19. Wahlperiode

Deutscher Bundestag
Parlamentarischer Beirat für nachhaltige Entwicklung

Wortprotokoll
der 80. Sitzung

Parlamentarischer Beirat für nachhaltige Entwicklung
Berlin, den 19. Mai 2021, 18:00 Uhr
Videokonferenz im Webex-Format

Vorsitz: Dr. Andreas Lenz, MdB

Tagesordnung - Öffentliche Anhörung

Mitglieder des Beirates

	Ordentliche Mitglieder	**Stellvertretende Mitglieder**
CDU/CSU	Benning, Sybille Damerow, Astrid Lenz, Dr. Andreas Marschall, Matern von Stein (Rostock), Peter Whittaker, Kai	Beermann, Maik Färber, Hermann Kruse, Rüdiger Pilsinger, Stephan Pols, Eckhard Weiler, Albert H.
SPD	Scheer, Dr. Nina Thews, Michael Westphal, Bernd	De Ridder, Dr. Daniela Klare, Arno Schäfer (Bochum), Axel
AfD	Kraft, Dr. Rainer Spaniel, Dr. Dirk	Glaser, Albrecht Wiehle, Wolfgang
FDP	Hoffmann, Dr. Christoph Köhler, Dr. Lukas	Bauer, Nicole Kluckert, Daniela
DIE LINKE.	Vogler, Kathrin Zdebel, Hubertus	Leidig, Sabine Remmers, Ingrid
BÜNDNIS 90/DIE GRÜNEN	Hoffmann, Dr. Bettina Zickenheiner, Gerhard	Kekeritz, Uwe Strengmann-Kuhn, Dr. Wolfgang

Vor Eintritt in die Tagesordnung

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Es ist jetzt 18:00 Uhr, und ich würde dann auch unsere Beiratssitzung starten. Bevor wir in die Tagesordnung übergehen, ein paar organisatorische Hinweise: Wie Sie alle sehen, verfolgen wir die Sitzung heute wieder mittels Videoformat. Ich bitte, Wortbeiträge bzw. Wortmeldungen über die Chat-Funktion oder per Handzeichen ersichtlich zu machen, am besten natürlich über die Chat-Funktion.

Einziger Tagesordnungspunkt

Fachgespräch zum Thema „Alternative Antriebsstoffe"

dazu Sachverständige:

Jekaterina Boening
Transport & Environment's (T&E)
dazu verteilt:
Handout Ausschussdrucksache 19(26)117 (Anlage 1);
T&E Briefing „Why e-fuels in cars make no economic or environmental sense", April 2021 Ausschussdrucksache 19(26)117-1 (Anlage 2);
BloombergNEF Studie im Auftrag von T&E „Hitting the EV Inflection Point", Mai 2021 Ausschussdrucksache 19(26)117-2 (Anlage 3);
T&E Briefing "Was bedeutet eine Unterquote von 5 % E-Fuels im Straßenverkehr?", April 2021 Ausschussdrucksache 19(26)117-3 (Anlage 4)

Prof. Dr. Christopher Hebling
Fraunhofer-Institut für Solare Energiesysteme ISE
dazu verteilt:
PowerPoint-Präsentation Ausschussdrucksache 19(26)118 (Anlage 5);
Artikel „Economics & carbon dioxide avoidance cost of methanol production based on renewable hydrogen and recycled carbon dioxide – power-to-methanol" Ausschussdrucksache 19(26)118-1 (Anlage 6);
Artikel „Comparative well-to-wheel life cycle assessment of OME3–5 synfuel production via the power-to-liquid pathway†" Ausschussdrucksache 19(26)118-2 (Anlage 7);
Artikel „Energy efficiency and economic assessment of imported energy carriers based on renewable lectricity†"Ausschussdrucksache 19(26)118-3 (Anlage 8)

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Wir haben heute den einzigen Tagesordnungspunkt „Öffentliches Fachgespräch zum Thema ‚Alternative Antriebsstoffe'". Es ist ein sehr aktuelles Thema, gerade auch angesichts der CO2-Debatte. Die Mobilität ist hier ein Themenfeld, ein Sektor, der besonders herausfordernd ist auch in allen Dimensionen der nachhaltigen Entwicklung.

Ich darf unsere Gäste ganz herzlich im Namen des Beirates begrüßen; Frau Jekaterina Boening und Herr Prof. Dr. Christopher Hebling, herzlich willkommen. Wir freuen uns auf Ihren Input und Ihre Ausführungen und natürlich auch auf die Diskussion im Anschluss. Begrüßen darf ich außerdem Herrn Dr. Bauernfeind vom Bundeskanzleramt und die interessierte Öffentlichkeit.

Ich bitte alle, ihr Mikro auszuschalten, wenn Sie nicht das Wort haben – aber das ist auch bei so gut wie jedem Fall. Ansonsten besteht auch noch die Möglichkeit, dass wir das hier entsprechend bewerkstelligen. Noch ein weiterer organisatorischer Hinweis: Wir haben – Stand jetzt – etwa ab 18:45 Uhr eine namentliche Abstimmung im Deutschen Bundestag. Wir haben dann 30 Minuten Zeit für diese namentliche Abstimmung. Wir haben uns vorher drauf verständigt, dass wir um ca. 19:05 Uhr / 19:10 Uhr mit beiden Beiratssitzungen fertig sein wollen, damit wir dann nicht wieder zurückkehren müssen. Insofern brauchen wir heute tatsächlich Zeitdisziplin. Wir haben uns in der Obleuterunde auf eine Fragerunde festgelegt. Sollten wir dennoch früher mit der ersten Fragerunde fertig sein, können wir durchaus noch weitere Fragen zulassen, aber das ist eigentlich das vorgesehene Zeitkorsett.

Ich stelle kurz unsere Gäste vor. Zunächst Frau Boening: Frau Boening ist Policy Manager beim europäischen Umweltdachverband „Transport & Environment" (T&E). Sie ist Expertin für Wasserstoff und E-Fuels und koordiniert die Aktivitäten in diesen Themenbereichen. Darüber hinaus befasst sich Frau Boening mit der europäischen Klimaarchitektur, darunter natürlich auch Themen wie insbesondere die CO2-Bepreisung. In der Vergangenheit war Frau Boening beim BDI (Bundesverband der Deutschen Industrie e. V.), wo sie das Wasserstoffgremium des Verbandes leitete, sowie beim Jacques Delors Institut und beim Energieversorger E.ON. Herzlich willkommen, Frau

Boening, es freut uns, dass Sie uns heute bereichern.

Außerdem ist heute zu Gast Herr Prof. Christopher Hebling. Herr Prof. Hebling hat 1998 an der Universität Konstanz im Fach „Physik“ promoviert. Er ist seit Mai 2019 “Honorary Professor” an der University of Cape Town (Department of Chemical Engineering, Faculty of Engineering and the Built Environment). Seit 1992 ist Prof. Hebling beim Fraunhofer-Institut für Solare Energiesysteme, ISE, tätig; er ist dort Bereichsleiter „Wasserstofftechnologien“. Seit dem Jahr 2018 ist er hier zugleich Co-Direktor im Bereich „Energietechnologien und Energiesysteme“. Auch an Sie, Herr Prof. Hebling: Ganz herzlich willkommen. Über Ihren Input und über die anschließende Diskussion freuen wir uns natürlich auch.

Ein paar organisatorische Hinweise: Beide Sachverständige haben vorab Handouts übersandt, die in den entsprechenden Ausschussdrucksachen vorliegen. Wir haben uns außerdem darüber verständigt, dass wir das Gespräch aufzeichnen. Es wird auf der Webseite des Deutschen Bundestages ab Freitag zu sehen sein. Wir erstellen – wie gehabt – ein Wortprotokoll. Wir haben vorgesehen, dass die Eingangsstatements etwa zehn Minuten umfassen sollen. Sie sehen auch im Hintergrund eine entsprechende Uhr, und ich bitte Sie, auf diese Uhr zu achten und sich bei Ihren Ausführungen im Rahmen der zehn Minuten zu bewegen. Wie gesagt, um 18:50 Uhr beginnt die namentliche Abstimmung. Wir haben dann eine halbe Stunde Zeit und müssen um 19:05 Uhr die Sitzung schließen, deshalb auch keine weiteren Vorreden von mir.

Wir haben vereinbart, dass wir bei den Eingangsstatements mit Frau Boening beginnen, und ich übergebe Ihnen auch gleich das Wort. Frau Boening, wir freuen uns auf Ihre Ausführungen.

Sachverständige **Jekaterina Boening** (Transport & Environment's,T&E)): Vielen Dank, Herr Dr. Lenz und vielen Dank für die Einladung zur Sitzung heute.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Frau Boening, ich will Sie jetzt eigentlich gar nicht unterbrechen, aber wir hören Sie wieder ganz leise. Wir haben Sie vorher eigentlich ganz gut gehört. Können Sie noch einmal alle entsprechenden Einstellungen überprüfen?

