports in the second half of the outlook in *Accelerated* and *Net Zero* is borne disproportionately by the US. US LNG exports fall by more than a half between 2030 and 2050 in these two scenarios, reflecting the increasing competition and the higher transport costs for US supplies to the remaining demand centres in Asia relative to the cost of LNG from the Middle East and Africa.
- Australian LNG exports decline post-2030 in all three scenarios reflecting increasing costs and constraints on upstream natural gas production in Australia.
- Russian LNG exports out to 2030 are constrained by continuing restrictions on Russia's access to western technology and funding. As such, Russian exports over the first decade of the outlook are broadly flat, with only those projects close to completion before the start of the war assumed to start up.
- The constraints on Russia's access to technology and funding are assumed to ease gradually post-2030, allowing Russian LNG exports to more than double by 2050 in *New Momentum*. In contrast, the falls in global LNG demand in the 2030s and 40s in *Accelerated* and *Net Zero* means that Russian LNG exports do not have a chance to recover even as sanctions are eased. Russian LNG exports are between 10-60 Bcm lower in 2035 and 15-50 Bcm lower in 2050 across the three scenarios than in last year's *Energy Outlook* (see pages 32-33).

Renewable energy

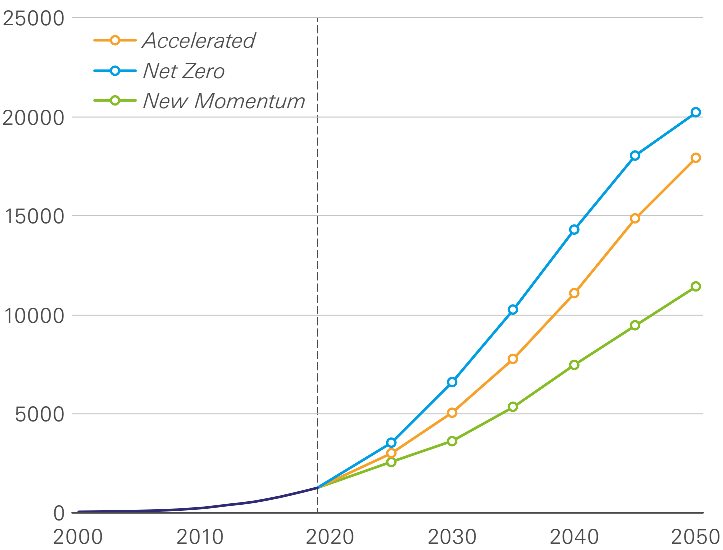
Wind and solar power expands rapidly, requiring significant acceleration in financing and building new capacity

Modern bioenergy expands rapidly, helping to decarbonize hard-to-abate sectors and processes

Wind and solar power expands rapidly, requiring significant acceleration in financing and building new capacity

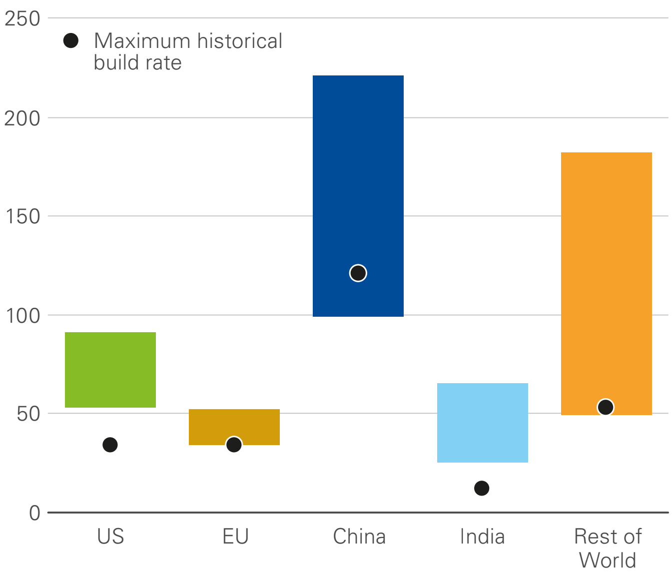
Installed wind and solar capacity

GW



Range of wind and solar capacity build rates in the three scenarios 2022-2035

GW per year



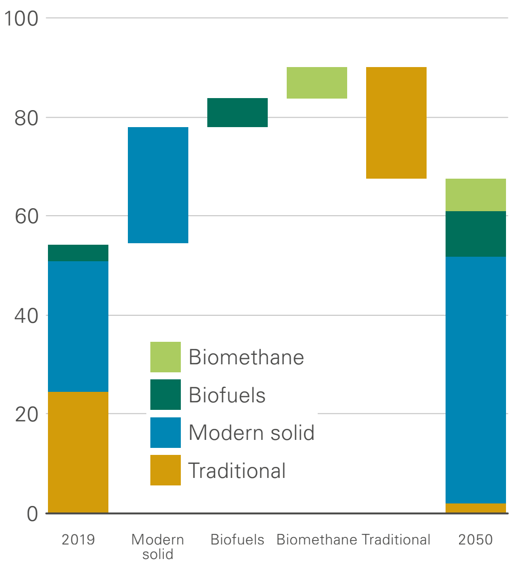
Key points

Wind and solar power expands rapidly, driven by increasing cost competitiveness and policies supporting a shift to low-carbon electricity and green hydrogen.

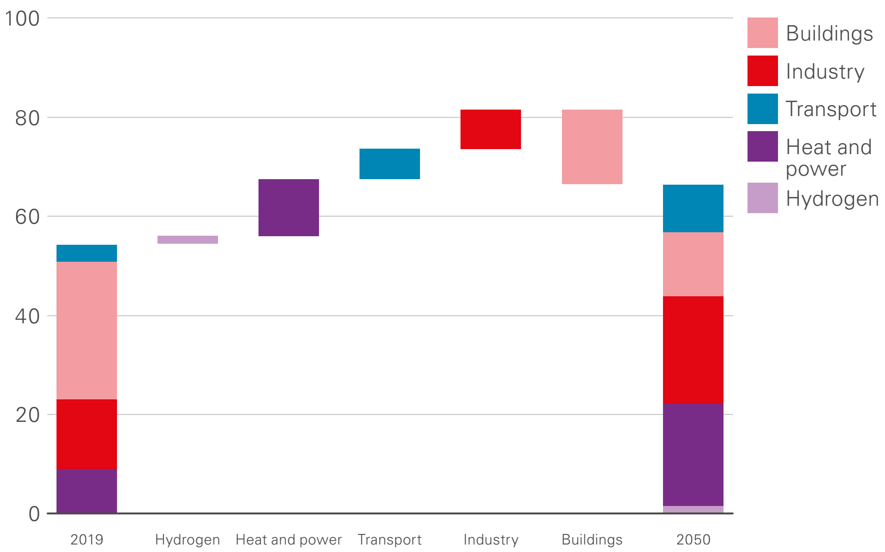
- Wind and solar installed capacity increases by around 15 fold over the outlook in *Accelerated* and *Net Zero* and 9 fold in *New Momentum*.
- Most of this capacity provides electricity for final consumption, although around a quarter to a third of the capacity by 2050 in *Accelerated* and *Net Zero* is used to produce green hydrogen.
- The rapid expansion in wind and solar power is largely underpinned by falls in their costs – which resume after recent short-term inflation pressures, especially over the first 10-15 years of the outlook. Solar and wind technology and production costs fall with growing deployment, supported by increases in module efficiency, load factors and project scales for solar, and by higher load factors of increasingly large turbines and lower operating costs for wind.
- The pace of cost reductions slows and eventually plateaus in the final two decades of the outlook as falling generation costs are offset by the growing expense of balancing power systems with increasing shares of variable energy sources. The outlook for costs assumes that the availability of the critical metals used in the manufacturing of photovoltaic modules and wind turbines increases sufficiently to avoid a sustained increase in prices (see pages 84-85). More generally, the scenarios are underpinned by an assumption that supply chains develop and expand so as to avoid excessive dependence on individual countries or regions for key materials, and the challenges around the security of supply of critical materials that might imply.
- The expansion in installed capacity by 2035 requires a significant acceleration of the pace at which new capacity is financed and built. The average rate of increase in installed capacity in *Accelerated* and *Net Zero* out to 2035 is 450-600 GW per year – around 1.9 to 2.5 times faster than the highest rate of increase seen in the past.
- In addition to a significant increase in investment (see pages 82-83), this rapid acceleration in the deployment of wind and solar capacity depends on a number of enabling factors scaling at a corresponding pace, including the expansion of transmission and distribution capacity, development of market frameworks to manage intermittency, the speed of planning and permitting, and the availability of route-to-market mechanisms.
- The growth in installed wind and solar capacity out to 2035 is dominated by China and the developed world, each of which accounts for 30-40% of the overall increase in capacity in all three scenarios. This pattern of growth switches significantly in the second half of the outlook, with emerging economies excluding China accounting for around 75-90% of the growth in the 2040s in *Accelerated* and *Net Zero*.

Modern bioenergy expands rapidly, helping to decarbonize hard-to-abate sectors and processes

Bioenergy supply by type in *Accelerated* (2019-2050)



Bioenergy demand by sector in *Accelerated* (2019-2050)



Key points

The use of modern bioenergy – modern solid biomass (such as wood pellets), biofuels and biomethane – increases significantly, helping to decarbonize hard-to-abate sectors and processes, and displacing the use of traditional biomass – such as waste wood and agricultural residues – for cooking and heating.

- There is a substantial shift from traditional to modern bioenergy in *Accelerated* and *Net Zero*, with modern bioenergy more than doubling to reach around 65 EJ by 2050, more than offsetting the phasing out of traditional biomass. Growth of modern bioenergy in *New Momentum* is slightly less pronounced, reaching close to 50 EJ by 2050. The expansion in modern bioenergy is achieved without any change in land use, with the vast majority sourced regionally through residues (from agriculture and forestry) and wastes which are accessible without detrimental effect to their ecosystems.
- The largest growth in demand for modern bioenergy is in solid biomass. Biomass is used mainly in the power sector, with its use in this sector almost tripling over the outlook in *Accelerated*. Much of the remainder is used to help decarbonize hard-to-abate industrial processes, especially in cement and steel manufacturing. In *Accelerated*, 5 EJ of biomass is used in conjunction with carbon capture and storage (BECCS) by 2050, predominantly in the power and industrial sectors. This use of BECCS in the power sector is concentrated in the developed world. Within emerging economies, biomass in the power sector is used in new biomass cogeneration plants and in co-firing plants with coal. The use of BECCS globally in *Net Zero* is greatest reaching 13 EJ in 2050, around half of which is deployed in the power sector, with much of the remainder used to produce hydrogen.
- The production of biofuels roughly triples in *Accelerated* and *Net Zero* by 2050 to around 10 EJ, with most of these fuels being used in the aviation sector. By 2050, bio-derived sustainable aviation fuel (biojet) accounts for 30% of total aviation demand in *Accelerated* and 45% in *Net Zero*, with 50-60% of the growth in biojet in the US and Europe, supported by increasing incentives and mandates.
- Biomethane grows significantly in all scenarios, from less than 0.2 EJ in 2019 to between 6-7 EJ in *Accelerated* and *Net Zero* by 2050 and 4.3 EJ in *New Momentum*. Biomethane is blended into the natural gas grid as a direct substitute for natural gas and is shared broadly equally across industry, buildings, and transport.
- In contrast to modern bioenergy, the role of traditional biomass is largely phased out by 2050 in *Accelerated* and *Net Zero*. That largely reflects its current use in buildings in emerging economies disappearing as access to electricity and clean-cooking fuels increases. The use of traditional biomass is more persistent in *New Momentum* reflecting the slower electrification of energy systems in emerging economies.
- The growth of modern bioenergy in all three scenarios is dominated by emerging economies, which account for around three quarters of the growth to 2050 in all three scenarios.

Electricity

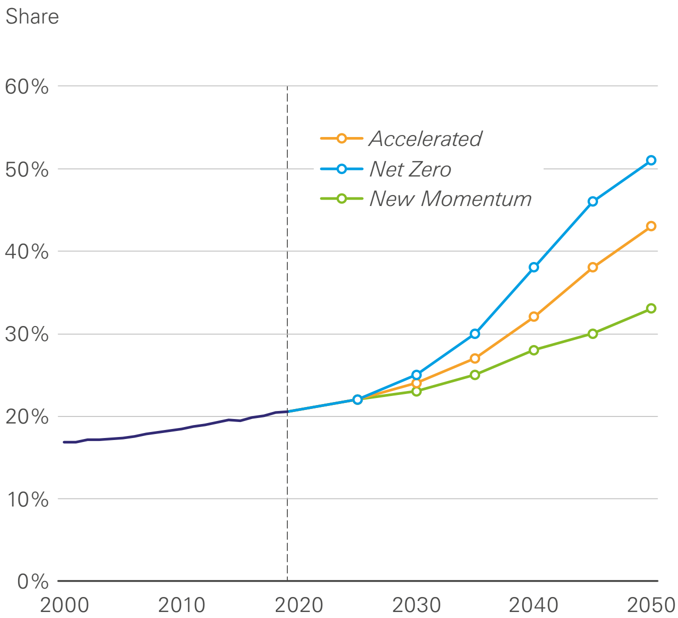
Electricity demand expands significantly as prosperity in emerging economies grows and the world increasingly electrifies

The global power system decarbonizes, led by the increasing dominance of wind and solar power

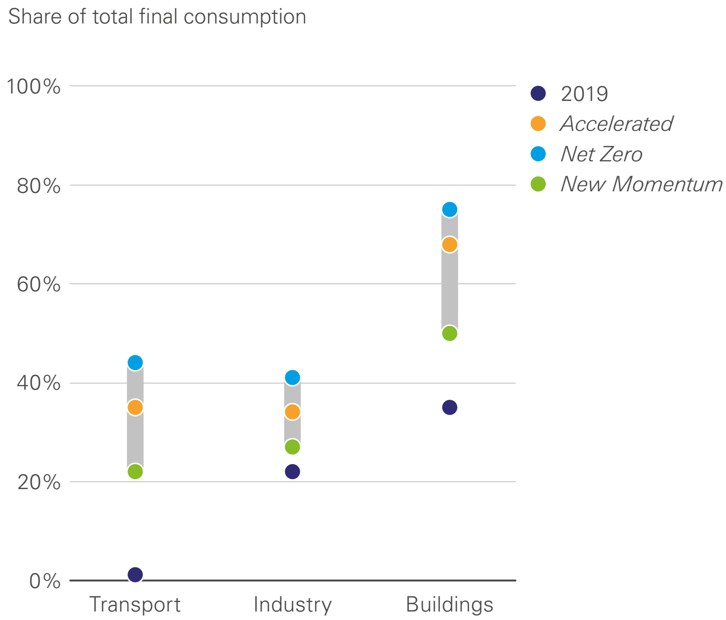
The mix of power generation differs between developed and emerging economies

Electricity demand expands significantly as prosperity in emerging economies grows and the world increasingly electrifies

Electricity as a share of total final consumption



Range of electrification across end-use sectors in 2050



Key points

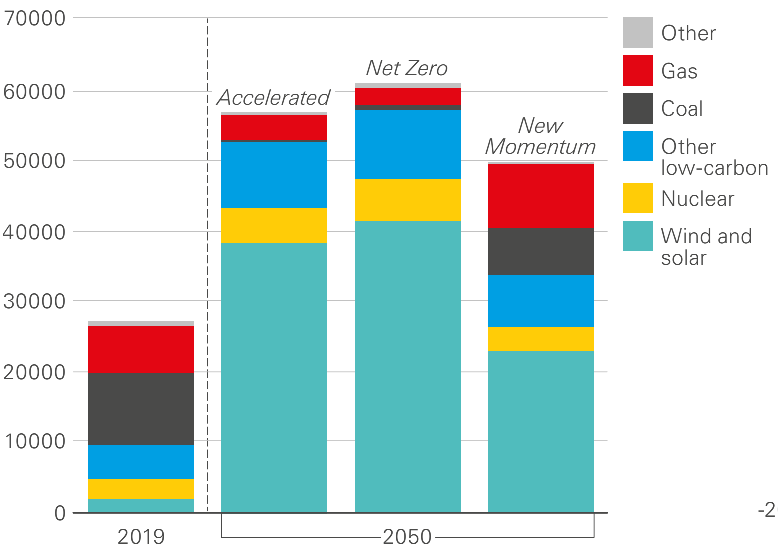
Electricity demand grows robustly over the outlook, driven by growing prosperity in emerging economies and increasing electrification of the global energy system.

- Final electricity demand increases by around 75% by 2050 in all three scenarios. The vast majority of this growth (around 90%) is accounted for by emerging economies as rising prosperity and living standards support a rapid expansion in the use of electricity.
- In developed markets, the increasing electrification of end energy uses underpins some growth in electricity consumption. But this growth is very modest compared with that in emerging economies.
- Electricity demand in India grows by between 250-280% over the outlook across the three scenarios, compared with 10-30% in the EU. Even so, electricity consumption per capita in the EU in 2050 is still around double that in India.
- The increasing electrification of the energy system is most pronounced in *Accelerated* and *Net Zero*, with the share of electricity in total final consumption (TFC) increasing from 20% in 2019 to between 40-50% by 2050. Despite the slower pace of decarbonization, the share of electricity in TFC in *New Momentum* still increases to over 30% by the end of the outlook.
- The increase in electrification is apparent across all-end-use sectors. The greatest scope for electrification is in buildings, where at least half of final energy demand is electrified by 2050 in all three scenarios. The higher degree of electrification of buildings' energy demand in *Accelerated* and *Net Zero* is largely driven by the greater adoption of heat pumps.
- The transport sector has the largest increase in the share of electrification relative to its current low level, largely reflecting the electrification of road transport (see pages 42-43).
- Compared with the other sectors, the scope for significant increases in the electrification of final energy use in industry is more limited, particularly for processes requiring high temperatures (>200°C).

The global power system decarbonizes, led by the increasing dominance of wind and solar power

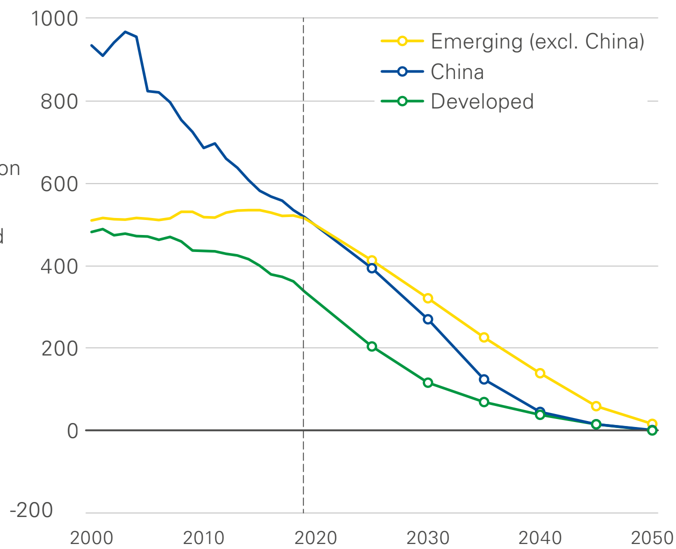
Electricity generation by fuel

TWh



Carbon intensity of power generation in *Accelerated*

gCO_2/kWh



Key points

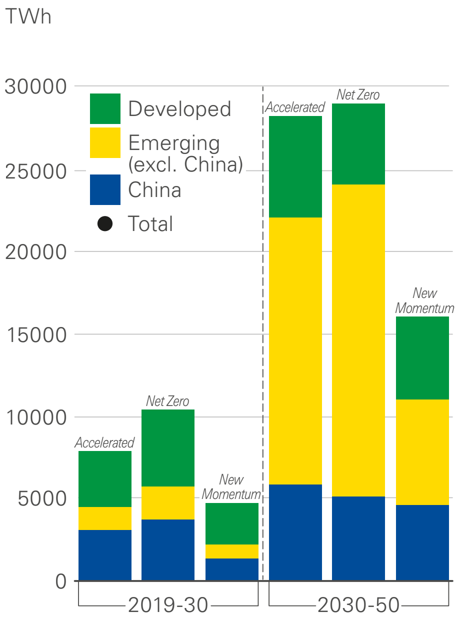
Global power generation decarbonizes, enabled by rapid growth in wind and solar power which accounts for all or most of the increase in power generation over the outlook.