Sachverständige **Jekaterina Boening** (T&E): Ich höre auch, dass jemand noch das Mikro an hat, es könnte vielleicht auch daran liegen.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Ich bitte das Sekretariat, noch einmal zu schauen, ob jeder das Mikro aus hat. Ansonsten bitte ich, dieses auszustellen.

Sachverständige **Jekaterina Boening** (T&E): Genau. Und ich werde mein Video ausschalten, weil mir angezeigt wurde, dass die Bandbreite für den Call nicht ausreicht, deshalb wundern Sie sich nicht, dass Sie mich jetzt nicht sehen.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Wir hören Sie auf jeden Fall einwandfrei.

Sachverständige **Jekaterina Boening** (T&E): Sehr gut. Noch einmal vielen Dank für die Einladung. Ich werde in meinem Vortrag ausschließlich auf das Thema „E-Fuels“ eingehen, auch wenn wir natürlich andere Alternative Antriebsstoffe haben, und ich stehe für Ihre Fragen zum Thema „Biokraftstoffe“ auch im Anschluss gerne zur Verfügung. Ich möchte insbesondere drei Aspekte beleuchten:

Erstens: Wann sind die E-Fuels nachhaltig? Zweitens: Welche Aspekte sind zusätzlich in Bezug auf die E-Fuels Importe zu beachten? Und drittens: Wo werden die E-Fuels künftig eingesetzt?

Ich möchte gerne mit dem ersten Punkt beginnen: Wann sind E-Fuels nachhaltig? Der Herstellungsprozess von E-Fuels sollte den meisten von Ihnen sehr gut bekannt sein. Im ersten Schritt wird im Prozess der Elektrolyse Wasser mittels Strom in Wasserstoff und Sauerstoff aufgeteilt. Danach benötigen wir für die Synthese zu E-Fuels auch Kohlenstoff. Für die Gewinnung von Kohlenstoff stehen uns verschiedene Optionen zur Verfügung: Wir können CO2 aus der Luft abscheiden, aber wir können natürlich auch die industriellen Stromquellen nutzen. Als Endprodukt haben wir dann nach der Synthese die E-Fuels. Das ist – wie Sie hier sehen – ein komplexer Prozess mit verschiedenen Schritten, deshalb geht in jedem Umwandlungsprozess natürlich auch Energie verloren, weshalb wir von einem Gesamtwirkungsgrad der E-Fuels von 10 bis 35 Prozent sprechen. „Gesamtwirkungsgrad“ bedeutet wirklich das, was wir ganz am Ende des Prozesses sehen, also bei der Verbrennung von E-Fuels, z. B. Verbrennungsmotor oder in einem Gasboiler. Das bedeutet zugleich, dass wir mit E-Fuels im Vergleich zur Direktelektrifizierung, also im Vergleich zu batterieelektrischen Antrieben, zwei- bis vierzehn Mal so viel Strom brauchen – diese Zahlen sind vom Potsdamer Institut für Klimaforschung. Dennoch werden wir trotz dieser Komplexität E-Fuels brauchen. Das ist auch insbesondere mit Blick auf die Klimaziele eine sehr wichtige Klimaschutzoption, und wir müssen natürlich von Anfang an die Nachhaltigkeit der E-Fuels sicherstellen. Ausschlaggebende Faktoren sind erstens, die Strombezugsquelle, und zweitens, die CO2-Quelle. Bei der Strombezugsquelle ist natürlich eines klar: Wir brauchen erneuerbaren Strom, um die E-Fuels herzustellen.

Ein wichtiges Kriterium ist dennoch auch die „Zusätzlichkeit" – zusätzliche Anlagen, die den Strom für die Herstellung von E-Fuels produzieren. Was bedeutet hier „zusätzlich"? Es gibt heute kein Land auf der Welt, das seine Energienachfrage zu 100 Prozent durch Erneuerbare Energien abdeckt. Das heißt, zum jeweiligen Zeitpunkt, wenn wir die Stromnachfrage haben, haben wir immer die fluktuierende Erneuerbaren Energien und die Residuallast. Die Residuallast, das sind die fossilen Kraftwerke. Wenn die Stromnachfrage steigt und der Bestandteil von Erneuerbaren Energien gleich bleibt, dann steigt natürlich die Residuallast und dadurch erhöht sich die CO2-Intensität des Strommixes. Weil wir – wie auf der vorherigen Folie schon gezeigt – mit E-Fuels das Stromsystem sehr stark beanspruchen, können wir natürlich davon ausgehen, dass die E-Fuels insgesamt einen negativen Klimaeffekt für das Gesamtsystem haben, wenn die „Zusätzlichkeit" nicht eingehalten wird. Deshalb bedeutet „zusätzlich" neue, nicht staatlich geförderte Anlagen. Das kann unter Umständen auch einen zusätzlichen Ausbaupfad im EEG bedeuten. Häufig wird dann die Frage gestellt: Warum wird dieses Kriterium nicht in Bezug auf die Elektromobilität gestellt? Die Antwort darauf liegt in dieser Grafik – etwas komplex –, die kommt auch vom Potsdamer Institut für Klimaforschung, sie haben erst vor wenigen Tagen ein sehr gutes Papier veröffentlicht. Sie sehen hier auf der X-Achse die CO2-Intensität des Strommixes in verschiedenen Regionen – Deutschland ist hier in der Mitte. Auf der Y-Achse ist die Berechnung für die Lebenszyklusanalyse zu CO2-Emissionen von verschiedenen Antriebsstoffen. Die Linien, die so horizontal verlaufen, das sind die fossilen Kraftstoffe, und die Linien in lila, das sind die E-Fuels. Wie Sie sehen: Mit dem deutschen Strommix emittieren die E-Fuels heute drei- bis viermal so viel CO2 wie fossile Kraftstoffe. Bei Elektromobilität – das ist die gelbe Linie hier unten – haben wir bereits mit dem heutigen Strommix in Deutschland CO2-Einsparungen und deshalb auch einen positiven Klimaeffekt, weshalb auch unterschiedliche Anforderungen an E-Fuels und an Elektromobilität gestellt werden.

Zu der CO2-Quelle möchte ich gar nicht viel sagen. Wir haben – wie gesagt – zwei Optionen: Industrielle Punktquellen wie z. B. solche tollen Projekte wie „Carbon2Chem" und die Möglichkeit mit „Direct Air Capture" (Verfahren zur Gewinnung von CO2 direkt aus der Umgebungsluft). Diese Möglichkeiten müssen skalieren, weil die industriellen Punktquellen natürlich die Emission nur halbieren und nicht komplett vermeiden. Deshalb müssen wir sicherstellen, dass wir von Beginn an auch die „Direct Air Capture" regulatorisch verankern.

Nächster Punkt: „Importe". Es wird sehr häufig suggeriert, dass wir E-Fuels importieren können und auch sollen. Das ist sicherlich eine Option, die wir brauchen, um die Klimaneutralität im Jahr 2050 oder 2045, wie das jetzt für Deutschland gilt, zu erreichen. Dennoch müssen wir mit Blick auf Importe auch die Nachhaltigkeit berücksichtigen, und hier gibt es auch weitere Aspekte. Erstens: Sie sehen auf dieser Folie den Energiemix von potenziellen Exporteuren. Marokko mit sieben Prozent Anteil Erneuerbarer Energien, Saudi-Arabien ein Prozent, Australien sechs Prozent. Der einzige wirkliche Vorreiter hier ist Chile mit 23 Prozent, hier spielt auch die Wasserkraft eine extrem wichtige Rolle. Die Frage stellt sich natürlich: Wie wollen wir die „Zusätzlichkeit" in Ländern sicherstellen, die heute in ihrem Energiemix überwiegend fossil sind? Bisher gibt es keine Antwort darauf. Natürlich ist aus Sicht der Nachhaltigkeit absolut klar, dass die E-Fuel-Produktion nicht auf Kosten der Dekarbonisierung der einheimischen Energieversorgung stattfinden darf. Es kann verschiedene Ansätze geben. Vielleicht kann die Anforderung gestellt werden, dass z. B. ein Teil der Energieanlagen der einheimischen Energieversorgung zur Verfügung stehen muss, aber natürlich kommen viele weitere Fragen dazu, wie die rechtlichen und die politischen Fragen: Wem gehören diese Anlagen? Es ist auf jeden Fall ein Aspekt, der weiter bedacht werden muss.

Zweitens: In Wüstenregionen haben wir den Wasserbedarf der Elektrolyse. Wir können natürlich nicht das Trinkwasser für die Elektrolyse nutzen, und die Entsalzungsanlagen, die dort betrieben werden, müssen mit erneuerbarem Strom angetrieben werden. Wir müssen den CO2-neutralen Transport sicherstellen, und wir brauchen ein internationales Zertifizierungssystem für „Power-to-X"-Produkte (PtX). Heute haben wir keine Transparenz darüber, wo, was, wie produziert wird, und ein solches internationales Zertifizierungssystem ist einfach die Voraussetzung dafür, dass die Importe künftig nachhaltig werden.