- By 2050, wind and solar power account for around two-thirds of global power generation – and closer to 75% in the most advantaged regions – in *Accelerated* and *Net Zero*. That share is around a half by 2050 in *New Momentum*.
- Although direct electricity consumption is similar across the three scenarios (see pages 18-19), total power generation is higher in *Accelerated* and *Net Zero*, with an additional 15-20% of total generation by 2050 used to produce green hydrogen (see pages 72-73).
- Other sources of low-carbon power generation (nuclear, hydro, bioenergy and geothermal) continue to play a significant role, accounting for around 25% of global power generation in 2050 in *Accelerated* and *Net Zero*, similar to their share in 2019.
- Within that, nuclear power generation increases by around 80% by 2050 in *Accelerated* and more than doubles in *Net Zero*. Investment in new nuclear capacity is concentrated in China – which accounts for 50-65% of the growth in nuclear power in *Accelerated* and *Net Zero* – supported by new capacity in other emerging economies and an extension of lifetimes and restarting of existing plants in some developed economies.
- Coal is the fuel that loses most ground to the increasing dominance of low-carbon power, as its share in global power generation falls from close to 40% in 2019 to a little over 10% in *New Momentum* by 2050 and close to zero in *Accelerated* and *Net Zero*.
- The role of natural gas in global power generation is relatively stable over the first part of the outlook in *Accelerated* and *New Momentum*, given its continuing importance in the emerging world. But its use declines sharply in the second half of the outlook in *Accelerated* and *Net Zero* as the expansion of wind and solar power gathers pace. In 2050, 60-95% of the remaining gas-fired power generation in *Accelerated* and *Net Zero* is used in conjunction with carbon capture, use and storage (CCUS, see pages 76-77).
- In the second half the outlook, low-carbon hydrogen also emerges as a fuel in the power sector: although its overall share of generation is very small, it plays an important role as dispatchable low-carbon power in electricity systems with a high share of solar and wind.
- The increasing dominance of low-carbon energy, together with the use of CCUS, cause carbon emissions from power generation in *Accelerated* to fall by around 55% by 2035 and to be virtually eliminated by 2050. The reduction in the carbon intensity of global power generation over the first part of the outlook is led by the developed world and China, with emerging economies catching up over the second half of the period. Similar trends are also apparent in *Net Zero*, where the greater use of bioenergy combined with CCUS results in the power sector being a source of negative emissions by 2050.

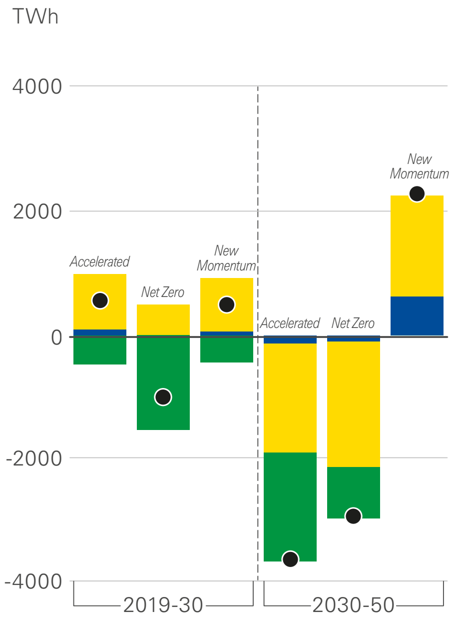
The mix of power generation differs between developed and emerging economies

Change in generation by source and region

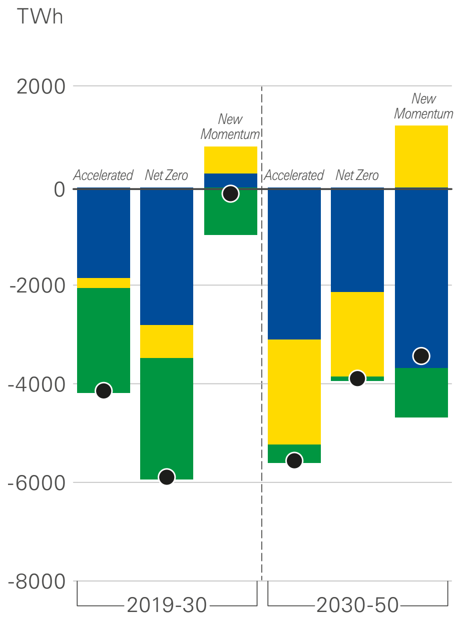
Wind and solar



Gas power



Coal power



Key points

The energy sources used to fuel the growth in power generation vary across developed and emerging economies, reflecting differences in their stages of development and in the maturity and size of power generation markets.

- Growth in wind and solar generation over the rest of this decade is dominated by China and the developed world, which together account for 80-85% of the growth in wind and solar power out to 2030 in the three scenarios.
- This share declines to 35-60% in the period after 2030 as the growth in renewable power generation in emerging economies (excluding China) rises sharply, underpinned by strong growth in power demand and the increasing ability of these markets to support a rapid build out of wind and solar capacity.
- The growth in gas-fired power generation over the rest of the current decade is concentrated in emerging economies. In *Accelerated* and *Net Zero*, the increase in gas-fired power generation and the rapid expansion in wind and solar power facilitate a modest reduction in coal generation by 2030 in emerging economies. That higher level of gas-fired power generation is relatively short-lived in *Accelerated* and *Net Zero*, as the push to decarbonize the power sector, led by a sharp acceleration in wind and solar power generation, triggers a reduction in both gas- and coal-fired generation after 2030.
- In contrast, the slower growth in power demand in developed economies, together with robust increases in renewable power generation, cause gas-fired generation in the developed world to plateau in the next few years in *Net Zero* and *Accelerated* before declining thereafter.
- The move to decarbonize the power sector causes coal-fired generation to decrease markedly in all regions in *Accelerated* and *Net Zero*. The use of coal is more persistent in *New Momentum*, with a small increase in coal generation in China and other emerging economies over the rest of this decade. But that rise is more than reversed by a sharp fall in Chinese coal generation in the final 20 years of the outlook. At a global level, the fall in total coal-fired generation is dominated by China, which explains around half of the total decline in *Accelerated* and *Net Zero* and more than the total in *New Momentum*.

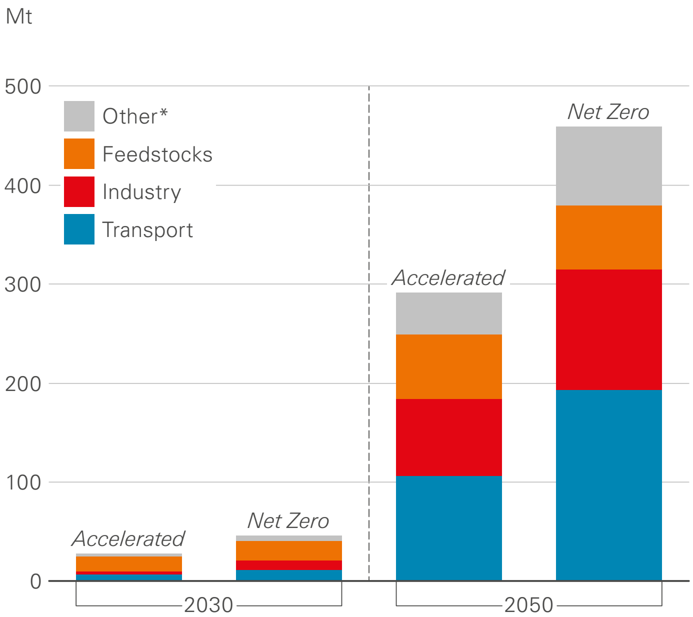
Low-carbon hydrogen

Low-carbon hydrogen plays a critical role in helping the energy system to decarbonize

Low-carbon hydrogen is dominated by green and blue hydrogen, with trade in hydrogen a mix of regional pipelines and global shipping

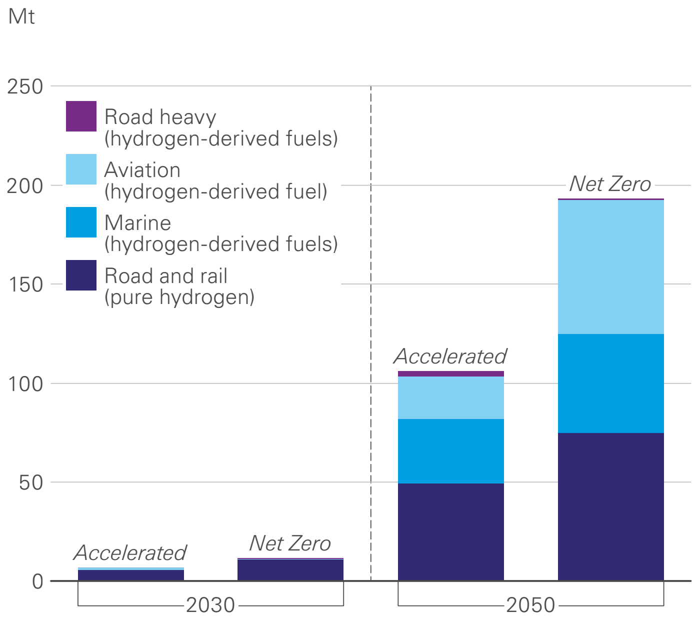
Low-carbon hydrogen plays a critical role in helping the energy system to decarbonize

Low-carbon hydrogen demand



*Other includes hydrogen demand for power, heating, and buildings

Low-carbon hydrogen demand in transport



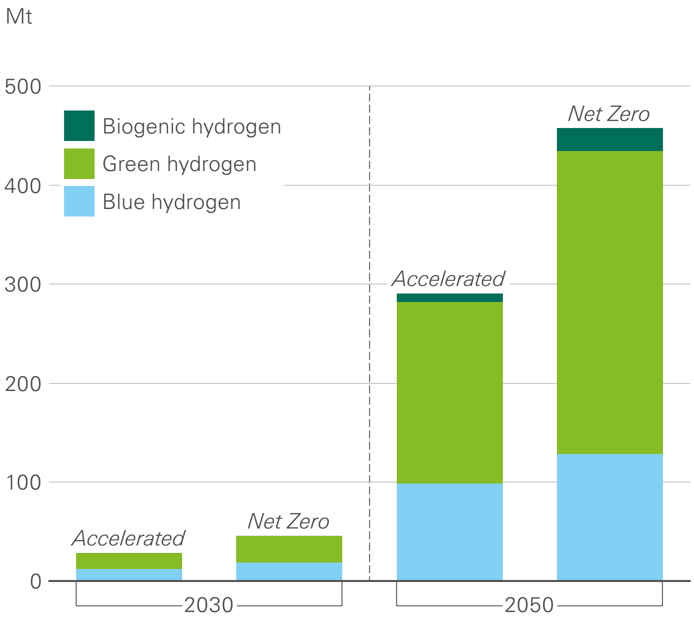
Key points

The use of low-carbon hydrogen grows as the world transitions to a more sustainable energy system, helping to decarbonize hard-to-abate processes and activities in industry and transport.

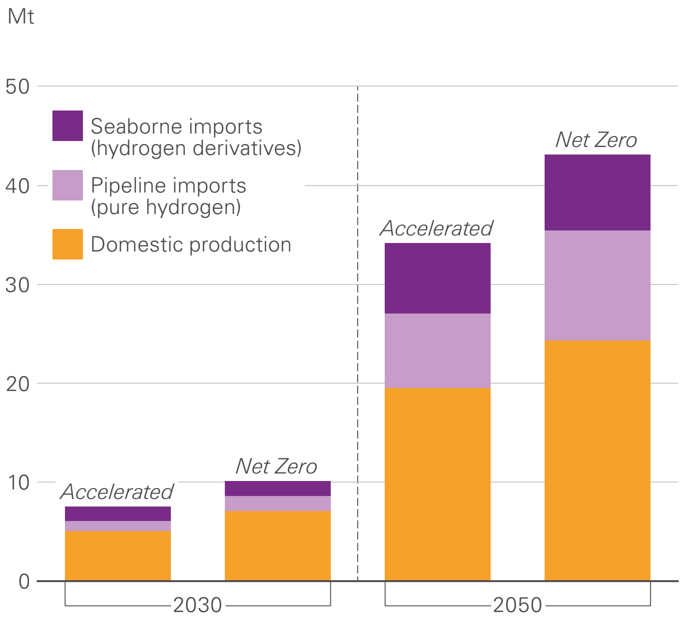
- The use of low-carbon hydrogen is most pronounced in *Accelerated* and *Net Zero*, complementing growing electrification of the energy system by acting as a carrier of low-carbon energy for activities that are difficult to electrify. The lower degree of decarbonization in *New Momentum* means low-carbon hydrogen plays a relatively limited role.
- The growth of low-carbon hydrogen during the first decade or so of the outlook is relatively slow, reflecting both the long lead times to establish low-carbon hydrogen projects and the need for considerable policy support to incentivize its use in place of lower-cost alternatives. The demand for low-carbon hydrogen by 2030 is between 30-50 Mtpa in *Accelerated* and *Net Zero*, the majority of which is used as a lower carbon alternative to the existing unabated gas- and coal-based hydrogen used as an industrial feedstock in refining and the production of ammonia and methanol.
- The pace of growth accelerates in the 2030s and 2040s as falling costs of production and tightening carbon emissions policies allow low-carbon hydrogen to compete against incumbent fuels in hard-to-abate processes and activities, especially within industry and transport. Demand for low-carbon hydrogen rises by a factor of 10 between 2030 and 2050 in *Accelerated* and *Net Zero*, reaching close to 300 and 460 Mtpa (35-55 EJ) respectively.
- The use of low-carbon hydrogen in iron and steel production accounts for around 40% of total industrial hydrogen demand by 2050 in *Accelerated* and *Net Zero*, where it acts as an alternative to coal and natural gas as both a reducing agent and a source of energy. The remaining industrial use of hydrogen is in other parts of heavy industry, such as chemicals and cement production, which also require high-temperature heat processes. By 2050, low-carbon hydrogen accounts for around 5-10% of total final energy used in industry in *Accelerated* and *Net Zero*.
- The use of hydrogen within transport is heavily concentrated in the production of hydrogen-derived fuels used to decarbonize long-distance transportation in marine (in the form of ammonia, methanol, and synthetic diesel) and in aviation (in the form of synthetic jet fuel). These hydrogen-derived fuels account for between 10-30% of final aviation energy demand by 2050 and 30-55% of final energy use in the marine sector in *Accelerated* and *Net Zero*. Most of the remainder is used directly in heavy duty road transport. By 2050, low-carbon hydrogen and hydrogen-derived fuels account for between 10-20% of total final energy used by the transport sector in Accelerated and Net Zero.
- The production of some hydrogen derived fuels requires sources of carbon-neutral feedstocks. These can be derived from either biogenic sources or from direct air capture (see pages 78-79).

Low-carbon hydrogen is dominated by green and blue hydrogen, with trade in hydrogen a mix of regional pipelines and global shipping

Global low-carbon hydrogen supply



Sources of EU low-carbon hydrogen



Key points

Low-carbon hydrogen is dominated by a combination of green hydrogen, made via electrolysis using renewable power, and blue hydrogen, made from natural gas (or coal) with the associated carbon emissions captured and stored. Hydrogen trade occurs via regional pipelines or global shipping depending on the form in which the hydrogen is used.

- At present, the cost of producing blue hydrogen is generally lower than for green hydrogen in most parts of the world. However, the combination of recent policy initiatives (such as the Inflation Reduction Act in the US – see pages 36-37) and higher natural gas prices in Europe and Asia as a result of the Russia-Ukraine war (see pages 34-35) has reduced this cost advantage in some countries and regions. This cost differential is further eroded over the outlook as improvements in technology and manufacturing efficiency lower the price of both renewable power and electrolysers.

- As a result, green hydrogen accounts for around 60% of low-carbon hydrogen in 2030 in *Accelerated* and *Net Zero*, with that share increasing to around 65% by 2050. Most of the remaining hydrogen is provided by blue hydrogen, with a small amount produced from bioenergy combined with carbon capture and storage (BECCS). Blue hydrogen acts as an important complement to green hydrogen providing, a lower-cost alternative in some regions as well as providing a source of firm (non-variable) low-carbon hydrogen supply. The growth of blue hydrogen also reduces the extent to which renewable energy is diverted from decarbonizing electricity that is consumed directly.

- The nature of hydrogen trade is likely to vary depending on its final use. For activities and processes that require hydrogen in its pure form – such as for high temperature heat processes in industry or for use in road transport – the gas is likely to be imported via pipelines from regional markets, reflecting the high cost of shipping pure hydrogen. In contrast, for activities that can use hydrogen derivatives, such as ammonia and methanol in marine or hydrogen-derived hot briquetted iron (HBI) in iron and steel manufacturing, the lower cost of shipping these derivatives allows imports from the most cost-advantaged locations globally.

- For example, the EU produces around 70% of the low-carbon hydrogen it uses in 2030 in *Accelerated* and *Net Zero*, with that share falling to around 60% by 2050. Of the low-carbon hydrogen it imports, around half is transported as pure hydrogen via pipeline from North Africa and other European countries (Norway and the UK); and the other half is imported by sea in the form of hydrogen derivatives from global markets.

Carbon mitigation and removals

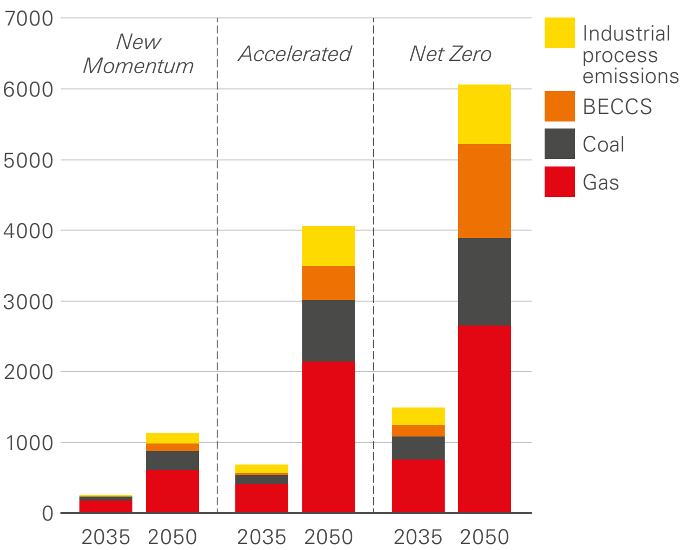
Carbon capture, use and storage plays a central role in enabling deep decarbonization pathways

Carbon dioxide removal is necessary to achieve the Paris climate goals

Carbon capture, use and storage plays a central role in enabling deep decarbonization pathways

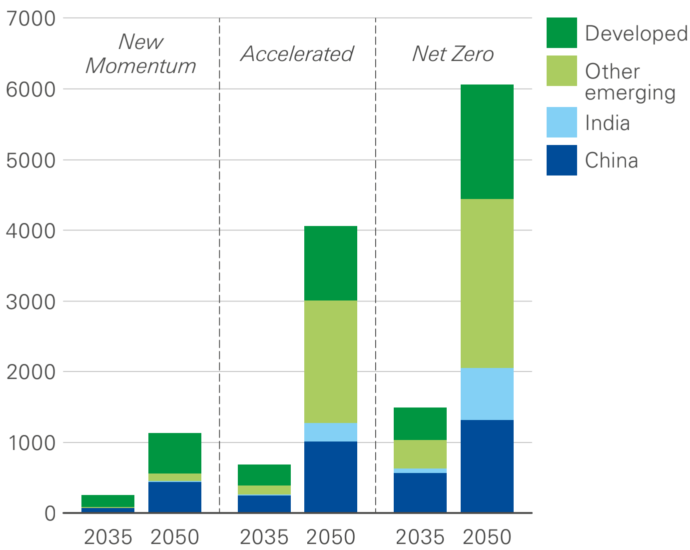
Carbon capture, use and storage by emissions source

Mt CO_2



Carbon capture, use and storage by region

Mt CO_2



Key points

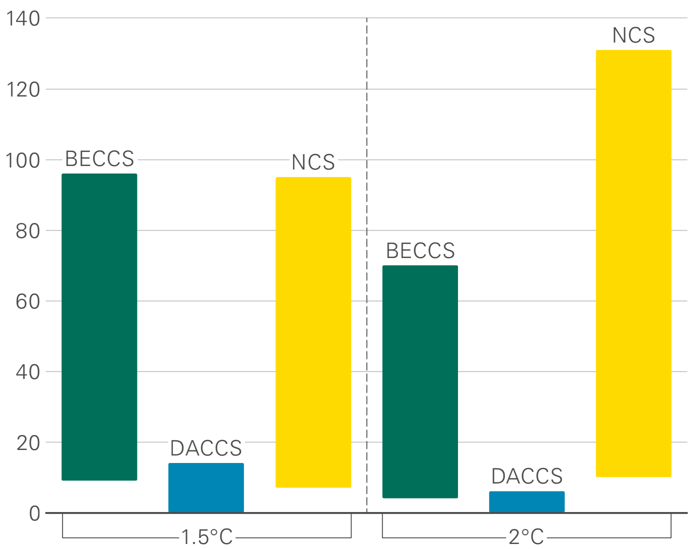
Carbon capture, use and storage plays a central role in supporting the transition to a low-carbon energy system: capturing industrial process emissions, acting as a source of carbon dioxide removal, and abating emissions from the use of fossil fuels.

- Carbon capture, use and storage (CCUS) reaches between 4-6 $GtCO_2$ by 2050 in *Accelerated* and *Net Zero*, compared with 1 $GtCO_2$ in *New Momentum*. The long lead times associated with developing storage sites and their related transport infrastructure means that most of this capacity is completed in the second half of the *Outlook*.
- In all the scenarios, around 15% of the CCUS operating in 2050 is used to capture and store non-energy process emissions from cement production, which has limited decarbonization alternatives.
- The use of CCUS with bioenergy (BECCS) provides both a source of energy and a form of carbon dioxide removal (see pages 78-79). BECCS accounts for around 10% of CCUS in *New Momentum* and *Accelerated* in 2050 and around 20% in *Net Zero*.
- The remaining CCUS is utilized to abate emissions from the use of natural gas and coal.
- In *Accelerated* and *Net Zero*, the deployment of CCUS with natural gas is spread broadly equally across the use of natural gas to produce blue hydrogen (see pages 72-73), to abate emissions in the power sector and to capture emissions from the combustion of gas in industry. The greatest use of CCUS with natural gas occurs in the US, followed by the Middle East, Russia, and China – which combined account for around two-thirds of CCUS deployed with natural gas in 2050 in *Accelerated* and *Net Zero*.
- The vast majority of CCUS with coal is used in regions with relatively new coal-based assets in the power and steel sectors, largely in emerging Asia, led by China.
- In *Accelerated* and *Net Zero*, over 70% of the global deployment of CCUS in 2050 is in emerging economies, led by China and India. This requires a very rapid scale-up of CCUS in these countries relative to their historical levels of oil and gas production, which can be used as an indicator of the geological suitability and engineering capability to develop industrial scale CCUS facilities*.

*Lane et al. (2021): Uncertain storage prospects create a conundrum for carbon capture and storage ambitions

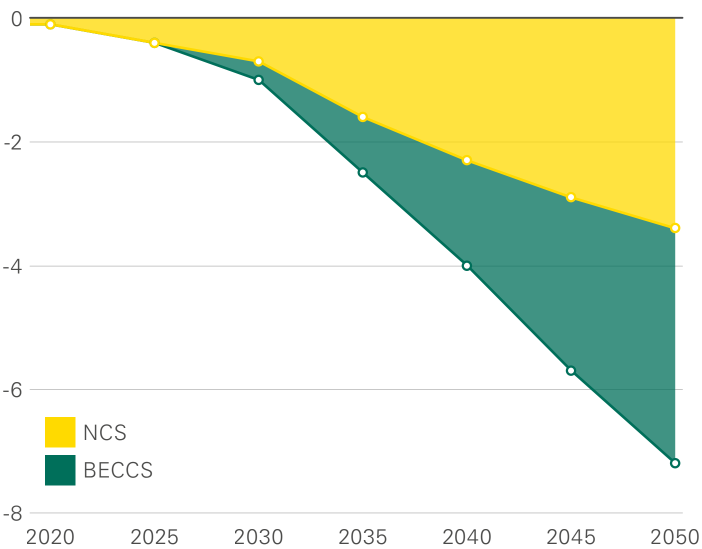
Carbon dioxide removal is necessary to achieve the Paris climate goals

Cumulative carbon dioxide removal in IPCC scenarios: 2015-2050



Maximum and minimum of bars are 10th and 90th percentiles of IPCC scenarios

Annual carbon dioxide removal in median IPCC 1.5°C scenario



Key points

The IPCC, in its Sixth Assessment Report, stated that carbon dioxide removal (CDR) is necessary to counteract hard-to-abate emissions and achieve the Paris climate goals. This includes bioenergy combined with CCUS, natural climate solutions, and direct air carbon capture with storage.

- Bioenergy combined with CCUS (BECCS) has the benefit that it generates useful energy as well as negative carbon emissions. However, the extent to which it can be scaled is limited by the need to ensure the sustainability of the biomass used and by the competition with other priority uses for that biomass.
- Natural climate solutions (NCS) conserve, restore or manage forests, wetlands, grasslands and agricultural lands to increase carbon storage or avoid greenhouse gas emissions. In doing so, NCS can either reduce CO_2 emissions or remove CO_2 already in the atmosphere. NCS can have important co-benefits, such as promoting biodiversity, but can face challenges in ensuring and monitoring their effectiveness and permanence.
- Direct air carbon capture with storage (DACCS) is a process of capturing CO_2 directly from ambient air and then storing it. DACCS has the advantage that it has the potential to be scaled materially, located in the most advantaged regions, and provide considerable certainty on permanence and additionality. However, the current costs of DACCS are high relative to other forms of CDR, reflecting both its relatively low technological maturity and its inherent high energy requirements.
- The uncertainties associated with all forms of CDR means that the IPCC scenarios included in the Sixth Assessment Report include a range of outcomes for the different types of CDR. But all highlight the need for tens to hundreds of gigatons cumulatively out to 2050.
- The median IPCC 1.5°C scenario includes a rapid scale-up of both NCS and BECCS, reaching over 7 $GtCO_2$ per annum by 2050. The pace at which these forms of CDR grow means they help to accelerate the pace of decarbonization over coming decades, as well as offset hard-to-abate emissions in a net zero system.
- Although few of the modelled pathways included in the IPCC's Sixth Assessment Report embody a material role for DACCS, more recent analysis by the IEA and the Energy Transitions Commission* envisage a larger role for it.

Synthetic fuel CO_2 feedstock requirement

- The production of some hydrogen-derived fuels - primarily synthetic jet fuel, but also synthetic diesel and methanol (see pages 42-43) – require a carbon-neutral feedstock. This can be sourced from either bioenergy with carbon capture or direct air capture. Although the source is not explicitly modelled in the *Outlook*, the CO_2 requirement for hydrogen-derived fuels by 2050 is around 200 and 500 Mtpa for *Accelerated* and *Net Zero*, respectively.

*International Energy Agency, World Energy Outlook 2022; Energy Transitions Commission, Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonization to Keep 1.5°C Alive, March 2022

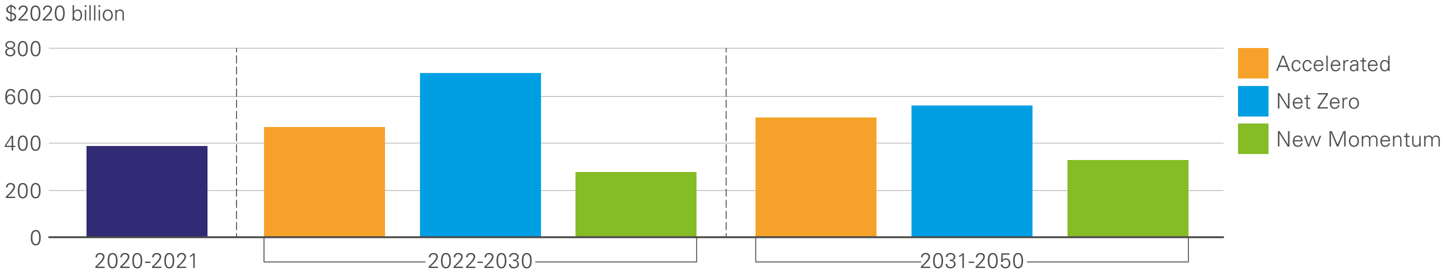
Investment and critical minerals

Investment in wind and solar capacity increases sharply and continues in oil and natural gas

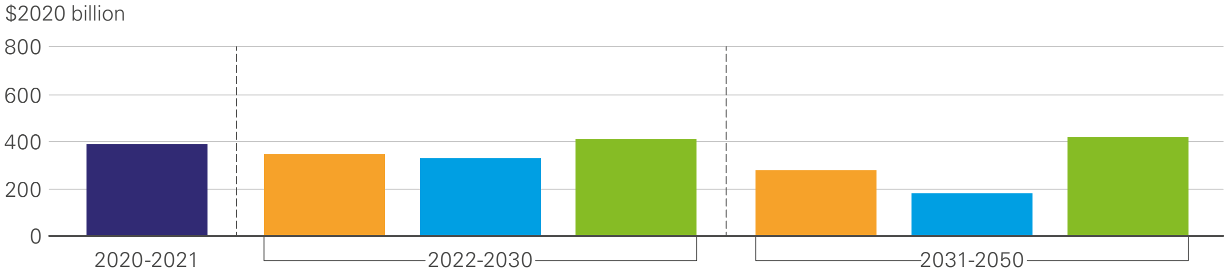
The energy transition leads to a significant increase in the demand for critical minerals

Investment in wind and solar capacity increases sharply and continues in oil and natural gas

Average annual investment in wind and solar



Average annual investment in upstream oil and gas



Key points

The energy transition requires substantial levels of investment across a wide range of energy value chains. The implied level of investment in wind and solar capacity accelerates markedly from recent levels. Despite declining levels of demand, continuing investment in upstream oil and natural gas is also required.

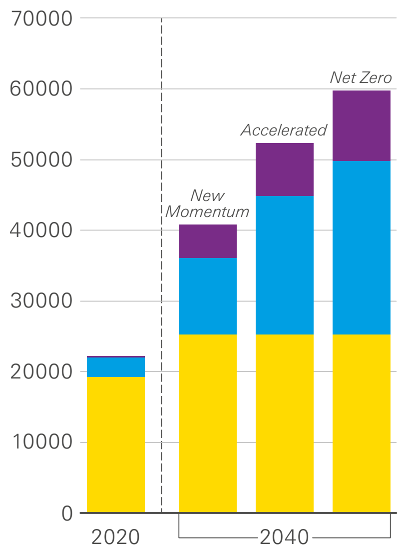
- The investment estimates considered here refer to investments in wind and solar capacity and in upstream oil and gas production. The assumptions underlying the implied investment requirements, and the associated uncertainties, are described in the Annex (see pages 120-121).
- The energy pathways envisaged by the three scenarios also require substantial investment in other types of assets not included in these estimates, such as electricity distribution and transmission networks, pipelines for transporting low-carbon hydrogen and CO_2, and new facilities for producing bio- and hydrogen-based fuels.
- The central role that wind and solar energy play in the production of low-carbon electricity requires a substantial acceleration in the investment in new capacity. In *Accelerated* and *Net Zero*, the average level of annual investment over the rest of this decade is between 20-80% higher than recent levels. The falling cost of wind and solar energy (see pages 56-57) means that investment expenditure in *New Momentum* out to 2030 is lower than recent levels whilst maintaining a similar pace of increase in new capacity deployed; investment spending scales up in the second half of the outlook as deployment accelerates.
- In *Accelerated* and *Net Zero*, around 70% of the investment in new wind and solar capacity over the outlook occurs in emerging economies. This underlines the importance that renewable developers in these economies have good access to capital and finance.
- Although the demand for oil and gas falls in all three scenarios, natural base decline in existing production means that continuing investment in upstream oil and natural gas assets is required in all three scenarios to meet future demand. This includes investment across a range of different types of supply (brownfield, greenfield, and tight oil and natural gas). The uncertainty surrounding the prospects for future oil and natural gas demand means shorter-cycle and phased production opportunities with greater optionality become increasingly important over time.
- The implied rates of investment in upstream oil and gas in the second half of the outlook, especially in *Accelerated* and *Net Zero*, are lower than levels in the recent past and significantly less than the required investment in wind and solar capacity.
- The average annual investment in upstream oil and natural gas over the rest of this decade in the three scenarios is between $325-$405 billion, compared with $395 billion in the recent past*.

*Upstream oil and gas investment includes capital expenditures on wells construction, facilities and exploration. It does not include operational expenditures.

The energy transition leads to a significant increase in the demand for critical minerals

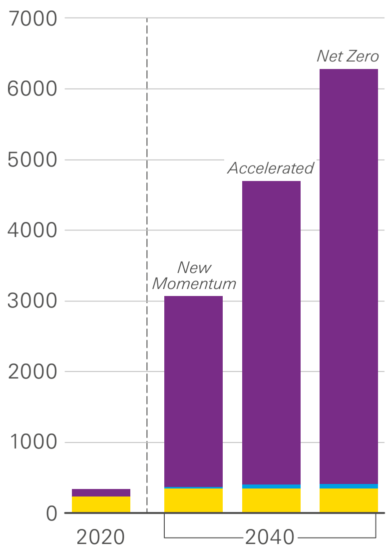
Copper demand

kt



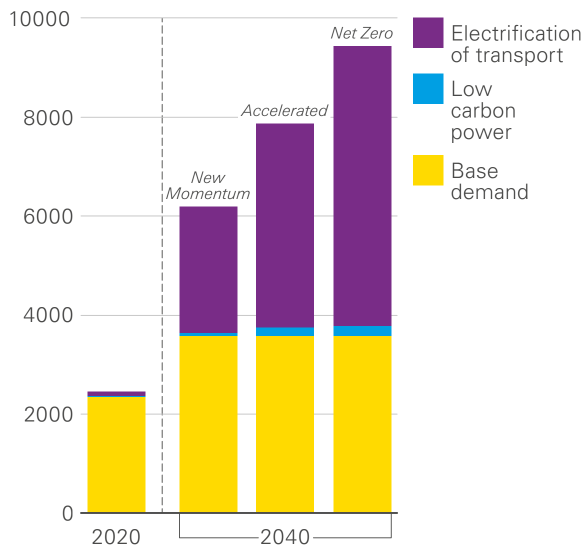
Lithium demand

kt, Lithium carbonate equivalent



Nickel demand

kt



Key points

The shift to a low-carbon energy system requires a substantial increase in the use of a range of minerals critical for the infrastructure and equipment supporting this transition.

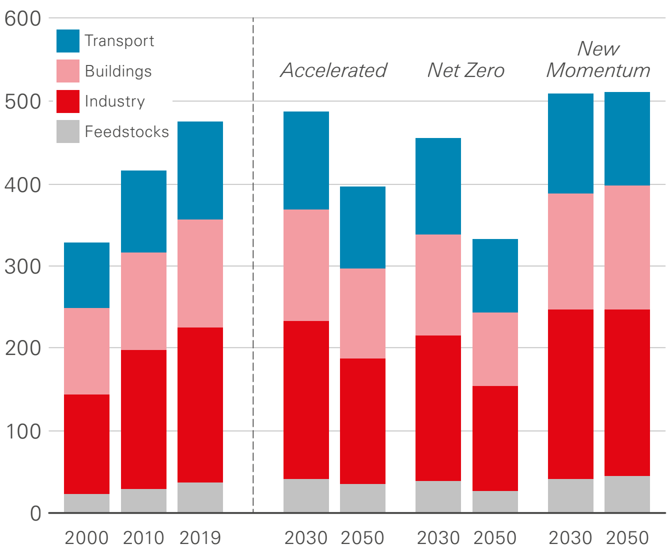
- The increasing demands for minerals and materials associated with the energy transition come from across the low-carbon energy system, including the construction of wind and solar facilities, batteries, hydrogen and CO_2 pipelines, and new storage facilities. Two particularly important sources of demand in this year's *Outlook* stem from:
- Growth in low-carbon power requiring a substantial expansion in the grid and distribution systems used to connect renewable assets and deliver electricity to its end use.
- Electrification of road transport leading to a global car parc of between 1-2 billion electric vehicles by 2050, implying an increased demand for annual battery capacity within road transport of between 10-20 TWh.
- The growing requirements associated with the energy transition, along with the broader economic expansion envisaged over the outlook, have important implications for a range of minerals critical for the transition. Below we look at just three: copper, lithium, and nickel.
- Copper: The future growth of copper is dominated by its use in the construction of new electricity networks for low-carbon power, which increases between four- and seven-fold out to 2040 in the three scenarios. Total copper demand grows between two and three times over this period: 65-85% of the growth is due to the increasing demand for copper to support the transmission of low-carbon power and the electrification of transport. As a result, the use of copper within low-carbon energy activities and electrification of transport accounts for around a half of total copper demand in 2040 in *Accelerated* and *Net Zero* compared with around 15% in 2020.
- Lithium: The growing demand for lithium over the outlook is driven by its use in electric vehicles, which grows by a factor of between 25 and 60 out to 2040 across the three scenarios. This use accounts for 85-95% of the aggregate demand for lithium in 2040, compared with 30% in 2020.
- *Nickel:* Increasing demand for nickel is also driven by its role in the electrification of transport. Total nickel demand increases between 2.5-4 times out to 2040 across the three scenarios – 65-80% of that growth is due to the increasing use of lithium-ion batteries in electric vehicles.
- The scenarios assume that the supply of critical minerals scales to meet these increasing demands. This requires a significant increase in investment and resources within the critical minerals mining sector, as well as an acceleration in planning and permitting lead times. The challenge associated with this scaling up is compounded by the need to maintain close scrutiny on the sustainability of new and existing mining activity.

How energy is used

Energy demand peaks in all sectors as energy efficiency gains accelerate

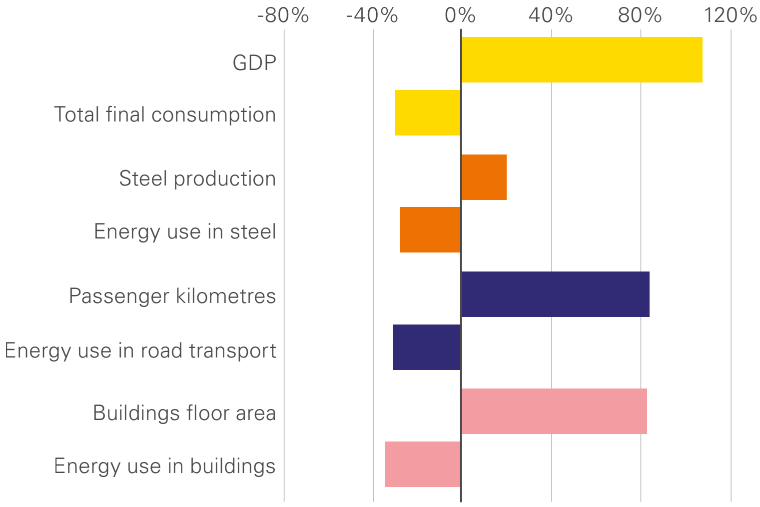
Final energy demand by sector

EJ



Growth in energy usage and drivers in *Net Zero*

% growth 2019-2050



Key points

Global energy demand peaks before or by 2050 for all end-use sectors over the *Outlook* as energy efficiency gains accelerate. This reflects increased energy conservation measures, increasing material recycling and the replacement of existing appliances, vehicles and process plants with more efficient technology.