Last but not least: Wir haben heute keine internationalen PtX-Lieferketten und aus unserer Sicht – aus Sicht von T&E –, aber auch aus Sicht von vielen anderen Experten, ist es einfach eine sehr riskante Klimaschutz- und Industriestrategie Deutschlands, aber auch Europas insgesamt, auf dieser Vision von Importen zu bauen, insbesondere in der kurzen Frist bis 2030.

Wo werden E-Fuels künftig eingesetzt? Trotz aller Komplexität und Schwierigkeiten bei der Sicherstellung der Nachhaltigkeit: Wir werden E-Fuels in der Luftfahrt, in der Schifffahrt brauchen. Das wird auch eine große Herausforderung sein, weil wir natürlich hier auch über enorme Energiebedarfe sprechen. Für die Luft- und Schifffahrt in ganz Europa werden wir über 1.000 Terrawattstunden (TWh) erneuerbaren Strom für die Herstellung von E-Fuels benötigen, d. h., auch hier können die Importe eine wichtige Rolle spielen.

Die Industrie- und die Stahlbedarfe werde ich hier überspringen, um zu dem wichtigen Punkt zu kommen, dass die E-Fuels im Straßenverkehr einfach keine Zukunft haben. Das sage ich nicht als Vertreterin der Umweltszene, sondern das sagt der Markt. Das betrifft nicht nur den PKW-Bereich, sondern auch den LKW-Bereich. Traton, die Tochter von VW, hat erst vor Kurzem sehr deutlich gemacht, dass die Zukunft dem Elektro-LKW gehört, und wir haben gesehen, wie die Börse, wie der Markt, auf die neuen Pläne von VW, massiv in Elektromobilität einzusteigen und die Ankündigung, 70 Milliarden Euro in Elektromobilität zu investieren, reagiert hat: VW hat extrem an Wert gewonnen.

Wir haben immer noch das „Sorgenkind Bestandsflotte", auch wenn wir jetzt mit der Flottenerneuerung vorankommen. Ich möchte aber hier betonen, dass die E-Fuels auch für die Bestandsflotte keine Lösung darstellen. Diese Folie habe ich auch schon seinerzeit bei einer Anhörung gezeigt. Um fünf Prozent der Kraftstoffe mit E-Fuels im Straßenverkehr in Deutschland zu ersetzen, würden wir 15 Gigawatt Elektrolysekapazität benötigen. Das ist das Dreifache von dem, was wir in Deutschland für 2030 planen. Aus heutiger Sicht ist es schwer, sich vorzustellen, dass diese Kapazitäten woanders auf der Welt zusätzlich zu all dem, was wir im Luftverkehr, in der Industrie und in anderen Sektoren brauchen, entstehen werden.

Ich bedanke mich für Ihre Aufmerksamkeit und freue mich auf die Diskussion. Vielen Dank.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Vielen Dank. Das war fast eine Punktlandung. Danke auch für die Darstellung der Dimension der Aufgabe, die wir vor uns haben, und ich leite gleich über zu Herrn Prof. Hebling. Herr Prof. Hebling, Sie haben das Wort.

Sachverständiger **Prof. Dr. Christopher Hebling** (Fraunhofer-Institut für Solare Energiesysteme, ISE): Sie hören und sehen mich? Wunderbar. Jetzt wird mir auch klarer, wie das Podium hier besetzt ist.

Ich komme aus der gleichen Zielstellung zu anderen Ergebnissen. Zunächst einmal: Bei Fraunhofer haben wir uns letztes Jahr in einem Strategieprozess die wichtigsten Themen gesellschaftlich aufgezeichnet und sind jetzt auf sieben Forschungsfelder, die für uns von größter strategischer Bedeutung sind, gekommen – und eines davon sind die Wasserstofftechnologien, weil wir bei Fraunhofer der Überzeugung sind, dass nur mit Wasserstofftechnologien die Ziele der Nachhaltigkeit im Sinne auch einer vollständigen Kreislaufwirtschaft erreicht werden können.

Wo stehen wir? Treibhausgasemissionen – die Grafik kennen Sie, denke ich: Über die letzten 20 Jahre sind die CO2-Emissionen im Transportbereich in Deutschland mehr oder weniger konstant geblieben, und jetzt müssen wir in bis 2030 etwa eine Halbierung erreichen. Das zum einen aufgrund des Bundesverfassungsgerichtsurteils, aber wir müssen zudem auch schauen, wie wir die lokalen Schadstoffemissionen in erheblichem Maße reduzieren. „Euro 7“ ist im Anmarsch, aber auch die „CARB“ (California Air Resources Board – Emissionsschutzbehörde Kaliforniens), also die kalifornische Regulation von der Lokalemission. Das ist sozusagen die Aufgabe, die wir vor uns haben, und die ist extrem schwer zu erreichen.

Aber was gehört noch zur Ausgangslage? Wir haben inzwischen 189 Staaten, die das Pariser Abkommen ratifiziert haben, also nahezu 100 Prozent. Inzwischen sind 75 dieser Staaten auch bis 2050 der Klimaneutralität verschrieben – China bis 2060, Deutschland möglicherweise bis 2045 –, wenngleich ich nicht sicher bin, ob alle wissen, was Klimaneutralität in jetzt 25 Jahren bedeutet. Was auch interessant ist, ist, dass von inzwischen 30 Staaten im Rahmen von nationalen Strategiepapieren Wasserstoff als eine ganz massive Technologie zur Erreichung der Klimaziele formuliert wird. Wenn man alle Projekte, die unterwegs sind, aufaddiert, sind etwa 300 Milliarden Dollar für den Transport, die Verteilung und eben auch die Nutzung in den Endsektoren in der Entwicklung. Weiterhin sind in Summe im Moment 17 Gigawatt Elektrolyseure global in verschiedenen Stadien in der Entwicklung. Wir haben in unseren Szenarien Rechnungen, die wir im Fraunhofer-ISE machen die Auswirkungen der verschärften CO2-Reduktionsziele auf minus 65% quantifiziert. Sie sehen hier „Referenz 55“, d. h., das alte Ziel bis 2030 quantifiziert. Bislang war minus 55% bis 2030 bzw. minus 95% für 2050 das alte Ziel und, Sie sehen dann hier „Referenz 65“ das verschärfte Ziel (minus 65%) bis 2030, und was das für die „Power to X“-Produkte, also die synthetischen Kraftstoffe, bedeutet. Und Sie sehen hier: Allein diese Verschärfung um zehn Prozent etwa verdoppelt den Bedarf eben auch über 200 TWh an Syntheseprodukten. Wir sind sicher, dass der Bedarf an grüner Energie über den reinen Stromsektor gar nicht abgedeckt werden kann.

Wir hatten den Auftrag, für den Nationalen Wasserstoffrat auch eine „Meta-Studie Wasserstoff“ zu erstellen, bei der wir alle Studien – sowohl die europäischen, hier sehen Sie die wichtigsten europäischen Studien, aber auch hier die nationalen Studien – auswerten und ganz nüchtern einfach mal die Datenlage exzerpieren. Die meisten Kürzel kennen Sie, denke ich: BDI (Bundesverband der Deutschen Industrie e. V.), dena (Deutsche Energie-Agentur GmbH), Agora (Agora Energiewende), UBA (Umweltbundesamt), BMWi (Bundesministerium für Wirtschaft und Energie), ISE (Fraunhofer-Institut für Solare Energiesysteme), Jülich (Forschungszentrum Jülich GmbH) und NRW (Nordrhein-Westfalen). Und was man da lernt, ist sehr viel. Wir haben 150 Folien, die werden nächste Woche auch durch den Nationalen Wasserstoffrat verkündet. Wir haben – wie gesagt – einfach nur die Daten exzerpiert –, und man sieht eben, bei den „Importquoten Wasserstoff“ ist die Bandbreite jetzt 2030 etwa bei 40 bis 70 Prozent. Viele gehen allerdings auch von 0 Prozent aus, d. h., dass wir bis 2030 den Wasserstoff, den wir in den Sektoren „Mobilität“ und „Industrie“ benötigen, national herstellen, und dass sich erst dann der internationale Handel etablieren wird.

Wenn man die Syntheseprodukte anschaut, ist es naturgemäß umgekehrt. Die Importquoten werden jetzt lange erst mal sehr hoch sein – 90 bis 100 Prozent. Möglicherweise bleibt es auch auf hohem Niveau, weil die Synthesevoraussetzungen in anderen Ländern aufgrund des Zugangs zu sehr günstigen erneuerbaren Energie einfach deutlich besser sind. Aber auch dena sagt, „Import Wasserstoff- und Syntheseprodukte um die 20 Prozent in 2040, und es geht dann entsprechend hoch“. Also, das ist die Studienlage.

Es wären jetzt noch sehr viele Daten anzuschauen, aber wenn man sich hier noch den Verkehrssektor anschaut: Was alle Studien sozusagen aufeinander gestapelt ergeben, ist, dass bis 2050 etwa die reine Wasserstoffnachfrage in der Größenordnung von 20 Prozent liegen wird – das sehen Sie hier rechts – bei 100 Prozent bei Treibhausgas-Minderungsziel und weitere etwa 20 Prozent für Syntheseprodukte. Dann kommt ein bisschen Biomasse, dann hier Strom und eben fossile Brennstoffe, die werden nicht vollständig aus dem System gedrängt sein.