- Three key sectors make up energy demand, as measured at the final point of use (total final consumption, or TFC) – transport, buildings and industry, which in its widest sense, includes fuel used as a feedstock. Energy use in industry and feedstocks together account for almost half of end-use consumption today, with transport and buildings making up roughly equal shares of the rest.

- Energy consumption in all sectors peaks by 2030 in *Accelerated* and *Net Zero*, with TFC 15-30% below 2019 levels by 2050. In contrast, TFC increases until around 2040 in *New Momentum*, after which it broadly plateaus with energy consumption in 2050 around 10% above 2019 levels.

- The main factor driving these differences in TFC is the pace of improvement in energy efficiency. To illustrate this at the aggregate level, TFC in *Net Zero* falls by 30% between 2019 and 2050 despite economic activity (GDP) more than doubling. This implies average annual gains in energy efficiency (or annual reductions in energy intensity, the energy required for one unit of GDP) of 3.4% per year, roughly double the pace over the past 20 years or so (1.8% per year). There are several examples at the sector level illustrating how this efficiency gain in *Net Zero* is achieved:

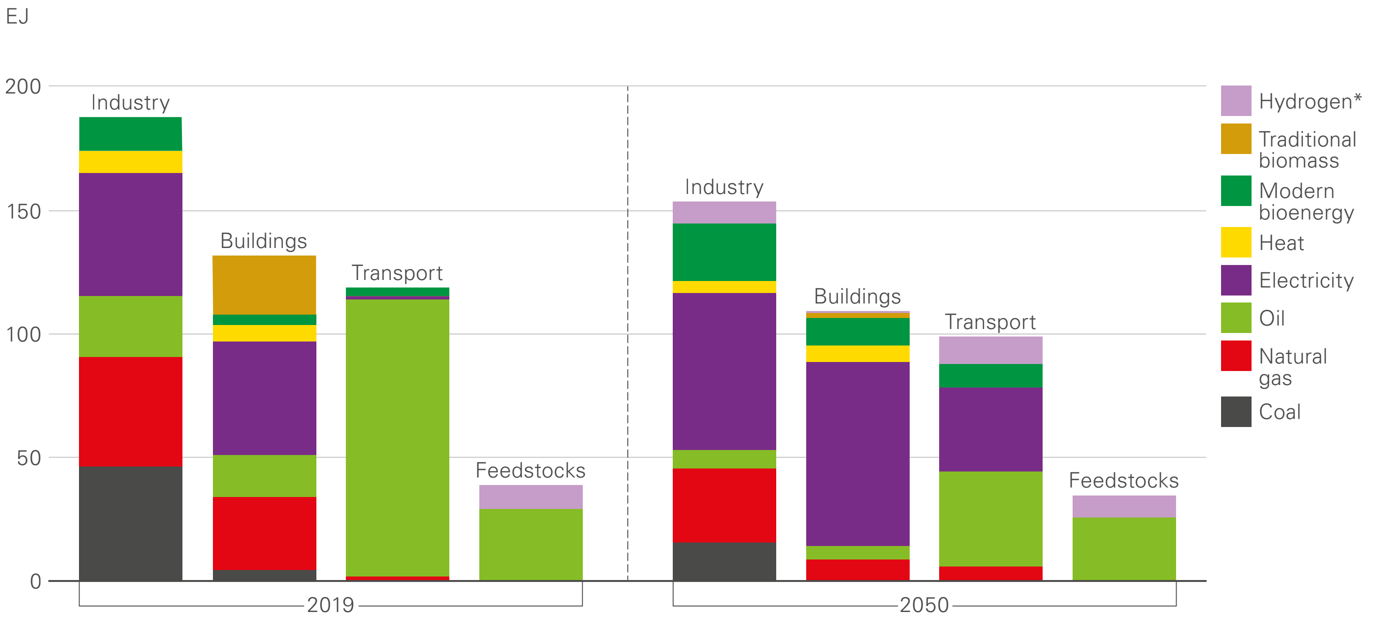
  - Within industry, energy use in steel making declines by around 25% by 2050 despite a 20% increase in steel production. That is due to the gradual replacement of energy intensive blast furnaces by more efficient plants (such as Direct Reduced Iron (DRI) units) and an increase in the recycling of scrap, which can produce steel using a quarter of the energy used to convert iron ore.

  - In transport, road passenger kilometres driven (Pkm) increase by 84% to 2050, led by rising prosperity, particularly in the emerging economies. Growth in total vehicle kilometres is higher (113%), as autonomous vehicles are projected to add vehicle kilometres from repositioning to provide mobility services. Energy demand in road transport over the same period shrinks by 10-30% across the scenarios as internal combustion engine (ICE) cars and trucks are replaced by more efficient ICE models and electric vehicles (EVs) (see pages 104–107).

  - Total buildings floor area is projected to increase by more than 80% by 2050, but energy used across this larger building stock falls by one third relative to 2019. The fall is due to a range of different energy conservation measures including better insulation and improved appliance efficiency. The largest drivers of energy efficiency gains are the displacement of fossil fuel (mainly gas) boilers with electric heat pumps, and the substitution of inefficient traditional biomass for cooking with other fuels.

Energy gradually electrifies, together with an increasing role for hydrogen and bioenergy in hard-to-abate sectors

Final energy demand by sector and fuel in *Accelerated*



*Includes hydrogen-derived fuels

Key points

The share of electricity in TFC rises in all scenarios and in all sectors.

The greatest overall scope for electrification is in buildings, while transport has the largest increase in share, given current low levels (see page 62).

In some sub-sectors within transport and industry (so-called hard-to-abate sectors) electrification is more difficult, leading to an important role for low-carbon hydrogen and bioenergy in decarbonization.

- The fuel mix of the main end-use sectors varies substantially today. While transport and industrial feedstocks rely heavily on oil, energy demand in other sectors is more diverse, with a mix of oil, gas, electricity, biomass (particularly traditional biomass for buildings in some emerging markets) and coal (particularly for use in heavy industry).

- In all three scenarios there are common trends in the changing fuel mix. Across all end-use sectors, the use of fossil fuels declines and the share of electricity increases significantly (also discussed in pp62-63 of the Energy Outlook), with growing shares of low-carbon hydrogen and modern bioenergy also helping to decarbonize the energy mix.

- The transport sector has the largest increase in the share of electrification relative to its current low level, largely reflecting the electrification of road transport (see pages 104–107). In the harder-to-abate sectors within transport there is also a role for biofuels, low-carbon hydrogen – particularly in heavy road transport – and hydrogen-derived fuels (such as methanol, ammonia and synthetic kerosene) in marine and aviation.

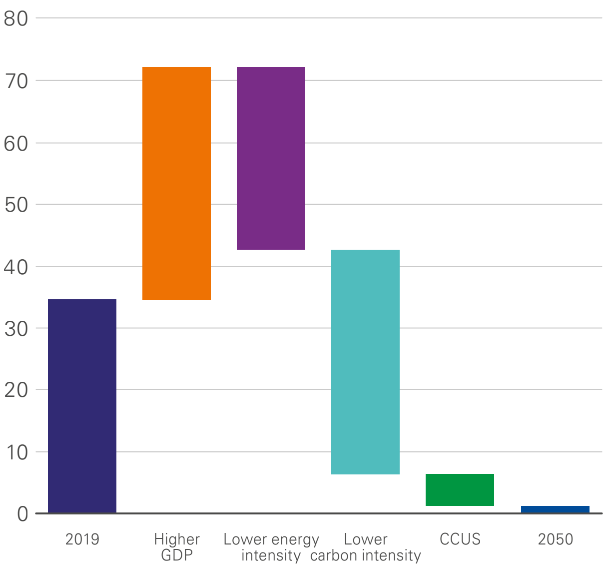
- The greatest scope for electrification is in buildings where at least half of final energy demand is electrified in all three scenarios, driven by strong growth in the demand for air-conditioning and, particularly in *Accelerated* and *Net Zero*, the adoption of heat pumps. Rising prosperity in emerging economies also leads to a reduction in the use of traditional biomass for cooking and heating, displaced by liquid petroleum gas (LPG), natural gas, modern biomass and, increasingly over the Outlook, electricity. There is only a limited role for hydrogen in buildings.

- Industry also sees a rise in its share of electricity but this is more limited, particularly for processes requiring high temperatures (>200°C). That leads to a significant role for low-carbon hydrogen and bioenergy as a source of low-carbon heat, particularly in *Accelerated* and *Net Zero*. Low-carbon hydrogen also displaces the grey (natural-gas-derived) and brown (coal-derived) hydrogen produced today for use as a feedstock. By 2050, hydrogen accounts for between 5% and 15% of energy across industry and feedstocks.

- Due to the cost of shifting to other fuels in some hard-to-abate industrial processes (such as iron and steel, cement and petrochemicals) there is still a sizeable role for natural gas and coal in industry in 2050, some of which is abated by carbon capture usage and storage (CCUS) – 20% in *Accelerated* and over 60% in *Net Zero*.

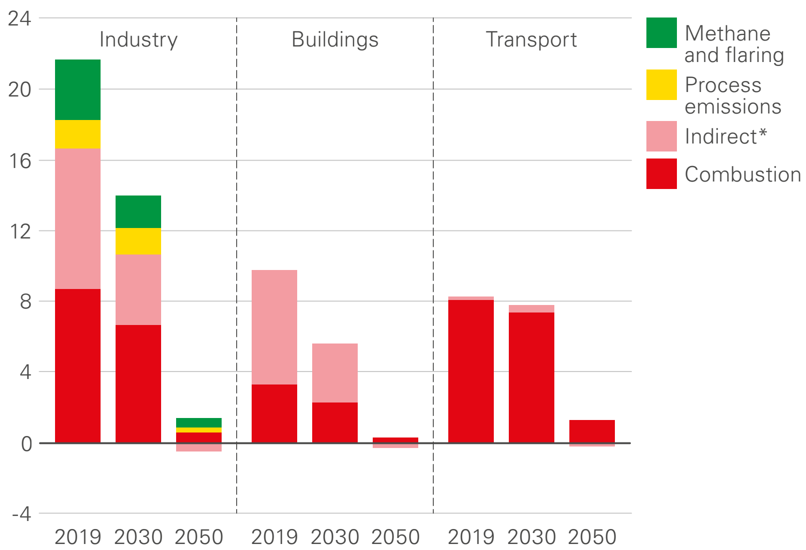
Carbon emissions driven lower by energy efficiency gains and changes in the fuel mix

Drivers of changes in CO_2 emissions from energy use in *Net Zero* (2019-2050)



CO_2 from combustion, not including flaring, methane emissions or process emissions

Total carbon emissions by sector in *Net Zero*



*Emissions from electricity, heat networks and hydrogen production allocated based on consumption of these in each end-use sector

Key points

Energy efficiency gains and the shift in the end-use fuel mix are key to reducing carbon emissions over the Outlook. The decarbonization of electricity used is also important and is the main driver for reductions in the first part of the outlook.

- Both energy efficiency and the changing fuel mix are key to the reduction in carbon emissions over the Outlook. For example, in *Net Zero*, improvements in energy efficiency, measured by the reduction in energy intensity almost offsets the impact from rising GDP, which more than doubles over the Outlook. Improvements in carbon intensity are delivered through decarbonizing the power sector and switching to lower carbon fuels which together bring a similar reduction in emissions, with CCUS helping to approach net zero emissions in 2050.

- By sector, more than half of carbon emissions today are associated with industry. That is due to it being the largest sector in terms of energy consumption, and other factors including its relatively heavy use of coal (which has a higher carbon intensity than oil or gas), process CO_2 emissions that come from cement production, and methane emissions and flaring associated with oil and gas production.

- Emissions associated with buildings and transport today are roughly equal, although more than half of buildings emissions are 'indirect', stemming from the fossil fuels used to produce the electricity used in buildings.

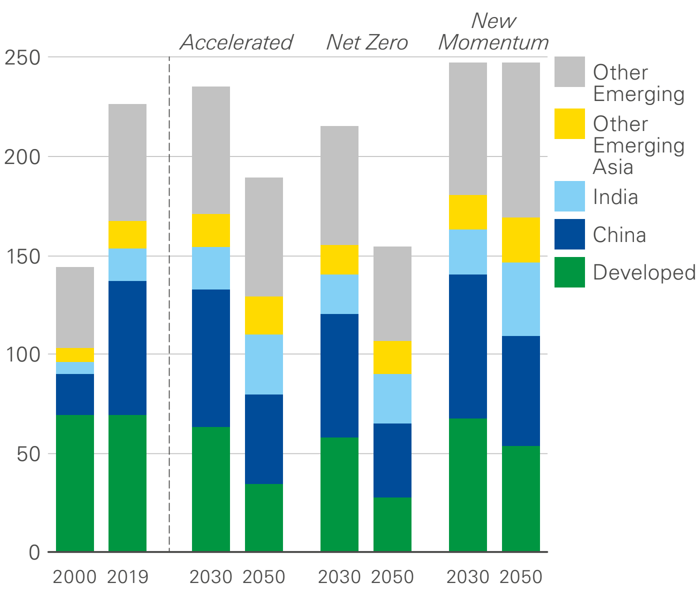
- Much of the reduction in carbon emissions by 2030 is due to the decarbonization of the power sector (see pages 64-65), which reduces indirect emissions in industry and buildings in particular. Electrification of demand amplifies this effect as well as also reducing direct emissions as fossil fuel use is reduced.

- Both direct and indirect emissions reductions then accelerate, leading to close to a 30% drop in total carbon emissions by 2050 in *New Momentum*.

- In *Accelerated* and *Net Zero*, nearly all indirect emissions have been eliminated in all three sectors by 2050 as the power sector and other secondary forms of energy such as hydrogen and commercial heat are nearly carbon-free. The remaining direct emissions are concentrated in the hard-to-abate sub-sectors within industry and transport, such as cement, iron and steel, marine and aviation.

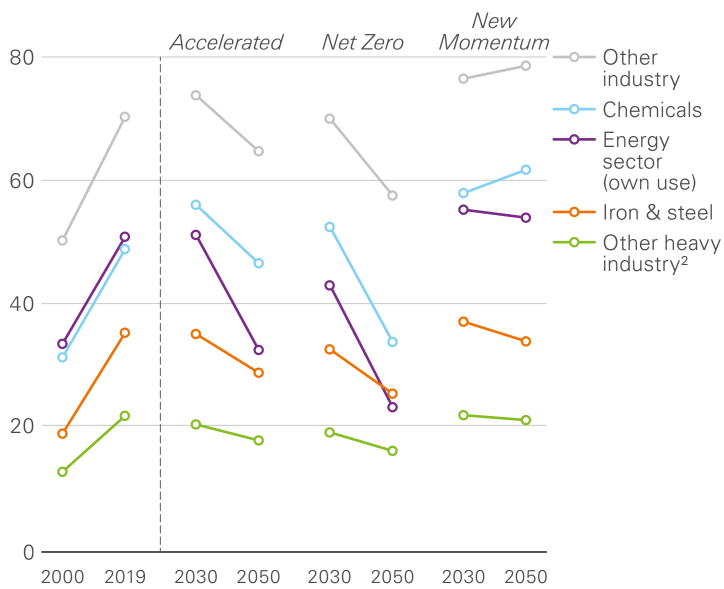
Energy demand in industry peaks despite continued growth in India and other emerging Asian economies

Industry[1] final energy demand by region



[1]Includes feedstocks

Industry[1] final energy demand by sector



[2]Non-ferrous metals and non-metallic minerals

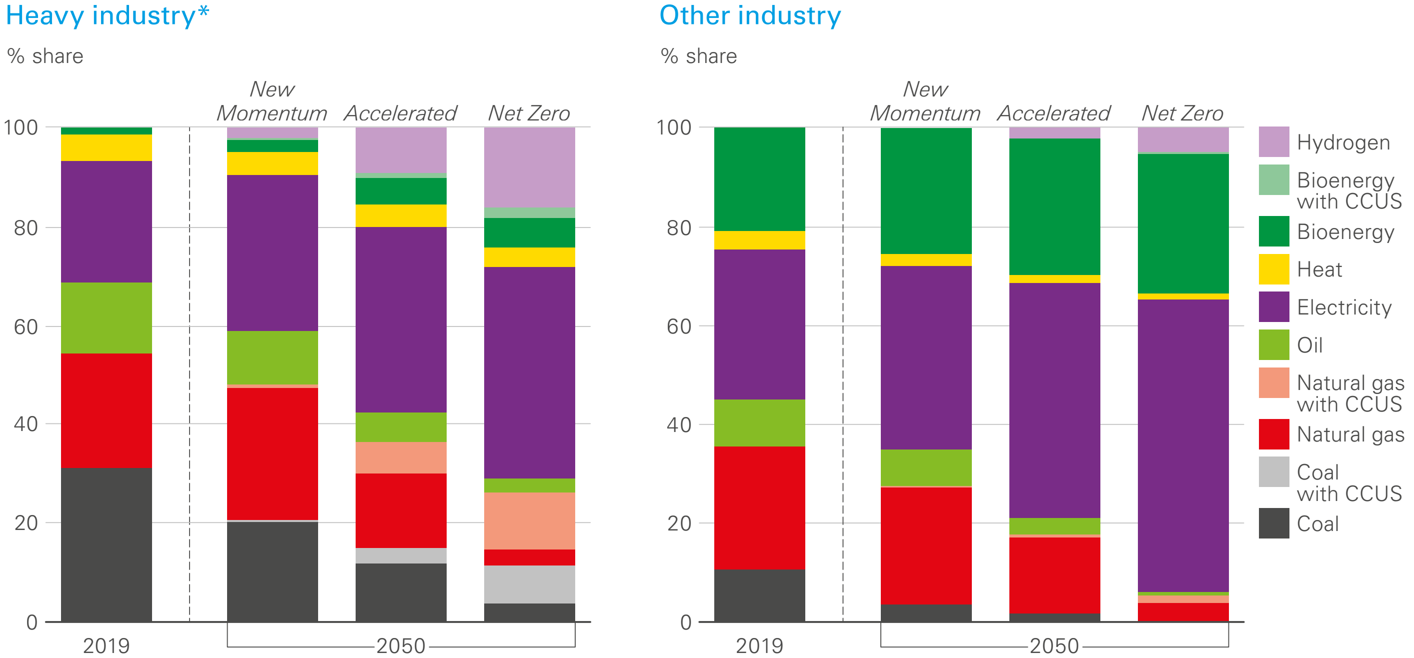
Key points

Energy demand in industry falls over the second half of the Outlook as China's energy demand declines, outweighing growth in India and other emerging Asian countries. The decline in demand is particularly pronounced in the energy and chemicals sub-sectors in *Accelerated* and *Net Zero* due to increasing societal and political pressure on the use of oil products and plastics.

- Over the past 20 years or so China has seen rapid growth in industrial output and its associated energy use. China is now the largest producer of steel, cement, and most key petrochemicals, and its energy use in industry made up 30% of global industrial energy demand in 2019, almost as much as in all developed economies combined. China has accounted for around 60% of the growth in energy use in industry since 2000.
- However, China's industrial energy demand peaks around 2030 in all scenarios and declines significantly by 2050 as its economy becomes more services-orientated and production shifts to less developed economies. India and other emerging Asian economies become the main regions of industrial growth, with their combined share of energy rising from 13% in 2019 to 18-26% by 2050. Nevertheless, improvements in industrial efficiency (see pages 88-89), causes global energy demand in industry to peak in all scenarios and to decline in the second half of the outlook.
- Industrial energy use in developed economies peaked in 2000 and continues to decline over the Outlook, driven both by energy efficiency gains and declining output in energy intensive industries.
- Industry comprises hundreds of distinct processes for producing goods and materials. The largest individual contributors to energy demand are iron and steel, chemicals (including petrochemicals) and the energy industry itself, due to the energy use and losses associated with fuel production.
- These sub-sectors, combined with non-ferrous metals and non-metallic minerals (such as cement), make up what we refer to as heavy industry, which is characterised by large process plants that require high-temperature heat. The remaining industrial sectors, defined here as 'Other industry', are a collection of mainly manufacturing processes, such as food, paper and textiles.
- Energy demand falls post-2030 in most sub-sectors across the three scenarios, driven both by process energy efficiency and material efficiency, which includes increased recycling and measures to reduce materials demand. These falls are particularly pronounced for the energy and chemicals sectors in *Accelerated* and *Net Zero* due to increasing societal and political pressures to reduce the use of oil products and plastics.
- The exceptions to these declines in energy demand are chemicals and other industry in *New Momentum*, where efficiency measures are outpaced by continued growth in demand for consumer goods as incomes increase.

Industry electrifies, with hydrogen and CCUS helping to decarbonize heavy industry

Mix of fuels in final energy demand by scenario



*Iron & steel, non-ferrous metals, non-metallic minerals, chemicals (excluding feedstocks), and energy own use & losses

Key points

As with other sectors, industry gradually electrifies but at a slower rate due to the difficulty of electrifying high-temperature heat in heavy industry. To decarbonize, heavy industry increases its share of low-carbon hydrogen and bioenergy, and abates remaining fossil fuel use with CCUS. Other industry shifts mainly towards electricity and bioenergy.

- Heavy industry is a grouping of energy intensive processes such as the production of steel and other metals, non-metallic minerals such as cement, petrochemicals, and oil and gas. These processes all require high-temperature heat (more than 200°C) which is difficult to electrify. Today they mainly use fossil fuels – particularly coal for cement and iron and steel (where the coal also acts as a reducing agent) and natural gas, which is used mainly in petrochemicals and the oil and gas industry.

- Other industry consumption is currently dominated by electricity for motors, mechanical processes and low-temperature heat, natural gas for use in boilers and – where available – biomass (particularly in the food and paper industries).

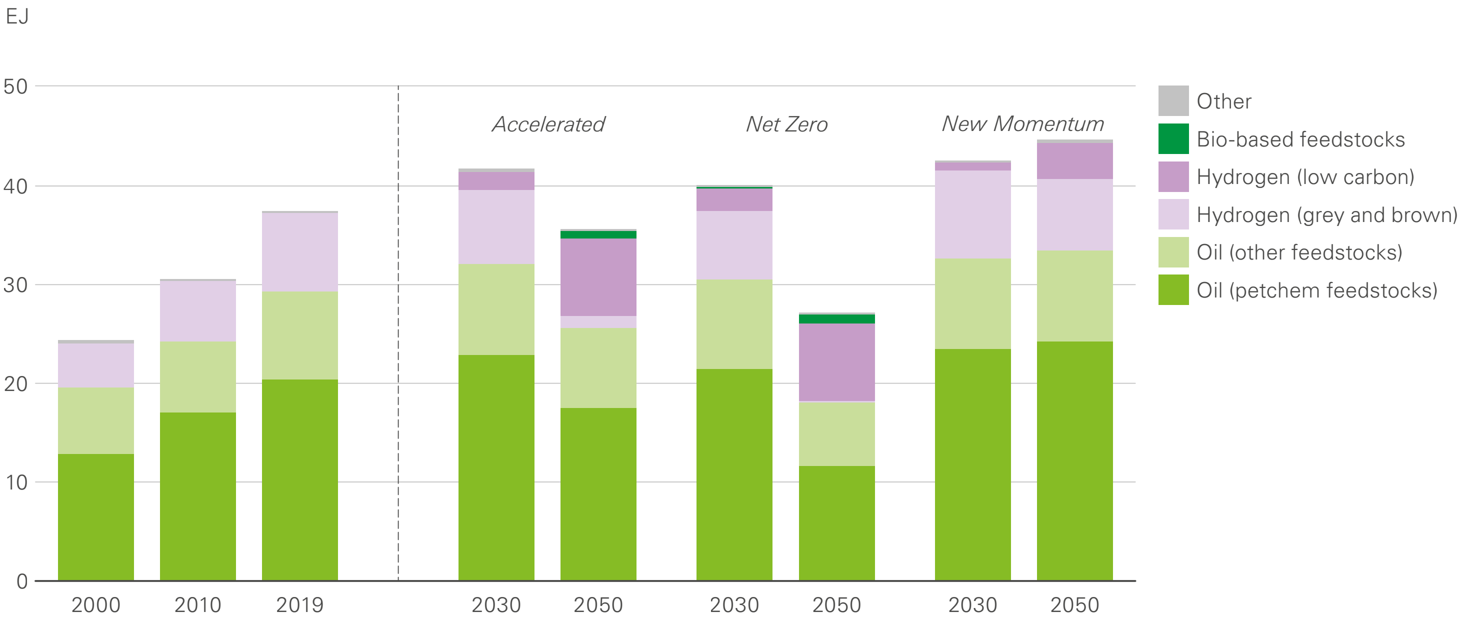
- Within heavy industry, in all scenarios the share of electricity increases while the shares of coal and oil decline. The share of natural gas remains roughly constant in *New Momentum* and *Accelerated*, but declines in *Net Zero*, with most of the remaining consumption abated with CCUS. In *Accelerated* and *Net Zero* there is significant growth in the use of low-carbon hydrogen and bioenergy, given the limitations in electrifying high-temperature processes.

- Iron and steel accounts for the largest use of low-carbon hydrogen in industry (not including feedstocks) where it is used both as an energy source and as a reducing agent in the process of reducing iron ore to iron. This is clearest in *New Momentum*, where more than 75% of industrial hydrogen demand is in the iron & steel sector. In *Accelerated* and *Net Zero*, the share is around 40%, with the other 60% used to provide high-temperature heat in other sectors, for example in petrochemicals, glass, ceramics and cement.

- In other industry there is greater scope for electrification than in heavy industry, with technologies such as industrial-scale heat pumps capable of producing the lower temperature heat required. In *Net Zero*, the energy mix for other industry is dominated by electricity (~60% share) by 2050, with bioenergy most of the remainder (~30%).

Demand for feedstock grows over the medium term but peaks as pressure on the use of plastics increases

Use of feedstocks by fuel and scenario



Key points

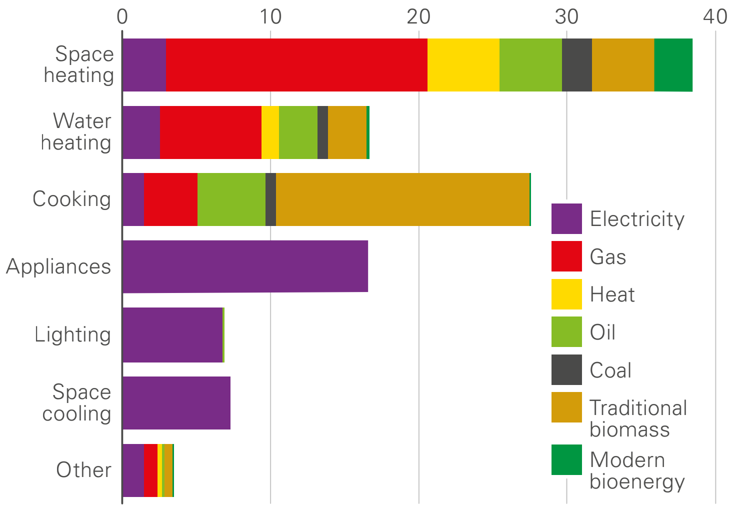
Consumption of fuels used as feedstock grows until the mid-2040s in *New Momentum*. This is driven by demand for plastics and hydrogen used in refining and the production of fertiliser and petrochemicals. In *Accelerated* and *Net Zero*, demand declines post-2030 due to actions to limit the use of plastics.

- Fuel use as a feedstock today can be broadly split into three categories:
  - oil-based petrochemicals, predominately for plastics, which make up the largest share (55% in energy terms).
  - oil used to make other materials like bitumen, lubricants and solvents.
  - grey (gas-based) and brown (coal-based) hydrogen used in oil refining, the production of ammonia for fertilizer and petrochemicals, and the production of methanol (used mainly for petrochemicals, but also in road fuels).
- Demand for feedstock has grown strongly since 2000 (2.3% per year from 2000-2019) and continues to grow until the mid-2040s in *New Momentum*. In *Accelerated* and *Net Zero* demand declines post-2030, driven by falling demand for virgin plastics due to measures that limit the use of single-use plastics and incentivise higher recycling rates.
- There is some displacement of oil by bio-based feedstocks in the second half of the Outlook – particularly in ethanol-producing regions, such as the US and Brazil – and by low-carbon hydrogen. Low-carbon hydrogen can be used to produce e-naphtha, a direct replacement for oil-based petrochemical feedstock, and e-methanol, which can be used as the building block for plastics via the methanol-to-olefins process.
- There could be potential for more bioenergy to be used as a substitute for oil-based petrochemical feedstocks, but there are limits to the amount of bioenergy that can be supplied on a sustainable basis, and other sectors such as aviation take the bulk of the available supplies in all three scenarios.
- Demand for feedstock hydrogen varies across scenarios. In *New Momentum*, demand increases by 35% between 2019 and 2050, driven by growth in fertiliser use and methanol demand for traditional uses. Demand from refining declines slightly as refinery output falls.
- In *Net Zero*, hydrogen demand in refining declines significantly, as does the use of methanol in road fuels. However, this is more or less offset by new uses of hydrogen to displace oil-based petrochemicals, such that demand in 2050 is close to 2019 levels.
- Grey and brown feedstock hydrogen is gradually replaced by low-carbon hydrogen, but at very different speeds across scenarios. Around 5-25% of feedstock hydrogen is decarbonized by 2030, and between 35% and nearly 100% by 2050.

Energy demand in buildings is dominated by heating and cooking requirements.

Energy demand by service and fuel (2019)*

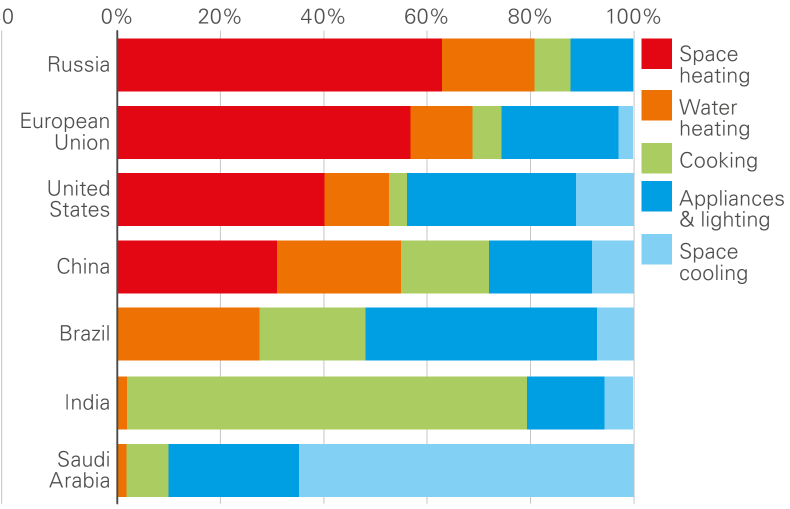
EJ



*Excludes solar thermal

Energy demand by service in key countries and regions (2019)

% share



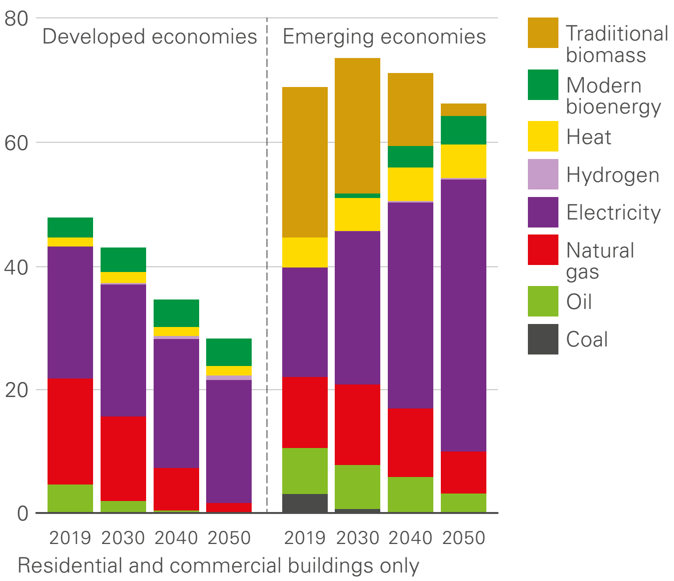
Key points

Heating accounts for around 50% of the energy used in buildings today, with natural gas the most commonly used fuel. Cooking accounts for 25% of the energy used, dominated by the inefficient use of traditional biomass in emerging economies.

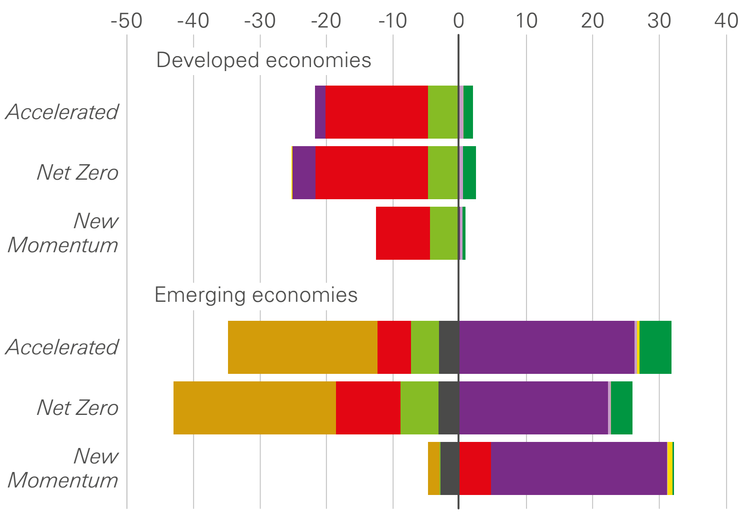
- The largest requirement for energy in residential and commercial buildings globally is for space and water heating, which combined make up almost 50% of the energy used in buildings. Energy for cooking makes up another 25%, with the rest largely electricity used for appliances, lighting and space cooling.
- Natural gas is the most widely used fuel for space and water heating, making up 44% of the mix in 2019, around four times more than other alternatives – electricity, oil, district heating and traditional biomass all have shares of roughly 10%.
- Total energy demand for cooking is currently dominated by the use of traditional biomass in developing economies (62%), due to the inefficiency of its use in traditional stoves (which are roughly five times less efficient that natural gas stoves, for example). Oil, usually in the form of LPG or kerosene, and natural gas are also commonly used fuels.
- The services required in buildings vary significantly by region due to differences in weather. For example, in Russia and the EU, around 60% of energy in buildings is required for space heating, while in warmer climates there is little or no space-heating demand.
- Within the warmer regions there are also differences due to income, with low-income countries such as India using the majority of their energy in buildings for cooking (due to their reliance on inefficient traditional biomass) while higher-income countries, such as Saudi Arabia, use most energy for space cooling.
- At a global level, space cooling makes up only 6% of energy demand in buildings. This is because of low ownership of air-conditioners in many of the world's warmest regions due to low incomes. As incomes increase over the Outlook in these regions, the number of households with space cooling rises rapidly, adding to the growth in electricity demand.

Buildings energy use electrifies while efficiency improves in all regions

Consumption by fuel in *Accelerated*



Changes in consumption by fuel (2019-2050)



Key points

Growth in energy demand in buildings slows as space heating and cooking appliances become more efficient and energy conservation increases. The share of electricity in the energy mix rises as fossil fuel boilers are replaced by heat pumps, and rising incomes in the emerging economies leads to increased use of air-conditioning and the phasing out of traditional biomass.

- Energy use in buildings in developed economies declines in all scenarios due to increasing energy efficiency. This is largely due to a range of different energy conservation measures (insulation, smart meters, resident behaviours) and more efficient appliances (including heating and cooling systems). The increased use of solar thermal and waste heat via heat networks also reduces the requirement for other energy sources but was not modelled explicitly in our scenarios.

- The fuel mix in developed regions gradually electrifies, driven largely by the displacement of gas boilers by heat pumps, although the share of heat from district heat networks and modern bioenergy (biomethane and biomass such as wood pellets) also rises in all scenarios. There is only a limited role for hydrogen.

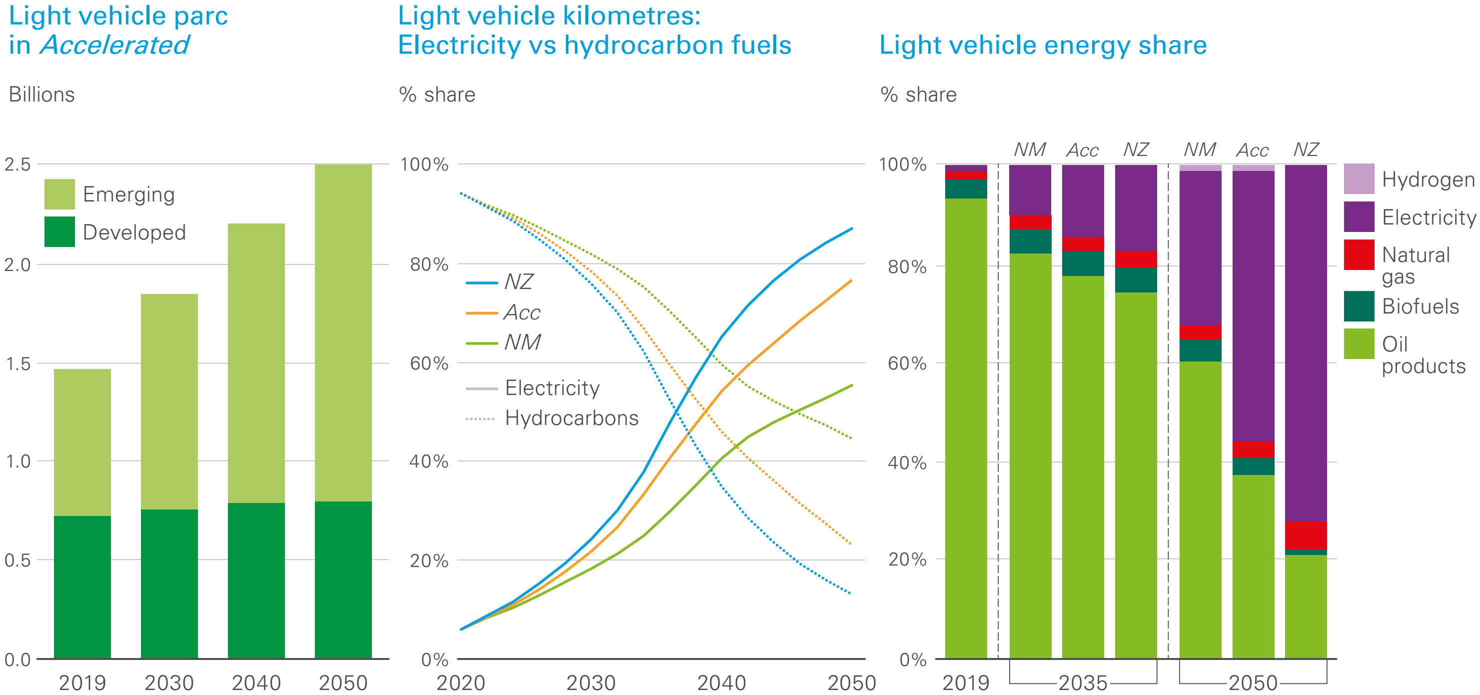
- Due to the efficient nature of heat pumps, with roughly one unit of electricity displacing three units of gas, as the share of electricity in the energy mix rises, total energy demand for heating falls. These declines are amplified by additional energy conservation measures, resulting in no absolute increase in electricity demand in developed economies in all three scenarios despite the large increase in electricity's share. The largest decline in energy terms is for natural gas demand, which falls substantially in all scenarios by 2050.