Schauen wir uns noch mal die Gesamtkette an: Nachhaltige Ausgangsprodukte sind natürlich die „Grünen Elektronen“ – wo auch immer Sie hergestellt werden – Wind und Solar und wohlmöglich eben auch die Wasserkraft. Wir brauchen die Luft, um Stickstoff quasi abzuspalten, 80 Prozent ist ja in der Luft. Wir brauchen aber auch immer den

Kohlenstoff für die Syntheseschritte für kohlenstoffbasierte Energieträger, und dann ist hier die effiziente Konversion – Methanol, Ammoniak, je nachdem, was man verwendet –, und hinten eben die nachhaltigen Produkte. Idealerweise nutzt man natürlich den Wasserstoff direkt als Energieträger, aber für viele Anwendungen – das wurde ja eben schon benannt – brauchen wir flüssige Energieträger, zum einen wegen der Transportfähigkeit, aber auch, um Schiffs- und Flugverkehr auch über nachhaltige Produkte erreichen zu können. Weiterhin brauchen wir aber auch einen Ersatz für die ganzen erdölbasierten Chemikalien. Auch Ammoniak muss ersetzt werden, der derzeit natürlich auch auf fossilen Quellen beruht. Das ist sozusagen das Gesamtbild, was wir in den nächsten Jahrzehnten vor uns haben.

Was haben wir für Optionen bei Kraftstoffen? Entweder wir nehmen den Wasserstoff direkt – idealerweise in Brennstoffzellen wegen der hohen Effizienz, die bei etwa 50 Prozent liegt – oder eben durch eine weitere Synthese – eben „Methanol to Gasoline“ und was sie hier alles sehen. Die Oxymethylenether-Route ist das, wo man am Ende synthetisches Diesel erzeugen kann oder „Methanol to Jet fuel“. Auch das ist sehr wichtig, um natürlich auch den Flugverkehr erreichen zu können. Die Kriterien sind „gesamthaft“; also, wir brauchen die Betrachtung zur Systemeffizienz und nicht von Einzeleffizienzen in der Wandlung, sondern das Gesamtsystem.

Hier noch einmal eine Aufstellung der 30 nationalen Wasserstoff-Roadmaps, die inzwischen entstanden sind. Es kommen jetzt in den nächsten ein, zwei Monaten noch sechs weitere dazu, beispielsweise Italien. Die Antreiber für die Strategiepapiere sind recht unterschiedlich: Klar, immer sozusagen aus Klimaschutz induziert, aber sie haben noch viele andere Gründe wie z. B. auch im Sinne der Sicherung des Industriestandortes, das ist insbesondere Deutschland, aber auch Japan und die USA. In anderen Regionen, wie beispielsweise Australien und der MENA-Region, möchte man sich für den Export erneuerbarer Energieträger aufstellen.

Um auch auf die Effizienzdebatte einzugehen: Wir haben Batteriefahrzeugen und Hybridfahrzeuge mit Verbrennungsmotoren verglichen. Das sind jetzt Ergebnisse, die noch nicht veröffentlicht sind. Um es kurz zu machen: Wir haben hier gerechnet, dass man in der kompletten Kette, also vom Beladen der Batteriefahrzeuge bis hin zum grünen Stahl für den Motor wirklich reinen Grünstrom annimmt. Wichtig ist auch, dass man die Hybridisierung der Fahrzeuge mit berücksichtigt, weil reine Verbrenner tatsächlich „Technologie von gestern“ sind. Aber über die Hybridisierung, wenn man jetzt mal – was hier der Fall ist – einen Range Extender (REEV – Reichweitenverlängerer) mit einer 25-prozentigen Nutzung von E-Fuels betrachtet, ist der Unterschied zu einem BEV400 (BEV – Battery electric vehicle – Batteriefahrzeug) etwa in der Effizienz Faktor 1,5. Noch mal: Wenn man alles auf Grünstrom basiert, was man ja in 2045 auch braucht.

Hier noch abschließend Projekte, die in der Entwicklung sind. Also, Shell bereitet sich in Wesseling vor, von derzeit zehn Megawatt Elektrolyse auf 100 Megawatt hochzugehen, um synthetische Flugkraftstoffe zu erzeugen. Das „Chile-Projekt“ – denke ich – kennen Sie, das ging gut durch die Presse, dass Porsche im nächsten Jahr 130.000 Liter E-Fuels herstellt mit dem Ziel, zwei Jahre später 55 Millionen Liter E-Fuels herzustellen, also in Tonnen eine halbe Million Tonnen, und d. h., es wird auf Methanol basiert sein.

Auch Maersk hat sich eindeutig in Richtung Synthesekraftstoffe im Nachhaltigkeitsbericht aufgestellt, da insbesondere Methanol und Ammoniak als Kraftstoffe für die Schiffe der Zukunft. Insbesondere da ist klar, dass man keine Zwischenlösungen im Sinne von LNG (Liquefied Natural Gas – Flüssiggas) mehr akzeptiert, weil das ja bekanntermaßen nicht CO2-neutral ist, sondern da gibt es eine ganz klare Priorisierung auf vollständig nachhaltige Kraftstoffe.

Abschließend: Wir müssen verstehen, dass das neue Energiesystem einen komplett anderen Charakter hat. Wir haben keine Grundlast mehr, sondern nur noch volatile Energieerzeugung. Die fossile Energie, aber insbesondere auch die Eigenschaft der Speicherung selbiger, muss ersetzt werden. Wir brauchen wasserstoffbasierte Kraftstoffe im künftigen Mix neben Batteriefahrzeugen, insbesondere in Form von den langkettigen Syntheseprodukten. Wir brauchen in der Zukunft auch Verbrennungsmotoren. Die nationale Politik muss klare Pfade vorgeben. Wir müssen Well-to-Wheel – also die Gesamtketten – betrachten und in dem

Sinne auch Unterquoten von grünen Kraftstoffen festlegen insb. auch für die Investitionssicherheit von Kapitalgebern festlegen. Wir brauchen gleichermaßen grüne Elektronen wie grüne Moleküle im Sinne der Gesamtsystemausrichtung. In dem Sinne ist klar – diese ganzen Debatten, die Sie ja auch gut kennen: Sektor-Kopplung ist ganz wichtig, um die Sektoren Wärme, Chemie, Industrie aber auch Mobilität zu erreichen. Und schließlich, ganz wichtig, und das ist eigentlich der entscheidende Punkt: Es geht nicht um Deutschland, es geht nicht mal nur um Europa, sondern wir brauchen eine globale Betrachtung für den Aufbau eines globalen erneuerbaren Energiehandels. Die Welt ist gesamthaft zu betrachten und deswegen ist es so wichtig, dass 189 Länder jetzt das COP21 ratifiziert haben. Alle Länder gehen in Richtung Klimaneutralität und bereiten sich auf einen Handel mit erneuerbaren Energieträgern vor, die in aller Regel flüssig sein werden. Ammoniak, Methanol und weitere langkettige Derivate, aber auch Flüssigwasserstoff werden im künftigen globalen Energiesystem und dem Energiehandel sehr wichtig werden

Damit möchte ich mich noch mal für die Einladung, mit Ihnen über das Thema zu diskutieren, herzlich bedanken. Vielen Dank.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Vielen Dank auch an Sie, Herr Prof. Hebling, für den Überblick. Wir haben jetzt zwei Überblicke bekommen, die doch in der Konnotation etwas unterschiedlich waren. Umso wichtiger ist natürlich auch die entsprechende Diskussion jetzt im Anschluss. Ich schaue in die Runde. Ich bitte Sie, Herr Prof. Hebling, dass Sie vielleicht noch die Präsentation schließen. Ich würde mit Abg. Peter Stein von der CDU/CSU-Fraktion beginnen.

Abg. **Peter Stein** (CDU/CSU): Erst einmal ganz herzlichen Dank. Herr Prof. Hebling, ich bin Ihnen sehr dankbar, dass Sie am Schluss die globale Überschrift noch mal gefunden haben, weil ich glaube, dass es tatsächlich das ist, was auch den „Game-Changer“ darstellt, den wir jetzt in dieser aktuellen Situation haben, dass wir es durch die Erneuerbaren Energien, durch die E-Fuels, durch die Wasserstofftechnologie mit zukünftigen potenziellen Partnern in der Welt zu tun haben, die bisher in der globalen Energieversorgung nicht am Tisch gesessen haben, zumindest nicht in der ersten Reihe. Ich glaube, das zeigt dann auch die strategische Dimension, die dahintersteckt, wenn wir uns jetzt zu bestimmten Technologien bekennen und auch in Investitionen gehen.