- In emerging economies, energy demand in buildings peaks between 2025 and 2035 in *Accelerated* and *Net Zero* driven by the phasing out of inefficient traditional biomass, with roughly one joule (J) of LPG, natural gas, modern bioenergy or electricity displacing between 4J and 8J of traditional biomass.

- This effect masks the strong growth in modern energy demand across all scenarios as rising incomes boost growth in electricity for appliances, lighting and air-conditioning. Emerging economies' energy demand excluding traditional biomass grows 15-65% between 2019 and 2050 (~15% for *Net Zero* and 65% in *New Momentum*).

- There is a transitional role for LPG and natural gas as an alternative to traditional biomass over the next few years, with gas demand in the emerging economies peaking around 2030 in *Accelerated*. But as climate pressures rise later in the Outlook, the remaining fossil fuels are gradually substituted with electricity, modern bioenergy, solar thermal and district heating as in developed economies.

As activity grows, electricity increasingly replaces oil products as the main energy carrier for light vehicles



*Scenario abbreviations: NM (New Momentum), Acc (Accelerated), NZ (Net Zero)

Key points

In all three scenarios, two important trends are underway for light-duty road transportation. First, increasing prosperity brings increased levels of vehicle ownership, with a larger parc of vehicles driving more kilometres. Second, regulation and technological advances spur a shift from oil products to electricity as the main energy carrier for light vehicles. As electrified vehicles are significantly more efficient, overall energy used in light-duty road transportation does not grow and by 2030 starts to decline. The pace of the decline, which is most pronounced in the demand for hydrocarbon fuels, differs across the scenarios.

- The global light duty vehicle parc continues to expand in all three scenarios. Most of the growth is seen in emerging economies. In developed economies, parc growth is much more limited. By 2050, the light duty parc reaches 2.5 billion vehicles in all three scenarios, an increase of over 60% compared to 2019.

- As the parc grows and its composition turns over it becomes more efficient. These efficiency gains are driven by both regulation and the diffusion of improved technology. The retirement of older, inefficient vehicles and the addition of new vehicles with improved internal combustion engines enhance the efficiency of the ICE parc. Electrification, where new vehicles with electric powertrains replace ICE vehicles, brings substantial additional efficiency gains as electric motors do not produce the waste heat of ICE engines.

- The larger vehicle parc supports growth in total vehicle kilometres driven (Vkm). The electrification of the parc leads to rapid growth in electric kilometres, and a corresponding decline in the kilometres driven by ICE vehicles.

- This change is prompted initially by policy and regulation but is sustained by the increasing cost competitiveness of EVs. The cost reductions in EVs are enabled by continuing falls in the cost of batteries and the scale up in the manufacturing of electric variants and their components.

- All three scenarios assume that investment in charging infrastructure and supply of critical minerals and other raw materials is sufficient to enable the rapid growth in the EV parc.

- The shift in composition of the vehicle parc leads to falling demand for hydrocarbon fuels in light duty vehicles. That trend accelerates as policies to limit sales of new ICE vehicles increasingly bite over the second half of the Outlook.

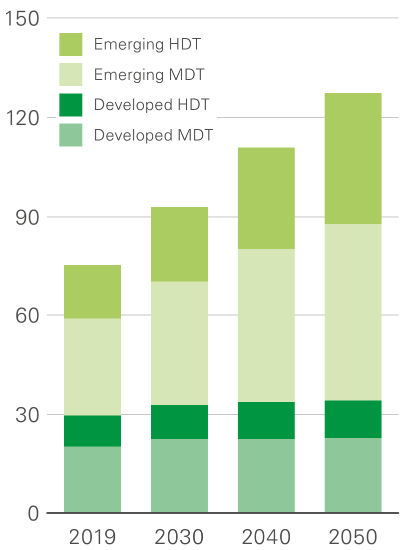
- Light duty parc electrification, along with a decarbonization of the power sector, is critical to achieving broader decarbonization. The energy mix that results sees the share of oil products fall from >90% in 2019 to between 20 and 60% in 2050 in the three scenarios. In contrast, the electricity share rises from <1% to between 30 and 70%.

- Biofuels, blended with refined products, currently make up around 4% of the light duty energy mix, and that share increases a little in the near term as blend rates trend upwards toward engine and infrastructure limits. However, over time, biofuel content also falls in line with oil product demand as electrification wins out.

The decarbonization of heavier vehicles leads to a more diverse range of alternative fuels, with electricity taking the biggest share

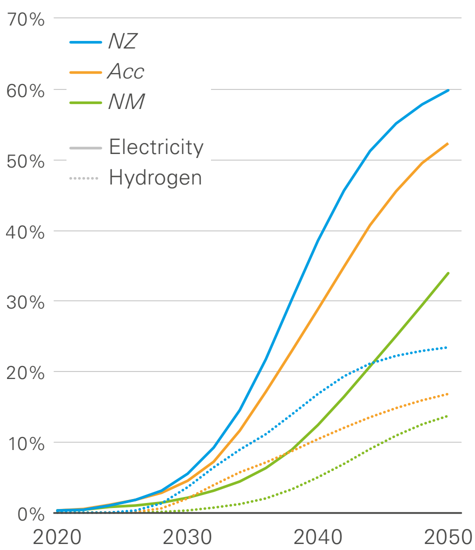
Medium and heavy vehicle parc in *Accelerated*

Millions



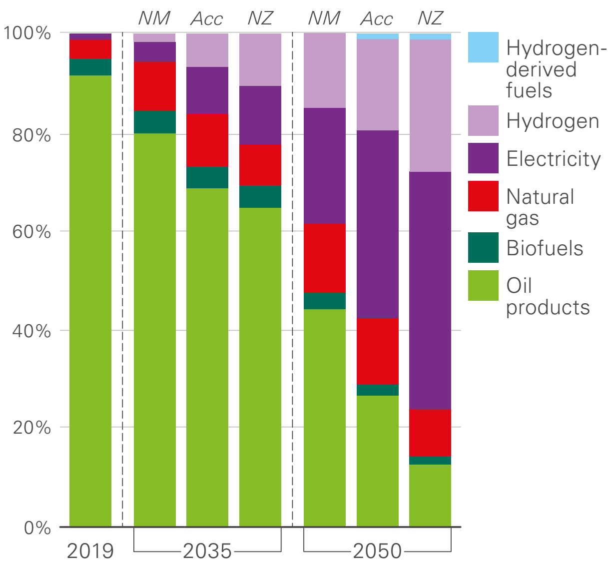
Medium and heavy vehicle kilometres: Electricity vs hydrogen

% share



Medium and heavy vehicle energy share

% share



*Vehicle abbreviations: HDT (heavy duty truck), MDT (medium duty truck)

Key points

There are significant parallels with light duty in the prospects for medium- and heavy-duty vehicles. The growth of the global economy requires more vehicles to transport goods, with almost all of the parc expansion taking place in emerging economies. As regulation requires decarbonization, liquid fuels are replaced largely by electricity, supported by hydrogen. Natural gas including biomethane also plays a role.

- The global parc of medium- and heavy-duty vehicles expands from around 75 million to over 125 million in all three scenarios by 2050. That growth is driven by growing prosperity and expanding output, focused particularly in emerging economies. While the parc has many more medium-duty trucks (<16 metric tonnes gross vehicle weight (MT GVW), 65% of parc), the energy consumption of heavy-duty trucks (>16 MT GVW) is around 40% greater on a MJ per km basis.

- Today around 95% of medium- and heavy-duty trucks are fuelled by diesel, with only a small minority using alternatives such as compressed or liquified natural gas. Across the three scenarios, the mix of powertrains becomes more diverse, with diesel being replaced by a mix of electricity, hydrogen, and natural gas (including biomethane).

- The main alternatives to diesel are electricity and hydrogen. The choice between electricity and hydrogen is finely balanced and depends on use case. The use of electricity requires vehicles with large, expensive batteries and time-consuming high-powered charging to refuel. In contrast, hydrogen trucks offer faster refuelling and greater range flexibility, but also require costly fuel cell stacks and gaseous storage. The choice between fuels also depends on the relative delivered prices of electricity and low-carbon hydrogen. In both cases, achieving strong adoption requires material vehicle cost reductions, as well as the development of charging and refuelling networks.

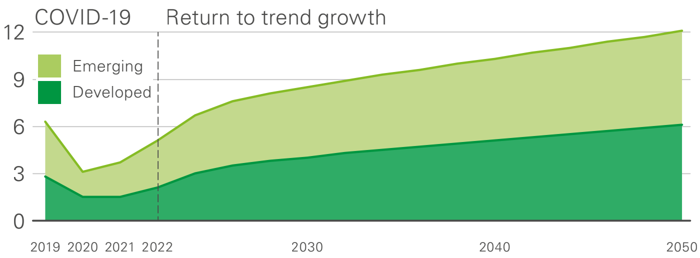
- Across our scenarios, electricity achieves somewhat stronger take-up across the main trucking categories, although hydrogen also achieves substantial penetration, particularly in long-distance use cases.

- Medium- and heavy-duty trucks and buses are high consumers of oil products today. As the parc shifts towards low carbon solutions, the impact on oil product demand increases.

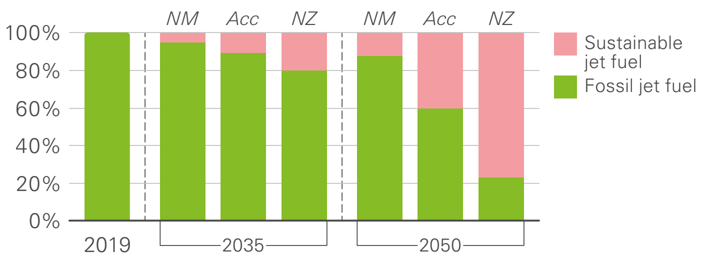
- The oil product share of total energy demand declines from over 90% in 2019 to 70-75% by 2035 in *Accelerated* and *Net Zero*, causing oil used in trucking to fall by 2 Mb/d. Electricity reaches 40-50% of the energy mix in these two scenarios by 2050, while the hydrogen share is between 20 and 30%. In contrast, electricity and hydrogen develop more slowly in *New Momentum*, reaching around 25% and 15% respectively.

Aviation energy is gradually decarbonized as new supply chains increase the availability of sustainable liquid jet fuels

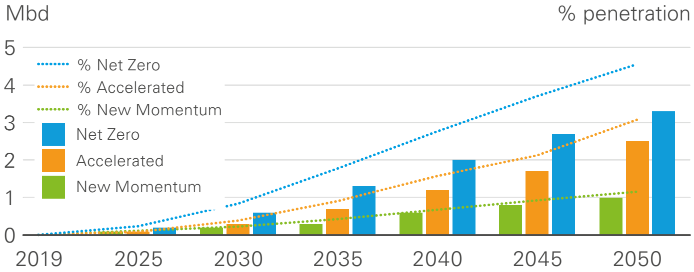
Passenger kilometres in *Accelerated*



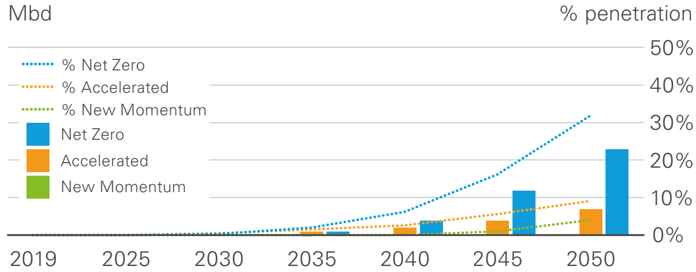
Aviation energy share



Sustainable aviation fuel: bio-derived



Sustainable aviation fuel: hydrogen-derived



Key points

Aviation demand recovers strongly from COVID-19 disruption and grows significantly to 2050 across all three scenarios. The incumbent fleet and long-haul range requirements mean that liquid fuels continue to dominate over the Outlook, with the decarbonization of aviation driven by the increasing penetration of sustainable liquid jet fuel (SAF), in the form of both bio-based and fully synthetic SAF.

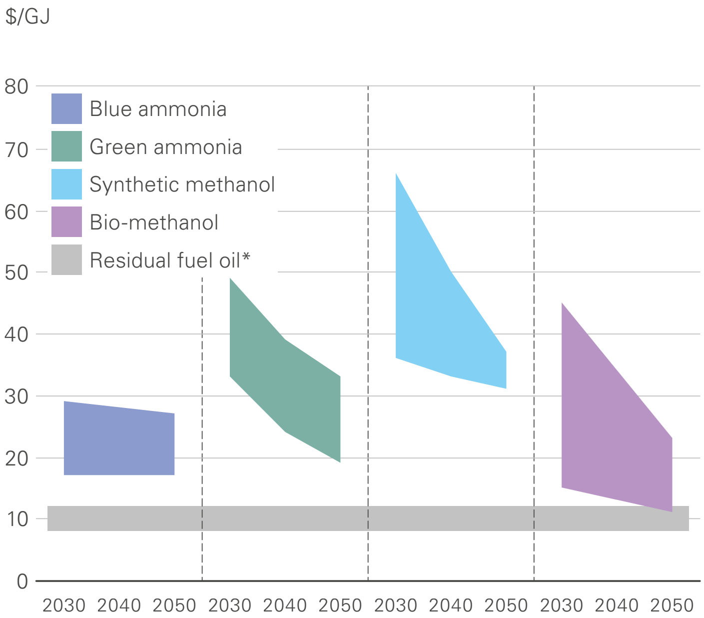
- Aviation was the most impacted transportation sector during the COVID-19 pandemic, with demand for aviation fuels falling by 50% relative to pre-pandemic levels.
- As COVID-19 restrictions were relaxed, domestic aviation demand recovered fastest. International demand has now followed in many parts of the world, although in 2023, Asia Pacific recovery is still lagging.
- Looking out to 2050, demand grows significantly in all three scenarios, with growth fastest in emerging economies.

Global passenger kilometres increase 70-115% between 2019 and 2050 in the scenarios, with lower demand in *Accelerated* and *Net Zero* reflecting higher fuel prices and consumer choices to avoid flying.

- The combination of the slow turnover of the current liquid-fuel based fleet and the range requirements for longer haul flights mean that electric and hydrogen-based solutions play a limited role in the decarbonization of the aviation sector.
- Instead, the decarbonization of aviation is driven by the increasing role of SAF. In *New Momentum*, SAF reaches around 5% of the jet pool by 2035, based largely on bio-based SAF. In *Accelerated* and *Net Zero*, the combination of bio- and hydrogen-based SAF reach between 10% and 20%. By 2050, in *Accelerated* and *Net Zero*, penetration grows to between 40 and 70%.
- The increasing role played by SAF is underpinned by a significant increase in production capacity, with between 15 and 30 world-scale facilities coming online every year between the 2030s and mid-2040s.
- The early penetration of SAF is led by bio-based fuels, initially derived from HEFA (hydroprocessed esters and fatty acid) from sustainable vegetable oil-based feedstocks and subsequently from Fischer–Tropsch (FT)-based conversion of municipal solid waste and other non-food biomass, as well as alcohol-to-jet technology. Across the three scenarios, this accounts for 5-20% of total jet fuel in 2035, and 10-40% by 2050.
- Hydrogen-derived solutions to create synthetic jet fuel form a growing part of the aviation energy mix over time, especially in *Net Zero* scenario, as second generation biojet encounters limits in its ability to scale, and improvements in technology and increasing production capacity cause the relative cost of synthetic jet fuel to fall. In *Accelerated* and *Net Zero* hydrogen-derived synthetic fuels are 1-2% of total jet fuel in 2035 but reach 10-30% in 2050.

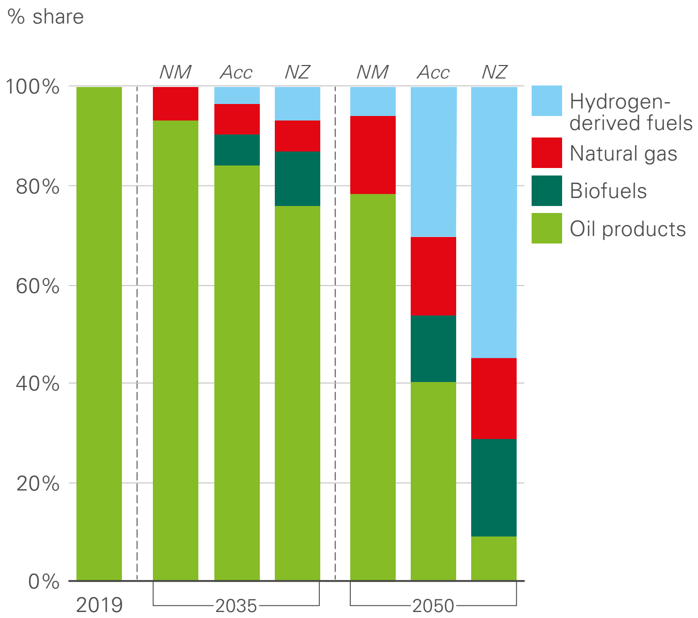
The carbon intensity of the marine sector is gradually reduced, led by the increasing use of hydrogen-derived fuels

Cost of future marine fuels



*Historic range 2015-22

Marine energy share



Key points

Seaborne trade grows in all three scenarios, with economical shipping of goods and raw materials a critical element of the continued growth of the global economy. Decarbonization of the marine sector requires the gradual transition of the fleet to new fuels, led by hydrogen-based fuels (ammonia and methanol), supported by growing roles for biofuels and natural gas.

The current marine fleet relies almost entirely on oil products, with alternative, low-carbon energy sources currently significantly more expensive. The cost of fuels is critical. For large ships, the cost of fuel over their lifetime can be many multiples of the initial build cost.

- Both hydrogen-derived fuels and biofuels form significant parts of the marine energy mix in *Accelerated* and *Net Zero* by 2050. Amongst hydrogen-based fuels, ammonia looks set to be the lowest cost solution at scale, although it presents handling challenges that need to be tested and determined to be safe for widespread use. In addition, ammonia-based marine engine technology is still in development although likely to come to market in the near future. Methanol also has operational challenges, caused by its low flashpoint (although dual-fuel engines that can use it are available today) and its likely higher cost of supply at the scale required.

- The initial decline in oil product fuels is largely offset by growth in liquefied natural gas (LNG) with the potential to increasingly swap fossil- for bio-methane. This reflects that in recent years, LNG has been the strongest growing alternative to incumbent oil products and in the short term, continues to offer reduced emissions versus fuel oil or gas oil.

- Further ahead, hydrogen-derived fuels and biofuels take an increasingly large share of the marine energy mix in *Accelerated* and *Net Zero*. The transition to these fuels accelerates as increasing amounts of the existing fleet are turned over, allowing alternative fuels to be adopted. By 2050, in *Accelerated* and *Net Zero*, the penetration of hydrogen-derived fuels reaches 30-55% and biofuels 10-20%, as oil products decline to between 40 and 10%.

- The growth of these alternative fuels in *Accelerated* and *Net Zero* is supported by significant development of bunkering facilities, including fuel storage, and refuelling barges, as well as growth in manufacturing capacity needed to supply the required fuels.