Da würde ich an einer Stelle direkt mal Frau Boening widersprechen. Ich sehe es nicht als sinnvoll an, dass wir jetzt auf die „Zusätzlichkeit“ einer Verfügbarkeit von Energie warten. Ich meine, das kann vielleicht Saudi-Arabien liefern, mit seinem wirtschaftlichen Potenzial innerhalb einer kurzen Zeit enorme Kapazitäten hochzufahren, um sich a) selbst zu versorgen und dann auch b) noch Exporteur zu sein, aber schon bei Chile oder Marokko wage ich mal die Behauptung: Ohne dass man es von Anfang an auch zeitgleich mit Exporten von Energieträgern zu tun hat, wird niemand investieren und die Länder werden technologisch und wirtschaftlich nicht in der Lage sein, sich selbst zu versorgen, wenn nicht parallel von außen auch Investitionen in den Energiesektor getätigt werden. Das muss – glaube ich – auf jeden Fall zusammengedacht werden. Und wenn wir bei Investitionen sind: Da ist eigentlich etwas – glaube ich –, was wir auch national intensiver betrachten müssen. Sie haben vom „Sorgenkind Bestandsflotte“ gesprochen. Diese Bestandsflotte baut sich ja jetzt heute und auch in den nächsten Jahren noch auf. Und wenn wir jetzt das Ziel haben, bis 2045 im Weitesten CO2-neutral zu werden, auch im Mobilitätsbereich, dann müssen wir spätestens in den nächsten vier Jahren aufhören, mit Verbrennern zu arbeiten, sondern spätestens in vier Jahren muss jedes dann gekaufte Auto, jeder Bus, jeder LKW, jedes Schiff und auch jedes Flugzeug im Grunde in der Lage sein, mit CO2-neutralen Brennstoffen gefahren zu werden. Das sind eigentlich die Herausforderungen; das ist diese Zeitschiene. Ich glaube, wir haben nicht die technologische Herausforderung, auch nicht unbedingt eine Willensherausforderung, wir haben tatsächlich eine große Herausforderung in der Zeitschiene, und da stecken wir global an dieser Stelle alle unter der gleichen Decke, also geht das nur zusammen. Da wäre meine erste Frage an Herrn Prof. Hebling: Wo sehen Sie Deutschland da? Sind wir mehr im investiven Bereich gefragt, sind wir mehr im technologischen Bereich gefragt? In der Zielstellung, dass wir selber CO2-neutral werden wollen, aber das eben nur in Partnerschaft geht: Wo würden Sie da die Schwerpunkte setzen? Wo sollte Deutschland am stärksten das Gewicht einbringen? Das an der Stelle.

Das Zweite, was ich mir wünschen würde und was wir – glaube ich – auch als Politik brauchen: Wir brauchen Empfehlungen von Ihnen. Also nicht – ich sage einmal – ein Darstellen dessen, was alles nicht getan werden darf, und nicht ein Darstellen dessen, was alles funktioniert oder nicht funktioniert, sondern im Grunde brauchen wir dringend – ich habe von den nächsten vier Jahren gesprochen – Hilfestellung, Empfehlungen, worein zu investieren ist, in welcher Reihenfolge, in welcher Priorität und wo die Schwerpunkte zu setzen sind. Ich nehme mal nur als Beispiel den öffentlichen Nahverkehr. Wir haben gerade bei mir im Landkreis den ersten Wasserstoff-Testbus in Betrieb genommen. Auch dort gilt: Die Busse, die in den nächsten vier Jahren gekauft werden, sind danach noch 20 Jahre am Markt. Das hilft uns dann in 20 oder 25 Jahren nicht, wenn die immer noch fahren, um die Bilanz herunterzukriegen. Also entweder muss ich dann auch Busse haben, die dann – heute Verbrenner – zukünftig mit E-Fuels gefahren werden können. Da bin ich ganz bei Herrn Hebling, zu sagen, wir brauchen E-Fuels im Markt, einfach, um mit dem Bestand umzugehen. Ich will jetzt gar nicht von Einsatzfahrzeugen – wie Feuerwehren – reden usw., die ja auch alle betrieben werden müssen.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Ich bitte, etwas auf die Zeit zu achten.

Abg. **Peter Stein** (CDU/CSU): Deshalb meine letzte Frage an Frau Boening noch mal: Wo würden Sie uns Empfehlungen geben, um einfach aus Ihrer Sicht in der Zeitschiene bleiben zu können?

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Vielen Dank. Als Nächstes Michael Thews von der SPD-Fraktion. Wir haben Probleme – glaube ich –, dass die Frau Boening gerade aus der Leitung geflogen ist, insofern bitte ich, gleich mit den Fragen an Herrn Prof. Hebling beginnen.

Sachverständige **Jekaterina Boening** (T&E): Nein, ich bin schon da.

Abg. **Michael Thews** (SPD): Umso besser. Ich würde Frau Boening noch mal die Chance geben, über diese – ich sage es jetzt mal – „Verdrängung“ zu reden. Sie hat ja gesagt, im Grunde genommen müssen auch die Länder, aus denen wir importieren wollen, erst einmal selber versorgt werden. Das haben wir z. B. auch im Umweltausschuss diskutiert als wir in Marokko waren und uns dort die Photovoltaikanlage angeschaut haben. Soweit ich weiß, wird der Strom, der da produziert wird – das ist eine riesen Anlage mit 400 / 500 MB –, erst einmal da gebraucht; er wird gar nicht exportiert. Da sind wir noch lange nicht. Ich kann mich auch sehr gut daran erinnern, dass Hermann Scheer, als er sein Buch geschrieben hat, darauf hingewiesen hat, dass, wenn wir regenative Energiemodelle entwickeln, wir auch darauf achten müssen, dass die Energie, die dann noch von Primärrohstoffen genutzt wird, nicht einfach nur in andere Länder verdrängt wird, weil sie dann billiger wird und von anderen Ländern stärker genutzt wird. Das würde in der Bilanz dem CO2 gar nichts nützen. Also insofern – glaube ich – muss man das schon beachten. Ich würde Frau Boening gerne noch mal die Chance geben, das zu erläutern.

Dann ist es tatsächlich so – ich habe das mal berechnen lassen, was das bedeutet, wenn wir auf E-Fuels gehen würden: Die sind ja von der Effektivität unglaublich niedrig. Man müsste unglaublich viel Strom produzieren, um E-Fuels herzustellen. Das kann ja bestenfalls – sage ich mal – ein Produkt für Antriebssysteme sein, wo man wirklich keine Alternative hat. Da frage ich mich natürlich – also beim Fliegen, okay, da weiß ich es nicht, aber bei Schiffen oder anderen Dingen –, ob wir uns dann nicht eigentlich viel stärker die Antriebstechnologien anschauen und fragen müssten, „Wie kriegen wir die in eine effektive Schiene?“. Effektiv ist für mich momentan Batterieantrieb und Wasserstofftechnologie – anstatt zu überlegen, wie wir jetzt auf Biegen und Brechen so viel Energie produzieren, dass wir E-Fuels herstellen können. Ist das nicht eigentlich der falsche Weg? Müsste man da nicht eigentlich einen ganz anderen Weg gehen? Das wäre meine Frage. Vielen Dank erst mal.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Vielen Dank. Als Nächstes Dr. Rainer Kraft von der AfD.

Abg. **Dr. Rainer Kraft** (AfD): Vielen Dank. Ich würde Frau Boening kurz fragen. Es war ein recht interessanter Vortrag. Ich stimme Ihnen komplett zu, dass der Wirkungsgrad für E-Fuels bei 10 bis 35 Prozent liegt, aber in der gleichen Größenordnung liegt er für Wasserstoff. Für mich als Chemiker ist Power-to-X genau das Gleiche.

Ob ich jetzt daraus einen kohlenstoffbasierten Flüssigkraftstoff herstelle oder Wasserstoff, das ist für mich „gehupft wie gesprungen“. Ich kann deswegen Ihre Bewunderung für Wasserstoff und die Ablehnung von flüssigen Treibstoffen und Kraftstoffen nicht ganz verstehen. Zu Recht weisen Sie darauf hin, dass PtX-Lieferketten unter Klimaschutz- und Industriestrategien riskant sind, aber das Gleiche trifft ja auch für Wasserstoff zu. Und wenn ich einmal das BMWi (Bundesministeriums für Wirtschaft und Energie) zitieren darf, das geht ja davon aus, dass wir in Zukunft 90 Prozent unseres Wasserstoffes aus den Gegenden des Nahen und Mittleren Ostens und Afrika importieren wollen. Wenn Ihre Aussage für „Power-to-X“-Flüssigkraftstoffe – Syn-Fuels – gilt, dann gilt sie selbstverständlich auch für Wasserstoff. Es kann also in dieser Beziehung kein Argument sein, dass wir das machen. Der große Vorteil von einem synthetischen Kraftstoff liegt darin, dass er logistisch viel leichter handhabbar ist als der ganze Wasserstoff. Wasserstoff hat eine extrem geringe Energiedichte. Das stellt logistisch eine riesige Herausforderung dar. Es wird schwierig, überhaupt ein Schiff zu konzipieren, das Netto-Energie transportieren kann, weil der Wasserstoff nämlich so eine geringe Energiedichte hat, dass ein Tanker große Probleme hat, Netto-Energie zu transportieren, wenn ich die Energie zum Transport davon abziehe. Wo ist der Unterschied für Sie, dass Sie einer Syn-Fuel-Strategie – Power-to-X zu flüssigen Kraftstoffen – hier Risiken bescheinigen, während Sie gleichzeitig sagen, eine Wasserstoffproduktion aus genau den gleichen Gegenden der Welt wäre wünschenswert und würde kein Problem darstellen? Danke.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Vielen Dank. Als Nächstes Herr Dr. Lukas Köhler von der FDP.

Abg. **Dr. Lukas Köhler** (FDP): Herzlichen Dank erst einmal an beide Vortragenden. Ein super spannendes Thema, eine super interessante Diskussion. Herr Hebling, Sie haben – finde ich – viele extrem gute, wissenschaftlich fundierte – aus der Studie ja scheinbar – Sachen gesagt, die ich extrem spannend fand. Vor allem auch diesen Effizienzvergleich, der auch so ein bisschen die Argumente von vorher ausgehebelt hat. Das fand ich also sehr, sehr spannend. Ich habe nun zwei Fragen dazu. Das eine: Sie sagten, die Studie kommt erst noch, oder war das eine jetzt schon veröffentlichte Studie? Ich habe sie auf die Schnelle jetzt nicht gefunden, aber vielleicht war ich auch nicht schnell genug im Suchen.

Sachverständiger **Prof. Dr. Christopher Hebling** (Fraunhofer-Institut für Solare Energiesysteme ISE): Vielleicht darf ich gerade, weil es schnell geht, sagen: Das haben wir für den Nationalen Wasserstoffrat erstellt. Das wird diese Woche redigiert, sowohl die 60 Seiten als auch die 150 Folien, und soll dann eigentlich nächste Woche hochgeladen werden.

Abg. **Dr. Lukas Köhler** (FDP): Ja, dann sage ich dazu noch nichts. Aber dann ist gut, dann freue ich mich darauf. Wenn die kommen, dann schaue ich mir das mal näher an. Super spannend.

Die zweite Frage: Sie haben den Schiffssektor erwähnt. Ich habe das jetzt auch gehört, dass die sozusagen den Sprung gar nicht mehr über „LNG“ machen, sondern sofort in E-Fuels einsteigen. Wie sehen Sie denn die Skalenpotenziale von E-Fuels? Ich meine, dass ineffizienteste Energieprodukt, das wir jemals hatten, waren Erneuerbare. Also, Wind- und Solarenergie waren ja am Anfang unglaublich ineffizient, bis man sie über die Skaleneffekte, über die Entwicklung, immer weiter verbessert hat. Die haben riesige Summen reininvestiert. Anscheinend ist die Schiffsindustrie, so wie Sie das gerade ausgeführt haben, ja auch dazu bereit, riesige Summen zu investieren, und das würde mich zumindest interessierten.

Frau Boening, zu Ihnen würde ich gerne auch noch kommen und drei Fragen stellen. Das Erste ist allerdings eine kurze Vorabbemerkung: Mit ihrer Rechnung bin ich extrem überrascht, dass Transport & Environment's gegen Bahnverkehr ist, dass Sie also sagen, Bahnverkehr ist nicht sinnvoll nachhaltig nutzbar. Weil, die Rechnung – –

Sachverständige **Jekaterina Boening** (T&E): Ich glaube, ich habe nie etwas zum Bahnverkehr gesagt.

Abg. **Dr. Lukas Köhler** (FDP): Ja, warten Sie mal. Ich habe doch auch nicht reingelabert. Die Fragestellung, die Sie gerade aufgemacht haben, bedeutet doch: Wenn ich „Zusätzlichkeit“ habe und dafür sorge, dass dann z. B. Diesel oder mehr CO2-basierte Dinge verbrannt werden, ich das dann nicht als „nachhaltig“ bezeichnen kann. Wenn ich jetzt aber den Bahnverkehr massiv erhöhen würde, würde das ja z. B. zu einer höheren Nutzung von – aktuell – „Datteln 4“ führen, d. h. also, mehr Kohlestrom würde dafür ausgestoßen werden, und damit wären wir in dem gleichen Argumentationsmuster wie zu den E-Fuels. Genauso wie die Frage der weiteren Nutzung von dieselbasierten Strecken. Natürlich haben Sie aktuell beim Bahnverkehr, zumindest im Bahnmix, immer noch Strecken, die Sie auf Diesel fahren müssten, und damit würde ja das auch nicht funktionieren. Ich nehme mal an, dass Sie die Gegenargumentation aufmachen würden, zu sagen „Na ja, weil im Moment laut der PtX-Studie – zumindest bei dem, was beim Ausstoß hinten herauskommt – die Effizienz höher ist, kann man sagen, okay, aktuell kann man E-Fuels im Strommix nicht verwenden, aber E-Mobilität.“ Das ist zwar eine Ungleichbehandlung, kann man aber noch so argumentieren. Aber zumindest im Bahnbereich müsste man ja dann sagen „Bahn ist nicht effizient“. Dass kann ich mir nicht vorstellen, dass das Ihre Argumentationskette ist. Können Sie mich hier aufklären? Und ansonsten würde ich noch mal die Frage stellen wollen, wie viele Fahrzeuge wir weltweit aktuell mit Batterieelektrik betreiben können und wie schnell wir da umsteigen können.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Vielen Dank. Viele Fragen und auch schon eine intensive Diskussion. Ich bitte – wie gesagt –, die Fragen zu stellen und dann die Antworten zu geben, und wir fahren gleich fort mit Herrn Zdebel von den LINKEN.

Abg. **Hubertus Zdebel** (DIE LINKE.): Ja, herzlichen Dank, Herr Vorsitzender. Herzlichen Dank auch an die beiden Vortragenden. Ich fand das, was Sie gesagt haben, auch sehr aufschlussreich und spannend. Meine zwei Fragen gehen eigentlich an beide.

Die erste Frage, die ich hätte, wäre zur Zukunft der E-Fuels. Insbesondere Sie, Frau Boening, haben ja den E-Fuels im Straßenverkehr nun eher geringe Zukunftsaussichten quasi vorhergesagt oder prognostiziert. Sie haben sogar davon gesprochen, dass der Markt das ähnlich sieht. Und ich weiß, dass der Verkehrsclub Deutschland – also der VCD –, der ja Mitglied in Ihrer Organisation Transport & Environment's ist, eine deutliche Verlagerung des Verkehrs auf den ÖPNV (Öffentlicher Personennahverkehr) fordert. Der ÖPNV ist ja gerade insbesondere von Herrn Dr. Köhler schon einmal angesprochen worden. Wie sollte Ihrer Meinung nach denn dort der künftige Antrieb aussehen, und welche Rahmenbedingungen sollte die Politik hier schaffen, um tatsächlich auch zu einer stärkeren Verlagerung hin zum ÖPNV zu kommen? Das geht ein bisschen auch in dieselbe Richtung, wie Herr Thews und Herr Köhler gerade gefragt haben.

Und dann habe ich noch eine Frage an beide zur Neuzulassung von Autos mit Verbrennungsmotor. Müsste man dann nicht spätestens im Jahre 2030 vor dem Hintergrund des Ganzen zu dem Ergebnis kommen, dass Autos mit Verbrennungsmotoren dann nicht mehr zugelassen werden könnten und beendet werden müsste – auch vor dem Hintergrund der voll-elektrischen Antriebe, die ja im Vergleich zu allen anderen Varianten in den kommen Jahren eher als effektiv zu sehen sind? Und vor dem Hintergrund auch die Frage, ob es da nicht eben auch von Seiten der Politik klarer ordnungspolitischer Maßnahmen bedarf, um diese Ziele überhaupt durchzusetzen – auch vor dem Hintergrund der ökonomisch, ökologischen, aber auch sozialen Entwicklungen in unserem Land. Herzlichen Dank.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Vielen Dank Herr Zdebel und abschließend von den GRÜNEN, Herr Abg. Zickenheiner.

Abg. **Gerhard Zickenheiner** (BÜNDNIS 90/DIE GRÜNEN): Ja, Danke, Herr Vorsitzender, und Danke an beide Referenten. Es war hochinteressant. Ich bin aber nicht Ihrer Ansicht, Herr Hebling, dass es so kontradiktiv war, was Sie beide berichtet haben; es war eher eine andere Blickrichtung. Sie haben im Wesentlichen analysiert, was wir so alles brauchen können, und Frau Boening hat im Wesentlichen analysiert, wo es schwierig wird, das zu bekommen. Ich fand das eine ganz interessante Perspektive, und ich glaube, wir müssen das irgendwie zusammenführen, weil das eine nur mit dem anderen funktioniert.

In dem Zusammenhang an Sie, Herr Hebling, die erste Frage. Sie haben die Karte gezeigt mit diesen 30 Wasserstoff-Roadmaps. Hat irgendjemand einmal diese Roadmaps zusammengezählt und geschaut, was wir uns weltweit denn so an Wasserstoff wünschen, und abgeglichen, ob das mit den planetaren Grenzen machbar ist? Das wäre die Frage an Sie.