Annex

Data tables

	2019	Level in 2050* Acc	Net Zero	NM	Change 2019-2050 (p.a.) Acc	Net Zero	NM	Share of primary energy in 2050 Acc	Net Zero	NM
Primary energy by fuel										
Total	627	666	630	733	0.2%	0.0%	0.5%	100%	100%	100%
Oil	193	78	39	140	-2.9%	-5.0%	-1.0%	12%	6%	19%
Natural gas	140	87	60	166	-1.5%	-2.7%	0.5%	13%	9%	23%
Coal	158	23	17	96	-6.0%	-7.0%	-1.6%	4%	3%	13%
Nuclear	25	40	47	28	1.5%	2.1%	0.4%	6%	7%	4%
Hydro	38	61	65	48	1.6%	1.8%	0.8%	9%	10%	7%
Renewables (incl. bioenergy)	74	377	403	256	5.4%	5.6%	4.1%	57%	64%	35%
Native units										
Oil (Mb/d)	98	42	21	73						
Natural gas (Bcm)	3900	2422	1658	4616						
Primary energy by region										
Developed	234	171	162	199	-1.0%	-1.2%	-0.5%	26%	26%	27%
US	97	76	74	89	-0.8%	-0.9%	-0.3%	11%	12%	12%
EU	65	45	42	51	-1.2%	-1.4%	-0.8%	7%	7%	7%
Emerging	393	495	468	534	0.8%	0.6%	1.0%	74%	74%	73%
China	147	149	138	160	0.0%	-0.2%	0.3%	22%	22%	22%
India	42	88	88	94	2.5%	2.4%	2.6%	13%	14%	13%
Middle East	37	47	45	48	0.7%	0.6%	0.8%	7%	7%	7%
Russia	30	30	26	32	-0.1%	-0.4%	0.1%	4%	4%	4%
Brazil	16	17	15	18	0.2%	-0.1%	0.5%	2%	2%	3%

	2019	Level in 2050* Acc	Net Zero	NM	Change 2019-2050 (p.a.) Acc	Net Zero	NM	Share of total final consumption in 2050 Acc	Net Zero	NM
Total final consumption by sector										
Total	477	398	335	513	-0.6%	-1.1%	0.2%	100%	100%	100%
Transport	119	100	90	114	-0.6%	-0.9%	-0.1%	25%	27%	22%
Industry	188	153	128	203	-0.7%	-1.3%	0.2%	38%	38%	40%
Feedstocks	38	36	27	45	-0.2%	-1.0%	0.6%	9%	8%	9%
Buildings	132	110	90	151	-0.6%	-1.2%	0.4%	28%	27%	29%
Generation by carrier										
Electricity ('000 TWh)	27	57	61	50	2.4%	2.7%	2.0%	52%	66%	35%
Hydrogen (Mt)	66	301	460	165	5.0%	6.4%	3.0%	9%	17%	4%
Production										
Oil (Mb/d)	98	42	21	73	-2.7%	-4.8%	-0.9%			
Natural gas (Bcm)	3976	2422	1658	4616	-1.6%	-2.8%	0.5%			
Coal (EJ)	168	27	15	92	-5.7%	-7.4%	-1.9%			
Emissions										
Net emissions from energy and industry (Gt of CO_2e)	39.8	9.1	2.0	28.7	-4.7%	-9.1%	-1.1%			
Carbon capture use & storage (Gt)	0.0	4.1	6.1	1.1	56%	58%	49%			
Macro										
GDP (trillion US$ PPP)	128	266	266	266	2.4%	2.4%	2.4%			
Energy intensity (MJ of TFC per US$ of GDP)	3.7	1.5	1.3	1.9	-2.9%	-3.5%	-2.1%			

*Exajoules (EJ) unless otherwise stated

Modelling the impact of the Russia-Ukraine war on the global energy system

The impact of the Russia-Ukraine war was modelled by capturing three types of economic shock associated with the war: near-term commodity price (stagflation) shock, heightened energy security concerns, and a reduced pace of globalization.

Commodity price shock

This shock is modelled as a sharp but transitory increase in fossil fuel prices, combined with significantly lower global GDP. Real interest rates are also higher as central banks tighten monetary policy to control inflation, which increase the levelized costs of different energy sources, affecting the relative prices of alternative technologies. The shock dissipates by 2030, by which time prices and, in almost all cases, GDP levels have returned to their long-term trend. The exception to this is the level of GDP in Russia and Ukraine, where the war is assumed to have a persistent negative impact on GDP.

Heightened energy security concerns

The Russia-Ukraine war is assumed to cause governments to implement policies to reduce their dependency on imported energy. The shock is modelled by adding a c.30% 'security' premium to the price of the energy imported into each region or country. This premium is increased to roughly 60% for energy imported by the EU given its particular exposure to war-related disruption and the need to reduce imports from Russia rapidly. The security premium imposed on imported energy increases the competitiveness of domestically produced energy, including renewables, nuclear and hydro power.

Reduced pace of globalization

The war in Ukraine is assumed to reduce the pace of globalization, as countries and regions heighten their focus on domestic resilience and reduce their exposure to international shocks. The lower profile for international trade and openness has a small but negative impact on global economic growth. Although the effect is small on a yearly basis – reducing average annual growth by around 0.1 percentage point – the impact on the level of GDP compounds over time, reducing the level of global GDP by around 4% in 2050.

The impact from this reduced pace of globalization is assumed to have different effects in different countries and regions: with those economies whose future economic growth is particularly dependent on international trade and on the sharing of ideas and productivity the most heavily impacted. For example, the shock has a much larger impact on emerging Asian economies than on the United States. The methodology used to calibrate the deglobalization shock is based on the trade growth literature, including studies by the World Bank (2017) and Alcala and Ciccone (2004).

Although these three shocks are assumed to take effect immediately, their peak effects occur over different time frames. In the short term (up until around 2025), the commodity price shock is the most impactful. In the medium term (around 2030-2035), the impact from heightened energy security concerns has the largest impact on the energy system. In the longer term, the lower level of global activity caused by reduced pace of globalization is preeminent.

Sources:

World Bank (2017) 'The Global Costs of Protectionism'. Policy Research working paper, no. WP 8277.

Alcala, F. and Ciccone, A. (2004) 'Trade and Productivity'. The Quarterly Journal of Economics, 119 (2), pp. 613-646.

The economic impact of climate change

The GDP profiles used in the *Energy Outlook* come from Oxford Economics (OE). These long-term forecasts incorporate estimates of the economic impact of climate change. These estimates draw on the latest research in the scientific literature and follow a similar methodology to that used in *Energy Outlook 2020* and *Energy Outlook 2022*.

OE updated and extended the estimation approach developed by Burke, Hsiang and Miguel (2015), which suggests a non-linear relationship between productivity and temperature, in which per capita income growth rises to an average (population weighted) temperature of just under 15°C ((Burke et al.'s initial assessment was 13°C). This temperature curve suggests that 'cold country' income growth increases with annual temperatures. However, at annual temperatures above 15°C, per capita income growth is increasingly adversely affected by higher temperatures.

The OE emissions forecasts are broadly in line with the IEA STEPS scenario and assume average global temperatures will reach 2°C above pre-industrial levels by 2050. The results suggest that in 2050 global GDP is around 2% lower than in a counterfactual scenario where the temperature change remained at the current level. The regional impacts are distributed according to the evolution of their temperatures relative to the concave function estimated by OE. While OE's approach captures channels associated with average temperatures, these estimates remain uncertain and incomplete; they do not, for example, explicitly include impact from migration or extensive coastal flooding.

The mitigation costs of actions to decarbonize the energy system are also uncertain, with significant variations across different external estimates. Most estimates, however, suggest that the upfront costs increase with the stringency of the mitigation effort, suggesting that they are likely to be bigger in *Accelerated* and *Net Zero* than in *New Momentum*. Estimates published by the IPCC (AR5 – Chapter 6) suggest that for scenarios consistent with keeping global temperature increases to well below 2°C, median estimates of mitigation costs range between 2-6% of global consumption by 2050.

Given the huge range of uncertainty surrounding estimates of the economic impact of both climate changes and mitigation, and the fact that all three of the main scenarios include both types of costs to a greater or lesser extent, the GDP profiles used in the *Outlook* are based on the illustrative assumption that these effects reduce GDP in 2050 by around 2% in all three scenarios, relative to the counterfactual in which temperatures are held constant at recent average levels.

Sources:

Burke, M., Hsiang, S. & Miguel, E. Global non-linear effect of temperature on economic production. Nature 527, 235–239 (2015) https://www.nature.com/articles/nature15725

The global aggregate mitigation cost estimates in terms of GDP losses are taken from IPCC AR5 – Chapter 6: https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_chapter6.pdf

Investment methodology

Oil and gas upstream

Implied levels of oil and gas investment are derived from the production levels in each scenario. Upstream oil and natural gas capital expenditure includes well capex (costs related to well construction, well completion, well simulation, steel costs and materials), facility capex (costs to develop, install, maintain, and modify surface installations and infrastructure) and exploration capex (costs incurred to find and prove hydrocarbons). It excludes operating costs and midstream capex such as capex associated with developing LNG liquefaction capacity.

Asset level production profiles are aggregated by geography, supply segment (onshore, offshore, shale and oil sands), supply type (crude, condensates, NGLs, natural gas) and developmental stage, i.e., classified by whether the asset is currently producing, under development, or non-producing and unsanctioned. As production from producing and sanctioned assets declines, incremental production from infill drilling and new, unsanctioned assets is called on to meet the oil and gas demand shortfalls. The investment required to bring this volume online is then added to any capital costs associated with maintaining producing and sanctioned projects. The average 2022-2050 decline rate for assets currently producing and under development is around 4.5% p.a. for both oil and for natural gas, although this varies widely by segment and hydrocarbon type. All estimates are derived using asset-level assessments from Rystad Energy.

Wind and solar

Wind and solar energy investment requirements are based on the capital expenditure costs associated with the deployment profiles of each technology in each scenario.

Wind and solar deployment profiles include both renewable power capacity for end-use and for green hydrogen production. The deployment profiles also consider the potential impact of curtailment.

Capital expenditure costs are assigned to each scenario based on their historical values and estimated future evolution. They are differentiated by technology, region and scenario using a combination of internal bp estimates and external benchmarking. The capital expenditure figures do not include the incremental wider system integration costs associated with wind and solar deployment.

Carbon emissions definitions and sources

Unless otherwise stated, carbon emissions refer to CO_2 emissions from:

- energy use (i.e. the production and use of energy in the three final end-use sectors: industry, transport and buildings),
- most non-energy related industrial processes,
- natural gas flaring,
- methane emissions associated with the production, transmission and distribution of fossil fuels, expressed in CO_2 equivalent terms.

CO_2 emissions from industrial processes refer only to non-energy emissions from cement production. CO_2 emissions associated with the production of hydrogen feedstock for ammonia and methanol are included under hydrogen sector emissions.

Historical data for natural gas flaring data is taken from VIIRS Nightfire (VNF) data and produced by the Earth Observation Group (EOG), Payne Institute for Public Policy, Colorado School of Mines. The profiles for natural gas flaring in the scenarios assume that flaring moves in line with wellhead upstream output.

Historical data on methane emissions associated with the production, transportation and distribution of fossil fuels are sourced from IEA estimates of greenhouse gas emissions. The profiles for future methane emissions assumed in the scenarios are based on fossil fuel production and take account of recent policy initiatives such as the Global Methane Pledge. The net change in methane emissions is the aggregation of future changes to fossil fuel production and methane intensity.

There is a wide range of uncertainty with respect to both current estimates of methane emissions and the global warming potential of methane emissions. The methane to CO_2e factor used in the scenarios is a 100-year Global Warming Potential (GWP) of 25, recommended by the IPCC in AR4. This conversion factor is used to ensure alignment with financial and government reporting standards, and to ensure consistency across all bp corporate reporting. In particular, this is the same factor to be used in the bp Annual Report, also published in Q1 2023.

IPCC scenarios and emissions methodology

We use scenarios that are in the database corresponding to the Sixth Assessment Report published in 2022. This database is hosted by the International Institute for Applied Systems Analysis (IIASA) as part of a cooperation agreement with Working Group III of the IPCC.

The scenarios used in the analysis are those labelled as:

Scenarios C1: these scenarios are referred to as scenarios that limit warming to 1.5°C (>50%) with no or limited overshoot.

Scenarios C3a: these scenarios are referred to as scenarios that limit warming to 2°C (>67%) with immediate action.

Cumulative CO_2e emissions in 2015-2050 are the addition of CO_2 emissions from energy and industrial processes and methane emissions from energy supply transformed into CO_2e using a factor Global Warming Potential of 25. The AR6 Scenarios Database report data for every five years. For the missing intermediate years, a linear interpolation is used.

Sources

Andrew, R.M., 2019. Global CO_2 emissions from cement production, 1928–2018. Earth System Science Data 11, 1675–1710, (updated dataset July 2021)

IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds).

VIIRS Nightfire (VNF) produced by the Earth Observation Group (EOG), Payne Institute for Public Policy, Colorado School of Mines.

IEA (2021), Greenhouse Gas Emissions from Energy Data Explorer, IEA, Paris

IPCC Fourth Assessment Report: Climate Change 2007.

IPCC Sixth Assessment Report – Climate Change 2022: Impacts, Adaptation and Vulnerability

IEA (2021), Methane Tracker 2021, IEA, Paris

Sustainability Reporting Guidance for the Oil and Gas Industry, 4th Edition, 2020. IPIECA/API/IOGP.

Edward Byers, Volker Krey, Elmar Kriegler, Keywan Riahi, Roberto Schaeffer, Jarmo Kikstra, Robin Lamboll, Zebedee Nicholls, Marit Sanstad, Chris Smith, Kaj-Ivar van der Wijst, Alaa Al Khourdajie, Franck Lecocq, Joana Portugal-Pereira, Yamina Saheb, Anders Strømann, Harald Winkler, Cornelia Auer, Elina Brutschin, Matthew Gidden, Philip Hackstock, Mathijs Harmsen, Daniel Huppmann, Peter Kolp, Claire Lepault, Jared Lewis, Giacomo Marangoni, Eduardo Müller-Casseres, Ragnhild Skeie, Michaela Werning, Katherine Calvin, Piers Forster, Celine Guivarch, Tomoko Hasegawa, Malte Meinshausen, Glen Peters, Joeri Rogelj, Bjorn Samset, Julia Steinberger, Massimo Tavoni, Detlef van Vuuren. AR6 Scenarios Database hosted by IIASA International Institute for Applied Systems Analysis, 2022.

Other data definitions and sources

Data definitions are based on the bp Statistical Review of World Energy, unless otherwise noted. Data used for comparisons, unless otherwise noted, are rebased to be consistent with the bp Statistical Review.

Primary energy, unless otherwise noted, comprises commercially traded fuels and traditional biomass. In this Outlook, primary energy is derived using:

- the substitution method - which grosses up energy derived from non-fossil power by the equivalent amount of fossil fuel required to generate the same volume of electricity in a thermal power station. The grossing assumption is time varying, with the simplified assumption that efficiency will increase linearly from 40% today to 45% by 2050

Gross Domestic Product (GDP) is expressed in terms of real Purchasing Power Parity (PPP) at 2015 prices.

Sectors

Transport includes energy used in heavy road, light road, marine, rail and aviation. Electric vehicles include all four wheeled vehicles capable of plug-in electric charging. Industry includes energy used in commodity and goods manufacturing, construction, mining, the energy industry including pipeline transport, and for transformation processes outside of power, heat and hydrogen generation. Feedstocks includes non-combusted fuel that is used as a feedstock to create materials such as petrochemicals, lubricant and bitumen. Buildings includes energy used in residential and commercial buildings, agriculture, forestry, fishing and non-specified consumption.

Regions

Developed is approximated as North America plus Europe plus Developed Asia. Emerging refers to all other countries and regions not in Developed. China refers to the Chinese Mainland. Developed Asia includes OECD Asia plus other high income Asian countries and regions. Emerging Asia includes all countries and regions in Asia excluding mainland China, India and Developed Asia.

Fuels, energy carriers, carbon and materials

Oil, unless otherwise noted, includes crude (including shale oil and oil sands), natural gas liquids (NGLs), gas-to-liquids (GTLs), coal-to-liquids (CTLs), condensates, and refinery gains. Hydrogen-derived fuels are all fuels derived from low-carbon hydrogen, including ammonia, methanol, and other synthetic hydrocarbons.

Renewables, unless otherwise noted, includes wind, solar, geothermal, biomass, biomethane, and biofuels and exclude large-scale hydro. Non-fossils include renewables, nuclear and hydro. Traditional biomass refers to solid biomass (typically not traded) used with basic technologies e.g. for cooking.

Hydrogen demand includes its direct consumption in transport, industry, buildings, power and heat, as well as feedstock demand for the production of hydrogen-derived fuels and for conventional refining and petrochemical feedstock demand.

Low-carbon hydrogen includes green hydrogen, and hydrogen produced from biomass with CCUS, gas with CCUS, and coal with CCUS. CCUS options include CO_2 capture rates of 93-98% over the *Outlook*. The global average methane emissions rate for the gas or coal consumed to produce blue hydrogen is between 1.4-0.7% over the *Outlook*.

Key data sources

BP p.l.c., bp Statistical Review of World Energy, London, United Kingdom, June 2021

International Energy Agency, World Energy Statistics, September 2021

International Energy Agency, World Energy Balances, July 2021

Oxford Economics, Global GDP Forecasts, 2022

United Nations, Department of Economic and Social Affairs, Population Division (2019). World Population Prospects 2019, Online Edition. Rev. 1

IEA (2021), Methane Tracker 2021, IEA, Paris

Sustainability Reporting Guidance for the Oil and Gas Industry, 4th Edition, 2020. IPIECA/API/IOGP.

Disclaimer

This publication contains forward-looking statements – that is, statements related to future, not past events and circumstances. These statements may generally, but not always, be identified by the use of words such as 'will', 'expects, 'is expected to', 'aims', 'should', 'may', 'objective', 'is likely to', 'intends', 'believes', anticipates, 'plans', 'we see' or similar expressions. In particular, the following, among other statements, are all forward looking in nature: statements regarding the global energy transition, increasing prosperity and living standards in the developing world and emerging economies, expansion of the circular economy, urbanization and increasing industrialization and productivity, energy demand, consumption and access, impacts of the Coronavirus pandemic, the global fuel mix including its composition and how that may change over time and in different pathways or scenarios, the global energy system including different pathways and scenarios and how it may be restructured, societal preferences, global economic growth including the impact of climate change on this, population growth, demand for passenger and commercial transportation, energy markets, energy efficiency, policy measures and support for renewable energies and other lower-carbon alternatives, sources of energy supply and production, technological developments, trade disputes, sanctions and other matters that may impact energy security, and the growth of carbon emissions.

Forward-looking statements involve risks and uncertainties because they relate to events, and depend on circumstances, that will or may occur in the future. Actual outcomes may differ materially from those expressed in such statements depending on a variety of factors, including: the specific factors identified in the discussions expressed in such statements; product supply, demand and pricing; political stability; general economic conditions; demographic changes; legal and regulatory developments; availability of new technologies; natural disasters and adverse weather conditions; wars and acts of terrorism or sabotage; public health situations including the impacts of an epidemic or pandemic and other factors discussed in this publication. bp disclaims any obligation to update this publication or to correct any inaccuracies which may become apparent. Neither BP p.l.c. nor any of its subsidiaries (nor any of their respective officers, employees and agents) accept liability for any inaccuracies or omissions or for any direct, indirect, special, consequential or other losses or damages of whatsoever kind in or in connection with this publication or any information contained in it.

bp Energy Economics

EXHIBIT G

Science

Canadian oil production could peak as early as 2026 in net-zero future, energy regulator says

Canada Energy Regulator's first-ever net-zero modeling shows huge shifts in energy use and fossil fuel exports

Inayat Singh · CBC News · Posted: Jun 20, 2023 9:01 PM CDT | Last Updated: June 20

Suncor's plant in Fort McMurray, Alta., is shown. In a net-zero emissions future, Canadian oil production is set to decline significantly, according to modelling done by the Canada Energy Regulator. (Jason Franson/The Canadian Press)

comments

For the first time, Canada's national energy regulator has looked at how oil and gas production will change in a net-zero world, where countries hit their climate goals — and it shows a future without much demand for Canadian fossil fuels.