Die Frage an Frau Boening ist ein bisschen komplexer. Der Grundsatzentwurf der Bundesregierung zur Weiterentwicklung der Treibhausminderungsquote öffnet unserer Ansicht nach Tür und Tor, dass diese E-Fuels in irgendeiner Form kommen, und dass man sich da eigentlich von der Vorstellung löst, man müsse auf Elektro kommen, was natürlich einfach einen ganz großen Problemkreis mit sich bringt, in dem, was Sie analysiert haben, nämlich dass wir etwa die sechsfache Energie brauchen, um ein E-Fuel-Auto vorwärts zu bewegen wie ein elektrisches. Das dockt natürlich auch an die Frage, die ich Herrn Hebling gestellt habe, an. Gibt es Berechnungen oder Überlegungen Ihrerseits, wenn man das tatsächlich zulässt und Tür und Tor geöffnet wird und es in irgendeiner Weise verfängt, wie wir da am Schluss noch die Energiesicherheit in Deutschland gewährleisten können? Das ist meine erste Frage.

Die zweite Frage ist: Wie gehen wir damit um? Wir haben jetzt jede Menge von diesen Zulieferern, gerade MAHLE z. B., ihres Zeichens Ventilhersteller, die sich jetzt nicht vorstellen können, wie sie die im Elektromotor unterbringen. Wie gehen wir damit um, dass die immer wieder nach diesen wasserstoffbasierenden E-Fuels fragen, dass da eine Technologieoffenheit eingefordert wird, obwohl doch eigentlich längst klar ist, dass das Vorgehen höchst unwirtschaftlich ist? Sollten wir den Tankstellenbesitzern und ähnlichen Leuten nicht tatsächlich reinen Wein einschenken und klarmachen, dass man da auf einer Abschuss-Technologie sitzt und sich frühzeitig zum Umdenken bewegt? Ist es da nicht allerhöchste Zeit, um eben nicht in das Dilemma reinzulaufen, dass wir am Schluss einen immensen Überhang an klassischen Automobilen mit fossilbetriebenen Motoren rumstehen haben? Danke dafür.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Vielen Dank für die vielen spannenden Fragen. Ob wir bei den Antworten auch tatsächlich in einer übereinstimmenden Art und Weise zusammenkommen, das werden wir jetzt sehen. Ich würde jetzt Frau Boening das Wort für die erste Antwortrunde geben, und Sie bitten, dass Sie sich bei der Antwort in einem Rahmen von höchstens sechs bis acht Minuten bewegen. Wir haben eben gesagt, dass wir um ca. 19:05 Uhr diese Runde schließen müssen. Wir müssen dann schauen, ob in Anbetracht der Zeit noch eine oder einzelne Rückfragen zulässig sind. Aber zunächst zu den Antworten, Frau Boening, Sie haben das Wort.

Sachverständige **Jekaterina Boening** (T&E): Vielen Dank. Ich bleibe wegen der Bandbreite bei der ausgeschalteten Kamera.

Ich möchte mit der Frage von Herrn Thews zur „Verdrängung“ beginnen, Marokko und wie wir die Transformation der Energiesysteme in Ländern wie Marokko sehen. Das ist absolut richtig, und ich stimme Ihnen hundertprozentig zu, dass Länder wie Marokko, Saudi-Arabien, Chile und Australien natürlich die grünen Elektronen brauchen, um ihre eigenen Energiesysteme zu dekarbonisieren. Es gibt aber noch einen weiteren Punkt, der in der Debatte eigentlich fast immer vernachlässigt wird: Sie haben auch andere industriepolitische Pläne, was sie mit diesem grünen Strom vorhaben. So hatte ich z. B. erst vor wenigen Monaten das Vergnügen, bei einer Veranstaltung der Konrad-Adenauer-Stiftung dabei zu sein. Dort waren Vertreter der MENA-Region geladen, und die Vertreter der marokkanischen Regierung sprachen davon, dass sie den grünen Wasserstoff für ihre eigene Stahlproduktion nutzen wollen. Sie wollen ihre eigene Stahlproduktion aufbauen und haben kein Interesse daran, den grünen Wasserstoff nach Deutschland oder nach Europa zu schiffen, und das wird einfach nicht mitgedacht. Genau das Gleiche gilt für Australien. Auch die Australier denken an die eigene Stahlproduktion, an die chemische Produktion. Das heißt, wir können als Europäer nicht davon ausgehen, dass uns einfach die ganze Welt zur Verfügung steht und diese Länder darauf warten, dass wir da hingehen, um dort E-Fuels zu produzieren um diese E-Fuels dann in unseren Autos auf der Straße zu verbrennen.

Die Frage von Herrn Abg. Stein habe ich leider ein bisschen verpasst, weil ich Probleme mit der Verbindung hatte. Aber Sie sagten, Sie können es nicht nachvollziehen, Sie finden es nicht sinnvoll, dass der Strom „zusätzlich“ ist. Ich kann dazu nur sagen: Es geht gar nicht um sinnvoll oder nicht, sondern um die – –

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Frau Boening, ich bitte Sie, kurz zu stoppen, weil wir gerade eine Durchsage zum Beginn der namentlichen Abstimmung haben. – – Alles klar, Frau Boening, Sie können gerne fortfahren; wir liegen in unserem Zeitplan.

Sachverständige **Jekaterina Boening** (T&E): Gerne. Vielen Dank.
Herr Stein, Sie sagten, Sie finden es nicht sinnvoll, auf die „Zusätzlichkeit“ bei der Stromerzeugung für E-Fuels zu schauen. Es geht mir gar nicht um das Sinnvolle oder nicht Sinnvolle. Es geht mir einfach nur um diese Grafik, die ich Ihnen gezeigt habe, dass E-Fuels mit dem heutigen Strommix drei- bis viermal so viel CO2 im Vergleich zu fossilen Kraftstoffen emittieren. Wenn Sie der Meinung sind, dass es sozusagen okay ist, dass wir dann mit diesen Kraftstoffen sogar noch mehr CO2 im System haben, als wir ohne diese Kraftstoffe hätten, dann kann man damit leben, aber das ist dann Ihre politische Entscheidung. Es geht hier nicht um das Sinnvolle oder nicht. Ich verstehe natürlich Ihr Dilemma: Was machen wir jetzt bis 2030?. Welche Maßnahmen können wir bis 2030 priorisieren? Hier kann ich nur sagen, das ist die Flottenerneuerung mit Unterstützung von europäischen Grenzwerten und auch eine Anpassung der Dienstwagenbesteuerung und alles, was zu einer echten Mobilitätswende gehört. Wir haben von vielen heute auch das Wort „ÖPNV“ gehört, mit der Verlagerung, aber nicht nur. Dazu gehören auch bessere Mobilitätsangebote, auch ein Ausbau von Carsharing, und dass wir die Mobilitätswende ganzheitlich denken. Das gehört nicht nur zu den Forderungen von Umweltverbänden, das gehört auch zu dem Programm von Agora Verkehrswende. Wir können nicht davon ausgehen, dass wir die Verkehrswende dadurch schaffen, dass wir 48 Millionen Fahrzeuge, die wir heute auf der Straße haben, einfach im Jahr 2030 elektrifizieren. Das ist nicht das Ziel einer Verkehrswende.

Herr Köhler, auf Ihre Frage werde ich gar nicht eingehen. Ich glaube, als Abgeordneter des Deutschen Bundestages haben Sie es gar nicht nötig, einer Sachverständigen zu sagen, dass Sie „labert“. Deshalb werde ich das überspringen.

Herr Kraft, Sie haben gesagt, ich hätte Wasserstoff und E-Fuels irgendwie gleich behandelt. Es kann sein, dass Sie mich missverstanden haben. Ich habe in meinem Vortrag eigentlich nur über E-Fuels gesprochen. Bei der direkten Nutzung von Wasserstoff mit Brennstoffzelle haben Sie auf jeden Fall höhere Wirkungsgrade. Wasserstoff mit Brennstoffzelle ist im Vergleich zu E-Fuels eine effizientere Technologie. Das Problem, was wir allerdings heute haben, ist, dass wir keine Fahrzeuge mit Brennstoffzellen haben. Es gibt viele verschiedene Ankündigungen. Wir wissen von Daimler, die überlegen sich, auch Brennstoffzellen-LKWs auf den Markt zu bringen, allerdings nicht jetzt, sondern erst Ende der 2020er-Jahre. Wenn diese Fahrzeuge kommen, kann das natürlich ein „Win-win“ auch für die Zulieferer sein, weil die Zulieferer vielleicht auch eine ganz andere Rolle hätten, wenn wir im Verkehrssektor auch diese Möglichkeit hätten, auch mit der Brennstoffzelle zu arbeiten. Das Problem ist: Diese Fahrzeuge kommen nicht, und deshalb ist es riskant darauf zu warten und darauf die Mobilitätsstrategie, die Klimapolitik im Verkehrssektor, zu bauen.