In its widely read annual report on the country's energy future, the Canada Energy Regulator (CER) modelled scenarios where the world and Canada successfully head toward net-zero carbon emissions by 2050, which is seen as key to limiting global warming to 1.5 C above pre-industrial levels — the goal of the international Paris Agreement.

The regulator found that in such scenarios, oil and gas production in Canada would start declining as early as 2026, because of falling oil prices and demand, as the rest of the world turns toward cleaner energy sources.

- **Historic profits in oilpatch on track to continue as global oil demand set to jump yet again**

"We can't ignore what's happening internationally, and betting on failure internationally is an economically risky thing to do for Canada," said Dale Beugin, executive vice-president at the Canadian Climate Institute, a climate policy think-tank in Ottawa.

Suncor equipment is shown at their oilsands facilities in Alberta. Canadian oil production will peak in a net-zero emissions future, according to analysis from the Canada Energy Regulator, but exactly when that happens depends on how fast other countries cut their emissions. (Jason Franson/The Canadian Press)

Global prices drive Canadian oil exports

The projections come at a particularly lucrative time for the industry; the five largest companies that operate in Canada's oilsands made about $35 billion in profits in 2022.

But the models should be a warning for many oil and gas companies, climate experts say, calling into question the future of fossil fuel use and production in Canada.

On the other hand, the analysis spells out a dramatically expanded role for cleaner energy in Canada's future, from sources like hydro, wind, nuclear and hydrogen.

"The rate of international decarbonization — the rate at which the rest of the world takes seriously climate change and reduces its emissions, maybe very quickly — has really big implications for demand for the exports of Canadian oil and gas," Beugin said.

"And the biggest threat to the oil and gas sector in Canada isn't domestic climate policy. It is actually market conditions over the longer term."

A aerial view of the Trans Mountain marine terminal in Burnaby, B.C., which serves as a distribution point for crude and refined oil. (Jonathan Hayward/The Canadian Press)

Exactly when oil and gas production peaks depends on how far other countries go in their efforts to slash greenhouse gas emissions, according to the CER. It modelled two net-zero emissions scenarios: one where global emissions head to net-zero by 2050, and one where the world doesn't act as fast, but Canada still heads to net-zero for its own emissions by 2050.

Canada's oil production starts declining by 2026 in the global scenario and by 2029 for the Canada-only scenario, with similar results for gas.

Beugin stressed that these were projections based on different scenarios, and not predictions of what was going to happen.

But the projections could still influence decisions on expanding oil production and investing in carbon capture technologies, which would capture the industry's carbon emissions and keep them out of the atmosphere.

Choosing where to invest

The report shows that "we need to be careful, especially where public money is dedicated. We need to ensure that it goes to projects that are going to be competitive in the long term," said Jan Gorski, director of the oil and gas program at the Pembina Institute, an energy think-tank.

"And not every project will be competitive. Some of those projects will likely come offline as oil demand declines, but some will be competitive and will stick around."

The Quest carbon capture and storage facility in Fort Saskatchewan, Alta. Quest is designed to capture and store more than one million tonnes of CO_2 each year. (Jason Franson/The Canadian Press)

The CER's analysis also looked at how much carbon Canada's oil and gas industry would have to capture during production. In the global net-zero scenario, the industry would need to capture about 22.5 megatonnes of CO_2 per year by 2036.

By the end of 2022, Alberta had the capacity to capture around three megatonnes of CO_2 every year, although this could increase if several proposed carbon capture projects go ahead.

- **Federal tax credit not enough to get carbon capture projects built, Cenovus CEO says**

That depends on more help from the government, according to Mark Cameron, vice-president of external relations at Pathways Alliance, the oilsands industry group.

Cameron says globally, in places like Norway or the U.S, public investment in carbon capture pays for much more of a project's costs than in Canada.

"We need more fiscal certainty," he said.

The need for more public support has been disputed by some. The federal government's tax credit for carbon capture projects is expected to cost about $1.5 billion a year.

Cameron also said he doubts the CER's global net-zero emissions scenario will come to fruition, or that demand for Canadian oil will slow so soon.

"The global net-zero scenario implies a very aggressive collective action on reducing emissions, which, right now, we're not seeing things moving that quickly. Last year, we actually saw oil demand hit a record level in 2022," he said,

"And we're still seeing the Chinese economy rebounding from COVID and so on. So we don't think that we're seeing peak oil demand as early as 2026."

- **Canada examining how to keep its carbon capture competitive in wake of U.S. incentives**
- **Scientists want Ottawa to scrap carbon capture tax credit**

Much more clean electricity

The CER's scenarios show electricity use increasing to power all the electric cars, building heating systems and other clean technologies that will replace fossil fuels in the lives of Canadians. And that new electricity will come from cleaner sources — with wind energy growing nearly seven to nine times its current levels by 2050.

A wind plant in Nova Scotia. The role of wind power, which is one of the cheapest sources of energy, is set to dramatically expand in a net-zero emissions future. (Andrew Vaughan/The Canadian Press)

That's not surprising for Binnu Jeyakumar, director of the electricity program at the Pembina Institute.

"The reason models do this is because wind is the cheapest source of electricity, so it makes sense to build a lot of wind," she said.

That's because wind plants have become much less expensive to build and install and, unlike other power sources like gas plants, they don't consume any fuel — an advantage it shares with solar energy.

"By 2030, you'll get to a place where new wind and solar will be cheaper than existing gas power plants. So that's how fast the economics are changing for clean energy," Jeyakumar said.

'No chance' of residents returning home after fire destroys Vancouver apartment building: fire chief

News - Canada - British Columbia

Singapore executes woman for 1st time in nearly 20 years for drug offence

News - World

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_21-823_Official
Richard	Beatty	rjb1946@aol.com		19281 530th Lane McGregor, MN 55760	Electronic Service	No	OFF_SL_21-823_Official
Sarah	Beimers	sarah.beimers@state.mn.us	Department of Administration - State Historic Preservation Office	50 Sherburne Avenue Suite 203 St. Paul, MN 55155	Electronic Service	No	OFF_SL_21-823_Official
David	Bell	david.bell@state.mn.us	Department of Health	POB 64975 St. Paul, MN 55164	Electronic Service	No	OFF_SL_21-823_Official
Brian	Bell	bell.brian@dorsey.com	Dorsey & Whitney LLP	50 South Sixth St. Suite 1500 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-823_Official
Frank	Bibeau	frankbibeau@gmail.com	White Earth Band of Ojibwe	51124 County Road 118 Deer River, Minnesoa 56636	Electronic Service	No	OFF_SL_21-823_Official
Paul	Blackburn	paul@honorearth.org		PO Box 63 Callaway, MN 56521	Electronic Service	No	OFF_SL_21-823_Official
Ellen	Boardman	eboardman@odonoghuelaw.com	O'Donoghue & O'Donoghue LLP	5301 Wisconsin Ave NW Ste 800 Washington, DC 20015	Electronic Service	No	OFF_SL_21-823_Official
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	60 S 6th St Ste 1500 Minneapolis, MN 55402-4400	Electronic Service	No	OFF_SL_21-823_Official
Dan	Chapman	Daniel.Chapman@xcelenergy.com		N/A	Electronic Service	No	OFF_SL_21-823_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-823_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sean	Copeland	seancopeland@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa	1720 Big Lake Rd Cloquet, MN 55720	Electronic Service	No	OFF_SL_21-823_Official
Rebecca	Cramer	rebacramer@gmail.com		3148 29th Ave S Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-823_Official
Brendan	Cummins	brendan@cummins-law.com	Cummins & Cummins, LLP	1245 International Centre 920 Second Avenue South Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-823_Official
Randall	Doneen	randall.doneen@state.mn.us	Department of Natural Resources	500 Lafayette Rd, PO Box 25 Saint Paul, MN 55155	Electronic Service	No	OFF_SL_21-823_Official
Richard	Dornfeld	Richard.Dornfeld@ag.state.mn.us	Office of the Attorney General-DOC	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul, Minnesota 55101	Electronic Service	No	OFF_SL_21-823_Official
John	Drawz	jdrawz@fredlaw.com	Fredrikson & Byron, P.A.	Suite 1500 60 South Sixth Street Minneapolis, MN 55402-4400	Electronic Service	No	OFF_SL_21-823_Official
Charles	Drayton	charles.drayton@enbridge.com	Enbridge Energy Company, Inc.	7701 France Ave S Ste 600 Edina, MN 55435	Electronic Service	No	OFF_SL_21-823_Official
Kate	Fairman	kate.frantz@state.mn.us	Department of Natural Resources	Box 32 500 Lafayette Rd St. Paul, MN 551554032	Electronic Service	No	OFF_SL_21-823_Official
Annie	Felix Gerth	annie.felix-gerth@state.mn.us		Board of Water & Soil Resources 520 Lafayette Rd Saint Paul, MN 55155	Electronic Service	No	OFF_SL_21-823_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_21-823_Official
Rachel	Freeman	rachel.freeman@scotiabank.com	Global Equity Research / Scotia Capital Inc.	40 King St. W. 65th Floor Toronto, ON, CANADA M5W 2X6	Electronic Service	No	OFF_SL_21-823_Official
Anna	Friedlander	afriedlander@odonoghuelaw.com	O'Donoghue & O'Donoghue LLP	5301 Wisconsin Ave NW Suite 800 Washington, DC 20016	Electronic Service	No	OFF_SL_21-823_Official
John R.	Gasele	jgasele@fryberger.com	Fryberger Buchanan Smith & Frederick PA	700 Lonsdale Building 302 W Superior St Ste 700 Duluth, MN 55802	Electronic Service	No	OFF_SL_21-823_Official
Jacob	Glass	jacob.glass@enbridge.com	Enbridge	7701 France Ave S Edina, MN 55435	Electronic Service	No	OFF_SL_21-823_Official
Todd	Green	Todd.A.Green@state.mn.us	Minnesota Department of Labor & Industry	443 Lafayette Rd N St. Paul, MN 55155-4341	Electronic Service	No	OFF_SL_21-823_Official
Doug	Hayes	doug.hayes@sierraclub.org	Sierra Club	85 2nd St., 2nd Fl San Francisco, CA 94105	Electronic Service	No	OFF_SL_21-823_Official
Gary	Hill	hillx001@umn.edu		50569 218th Pl McGregor, MN 55760	Electronic Service	No	OFF_SL_21-823_Official
Janet	Hill	janethillnew@gmail.com		50569 218th Pl Mcgregor, MN 55760-5592	Electronic Service	No	OFF_SL_21-823_Official
Thomas	Hingsberger	thomas.j.hingsberger@usace.army.mil	Corps of Engineers, St. Paul District	180 5th St E Ste 700 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-823_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Terry	Hokenson	terryhokn@gmail.com		3352 Prospect Ter SE Minneapolis, MN 55414	Electronic Service	No	OFF_SL_21-823_Official
Kathleen	Hollander	kath77holl77@gmail.com		3824 Edmund Blvd Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-823_Official
John	Hottinger	jchnorthstar@gmail.com	Hottinger Consulting LLC	14 Irvine Park Unit 14A St. Paul, MN 55102	Electronic Service	No	OFF_SL_21-823_Official
Kari	Howe	kari.howe@state.mn.us	DEED	332 Minnesota St, #E200 1ST National Bank Bldg St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-823_Official
Samuel	Jackson	sam@cummins-law.com		1245 International Centre 920 Second Ave South Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-823_Official
Susu	Jeffrey	susujeffrey@msn.com	Friends of Coldwater	1063 Antoinette Ave Minneapolis, MN 55405	Electronic Service	No	OFF_SL_21-823_Official
Ray	Kirsch	Raymond.Kirsch@state.mn.us	Department of Commerce	85 7th Place E Ste 500 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-823_Official
Anthony	Kit	a.kit@kghl.net		2828 N Harwood St Suite 1240 Dallas, TX 75202	Electronic Service	No	OFF_SL_21-823_Official
Rachel	Kitze Collins	rakitzecollins@locklaw.com	Lockridge Grindeal Nauen PLLP	100 Washington Ave S Suite 2200 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-823_Official
Chad	Konickson	chad.konickson@usace.army.mil	U.S.Army Corps of Engineers	180 5th St # 700 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-823_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Stacy	Kotch Egstad	Stacy.Kotch@state.mn.us	MINNESOTA DEPARTMENT OF TRANSPORTATION	395 John Ireland Blvd. St. Paul, MN 55155	Electronic Service	No	OFF_SL_21-823_Official
Winona	LaDuke	winonaladuke1@gmail.com	Honor the Earth	607 Main Avenue Callaway, MN 56521	Electronic Service	No	OFF_SL_21-823_Official
Michelle	Lommel	mlommel@GREnergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_21-823_Official
Otto Edwin	Lueck	N/A		18719 US Hwy 2 Warba, MN 55793	Paper Service	No	OFF_SL_21-823_Official
Patrick	Mahlberg	pmahlberg@fredlaw.com	Fredrikson & Byron, P.A.	60 S Sixth St Ste 1500 Minneapolis, MN 55402-4400	Electronic Service	No	OFF_SL_21-823_Official
Philip	Mahowald	pmahowald@thejacobsonlawgroup.com	Jacobson Law Group	180 East Fifth Street Suite 940 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-823_Official
Dawn S	Marsh	dawn_marsh@fws.gov	U.S. Fish & Wildlife Service	Minnesota-Wisconsin Field Offices 4101 American Blvd E Bloomington, MN 55425	Electronic Service	No	OFF_SL_21-823_Official
Joseph	Martoglio	Joseph.R.Martoglio@jpmchase.com		N/A	Electronic Service	No	OFF_SL_21-823_Official
Hayk	Minasian	hminasian@trlm.com		N/A	Electronic Service	No	OFF_SL_21-823_Official
John	Munter	mumooatthefarm@yahoo.com		14860 Bruce Crk Rd Warba, MN 55793	Electronic Service	No	OFF_SL_21-823_Official
Michael	Murphy	mmurphy@thejacobsonlawgroup.com		180 East Fifth Street Suite 940 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-823_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Charles	Nauen	cnnauen@locklaw.com	Lockridge Grindal Nauen	Suite 2200 100 Washington Avenue South Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-823_Official
Ann	O'Reilly	ann.oreilly@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-823_Official
Andrew	Pearson	stopthewar24@gmail.com		2629 18th Ave S Apt 2 Minneapolis, MN 55407	Electronic Service	No	OFF_SL_21-823_Official
Alice	Peterson	N/A		24153 300th St NW Argyle, MN 56713	Paper Service	No	OFF_SL_21-823_Official
Abbie	Plouff	abbie.plouff@gmail.com		308 E Prince St Apt 522 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-823_Official
Joseph	Plumer	joep@whiteearth.com	Red Lake Band of Chippewa Indians	P.O. Box 567 Red Lake, Minnesota 56671	Electronic Service	No	OFF_SL_21-823_Official
Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND	81 E Little Canada Road St. Paul, Minnesota 55117	Electronic Service	No	OFF_SL_21-823_Official
James W.	Reents	jwreents@gmail.com		4561 Alder Ln NW Hackensack, MN 56452	Electronic Service	No	OFF_SL_21-823_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-823_Official
Jason	Risdall	regulatoryaffairsUS@enbridge.com	Enbridge	11 East Superior St Suite 125 Duluth, MN 55802	Electronic Service	No	OFF_SL_21-823_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Steve	Roe	roetreat@crosslake.net		11663 Whitefish Ave Crosslake, MN 56442	Electronic Service	No	OFF_SL_21-823_Official
Stephan	Roos	stephan.roos@state.mn.us	MN Department of Agriculture	625 Robert St N Saint Paul, MN 55155-2538	Electronic Service	No	OFF_SL_21-823_Official
Jean	Ross	jfross@umn.edu		3624 Bryant Ave S Minneapolis, MN 55409	Electronic Service	No	OFF_SL_21-823_Official
Akilah	Sanders Reed	akilah.project350@gmail.com		2514 Emerson Ave S Apt 7 Minneapolis, Minnesota 55405	Electronic Service	No	OFF_SL_21-823_Official
Stan	Sattinger	sattinss@aol.com		3933 Twelfth Ave S Minneapolis, MN 55407	Electronic Service	No	OFF_SL_21-823_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-823_Official
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_21-823_Official
Eileen	Shore	eileenshore@outlook.com	Friends of the Headwaters	3137 42nd Ave So Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-823_Official
Mollie	Smith	msmith@fredlaw.com	Fredrikson Byron PA	60 S Sixth St Ste 1500 Minneapolis, MN 554024400	Electronic Service	No	OFF_SL_21-823_Official
Richard	Smith	grizrs615@gmail.com	Friends of the Headwaters	P.O. Box 583 Park Rapids, MN 56470	Electronic Service	No	OFF_SL_21-823_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Scott	Strand	SStrand@elpc.org	Environmental Law & Policy Center	60 S 6th Street Suite 2800 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-823_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_21-823_Official
Christine	Tezak	tezak@cvenergy.com		209 Constitution Avenue, NE Washington, DC 20002	Electronic Service	No	OFF_SL_21-823_Official
Jeremy	Tonet	jeremy.b.tonet@jpmorgan.com		N/A	Electronic Service	No	OFF_SL_21-823_Official
Jayme	Trusty	execdir@swrdc.org	SWRDC	2401 Broadway Ave #1 Slayton, MN 56172	Electronic Service	No	OFF_SL_21-823_Official
Melissa	Turner	melissa.turner@enbridge.com	Enbridge	7701 France Ave S Edina, MN 55435	Electronic Service	No	OFF_SL_21-823_Official
Jen	Tyler	tyler.jennifer@epa.gov	US Environmental Protection Agency	Environmental Planning & Evaluation Unit 77 W Jackson Blvd. Mailstop B-19J Chicago, IL 60604-3590	Electronic Service	No	OFF_SL_21-823_Official
Sara	Van Norman	sara@svn.legal	Van Norman Law, PLLC	Van Norman Law, PLLC 310 4th Ave. S., Ste. 5010 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_21-823_Official
Ken	Vraa	N/A		6623 Peony Lane N Maple Grove, MN 55311	Paper Service	No	OFF_SL_21-823_Official
Cynthia	Warzecha	cynthia.warzecha@state.mn.us	Minnesota Department of Natural Resources	500 Lafayette Road Box 25 St. Paul, Minnesota 55155-4040	Electronic Service	No	OFF_SL_21-823_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tom	Watson	twatson@iphouse.com	Whitefish Area Property Owners Association	39195 Swanburg Court Pine River, MN 56474	Electronic Service	No	OFF_SL_21-823_Official
James	Watts	james.watts@enbridge.com	Enbridge Pipelines (North Dakota) LLC	26 E Superior St Ste 309 Duluth, MN 55802	Electronic Service	No	OFF_SL_21-823_Official
Alan	Whipple	sa.property@state.mn.us	Minnesota Department Of Revenue	Property Tax Division 600 N. Robert Street St. Paul, MN 551463340	Electronic Service	No	OFF_SL_21-823_Official
Colin	Wicker	wicker.colin@dorsey.com	Dorsey & Whitney LLP	50 6th Street South Suite 1500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-823_Official
Jonathan	Wolfgram	Jonathan.Wolfgram@state.mn.us	Office of Pipeline Safety	445 Minnesota St Ste 147 Woodbury, MN 55125	Electronic Service	No	OFF_SL_21-823_Official
David	Zoll	djzoll@locklaw.com	Lockridge Grindal Nauen PLLP	100 Washington Ave S Ste 2200 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-823_Official