Dann die Frage zum „ÖPNV“. Welchen Antrieb sehe ich im Bereich des Öffentlichen Nahverkehrs? Das wird wahrscheinlich ein Mix sein, weil wir bei den Bussen schon jetzt eine sehr, sehr gute Entwicklung sehen, dass es Elektrobusse sein werden. In vielen Städten – sowohl in Berlin, aber auch in anderen europäischen Städten, in Amsterdam – geht es sehr stark und gut voran, dass wir bei den Bussen auf Elektroantriebe umsteigen. Im Bahnverkehr – und dann doch noch die Frage von Herrn Köhler: Natürlich kann auch Wasserstoff für die nicht elektrifizierten Bahnstrecken eine Rolle spielen. Das muss man jetzt einfach hier so sagen, weil das eine Option ist.

Sie haben auch gefragt, welcher regulatorische Rahmen das unterstützen könnte, bis wir die Verlagerung haben. Wir haben das Mobilitätsgesetz, das ist auch etwas, was der VCD, unsere Mitgliedsorganisation, eng verfolgt, und das Mobilitätsgesetz kann insgesamt einfach einen sehr konstruktiven Beitrag dazu leisten, dass wir in einer gesamtheitlichen Mobilitätswende vorankommen.

Es gab auch noch die Frage zum Ausstieg aus dem Verbrennungsmotor. Ich kann dazu nur sagen: Ja, wir unterstützen es, und wir unterstützen es nicht nur aus Klima- und Umweltaspekten, sondern so eine politische Entscheidung würde Investitionssicherheit für die Industrie geben, sowohl für die

Automobilhersteller, für die Ladeinfrastrukturbetreiber als auch für die Zulieferer. Die Zulieferer stecken derzeit natürlich in einer wirklich schwierigen Situation. Sie verstehen, dass ihr Geschäftsmodell ausläuft, sie brauchen neue Geschäftsmodelle, sie müssen sich wandeln, aber die E-Fuels und das Warten auf die E-Fuels aus dem Ausland, irgendwann und in irgendwelchen Mengen, wird nicht das sein, was die Arbeitsplätze in der Zuliefererindustrie sichert. Die Zuliefererindustrien müssten jetzt schauen, wie sie in die Softwareentwicklung investieren, wie sie vielleicht doch in die Batteriefertigung einsteigen, wie sie ins Batteriemanagement einsteigen. Das neue Auto erfordert ganz andere Zulieferer. Die deutschen Zulieferer haben die Möglichkeit, das zu werden, aber das Warten auf die E-Fuels ist nicht die Strategie, die die Arbeitsplätze in Deutschland sichern kann.

Letzte Frage noch zu E-Fuels und der Energiesicherheit, sozusagen, was passieren würde, wenn wir jetzt alle Kraftstoffe auf E-Fuels umstellen würden. Ich möchte dazu keine eindeutige Aussage treffen, weil natürlich viel davon abhängt, welche Ausbauphase die Regierung verfolgt, welche Technologien ausgestoßen werden, wie schnell wir z. B. aus der Kohle aussteigen. Wenn man jetzt natürlich wieder alle Energieträger erlauben und zulassen würde, dann könnte man vielleicht auch mit E-Fuels alles machen, aber welchen Klimaeffekt hätte das? Mit den Ausbaupfaden, die wir haben, mit den Ausbaupfaden im novellierten EEG (Erneuerbare-Energien-Gesetz), werden wir sicherlich den deutschen Verkehrssektor nicht mit E-Fuels versorgen können. Es wäre dann wahrscheinlich keine gute Entscheidung, das auf Kosten der Energiesicherheit zu machen. Ja, vielen Dank.

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Vielen Dank, Frau Boening. Eine kurze Bemerkung: Es ist eine gute Debatte, eine sehr emotionale Debatte, auch eine sehr intensiv geführte Debatte. Trotzdem bitte ich natürlich alle Teilnehmerinnen und Teilnehmer, auf der Sachebene zu bleiben. Ich bin mir aber sicher, dass keine Bemerkung, die vielleicht im Eifer des Gefechts fiel, in irgendeiner Weise böse gemeint war. In dem Sinne hat jetzt Herr Prof. Hebling das Wort. Wir freuen uns auf Ihre Ausführungen.

Sachverständiger **Prof. Dr. Christopher Hebling** (Fraunhofer-Institut für Solare Energiesysteme ISE): Ja, vielen Dank. Zunächst einmal: Es gibt nicht „die“ eine Lösung. Die Lösung ist weder, alles mit E-Fuels, noch alles mit Batterien zu machen, sondern wir brauchen alle Lösungen, die technisch möglich sind. Wir müssen in alle Richtungen investieren. Ich sage deswegen vielleicht das Plädoyer „Stärker in die E-Fuels“, weil wir nach wie vor Verbrennungsfahrzeuge im Markt haben. Und noch mal: Es ist kein deutsches Problem, was wir hier adressieren. Wir haben weit über anderthalb Milliarden Fahrzeuge mit Verbrennungsmotoren global auf den Straßen, die alle mit fossilen Kraftstoffen unterwegs sind, und wir müssen den Übergang in eine nachhaltige Energiewende auch im Bereich der Verbrennungsmotorik hinkriegen. Nicht der Verbrennungsmotor ist das Problem, sondern der fossile Kraftstoff. Ich bin mir sicher, dass wir noch das ganze Jahrhundert mit Verbrennungsmotoren unterwegs sein werden. Ich halte gar nichts von Verboten von irgendeiner Technologie. Das wäre so eine Art „kalte Enteignung“ von Fahrzeugen, die heute noch gekauft werden und die dann irgendwann einfach keinen Nachschub mehr bekommen.

Gleich zu den Fragen, also: Wo sollte Deutschland aktiv werden? Ich denke, sehr stark im Technologiebereich. Wir haben in Deutschland eine fantastische Technologiebasis, die Investitionen kommen von anderorts. Ich war vor zwei Wochen in Dubai auf einer Investorenkonferenz für die MENA-Region, und man glaubt gar nicht, was für eine Investitionswilligkeit im Bereich „Wasserstoff und Wasserstofftechnologien“ – alles noch mal der nächste Schritt nach den reinen PV- (Photovoltaik) und Windinvestitionen – vorherrscht. Neom z. B. – in Saudi-Arabien – wird jetzt eine erste Investition von fünf Milliarden Dollar getätigt. Dort werden 2,2 Gigawatt Elektrolyse, kombiniert mit 2.5 Gigawatt Photovoltaik und 1.5 Gigawatt Windkraft aufgebaut. Übrigens wird Thyssenkrupp den Zuschlag bekommen, eine deutsche Technologie, wenn man so will. Dort wird Ammoniak hergestellt werden, ein Teil dieses Wasserstoffs wird also in Form von Ammoniak per Schiff nach Rotterdam gebracht werden. Wir müssen eben auch sehen, dass es ein europäisches Verteilthema ist, was da dran hängt. Rotterdam ist jetzt schon für den Import und die Verteilung von

13 Prozent aller Energieträger für Europa zuständig – Öl, Gas und Kohle –, und auch dort richtet man sich jetzt für nachhaltige Energieträger ein, die dann von irgendwo aus der Welt kommen werden. Vielleicht, weil es genannt wurde, „Australien“: Ich hatte hier letzte Woche eine Veranstaltung „Freiburg-Energie-Talk“ mit Staatssekretär Lukas vom BMBF, mit Thorsten Herdan vom BMWI, Klaus Bonhof vom BMVI und wichtigen Vertretern aus der Industrie und Verbänden und übrigens war auch der australische Botschafter Philip Green wegen des Wasserstoff-themas zugegen. Natürlich stellt sich Australien für den Export nachhaltiger Energieträger auf. In Headland werden 15 Gigawatt PV-Wind gerade für die Wasserstoffproduktion, für die Erzeugung von Ammoniak und Methanol, aufgebaut. Hauptabnehmer am Markt – und wenn wir lange noch so rumkaspern, wie wir es derzeit machen –ist Japan, ist Südkorea, aber auch China. Gigantische Mengen synthetischer Energieträger werden dort sozusagen in die konventionelle Schifffahrtsinfrastruktur überführt – übrigens auch das Thema „Schiffstransport von flüssigem Wasserstoff“. Klar, Wasserstoff wird flüssig transportiert und nicht unkomprimiert oder so was. Kawasaki baut derzeit ein Schiff für 11.500 Tonnen flüssigen Wasserstoff. Das wird in 2025 fertiggestellt sein. Das Schiff mit einem Drittel dieser Kapazität ist jetzt schon unterwegs zwischen Kobe und Melbourn.

Also, wo soll der Deutsche aktiv werden? Technologieexport: Also, wir sind sicherlich mit führend, wir haben eine fantastische Forschungslandschaft, über die vier außeruniversitären Forschungseinrichtungen (Fraunhofer, Helmholtz, Max-Planck und Leibnitz) ist alles abgedeckt. Da wird gerade jetzt auch finanziell gut nachgelegt, vielen Dank übrigens auch an Sie, dass da noch weitere Mittel fließen, ich glaube, dass dies sehr gute Zukunftsinvestitionen sind. Ich war auch in Katar, habe mit dem Energieminister gesprochen, dort hat man gerade ein neues Erdgasförderfeld – 150 Millionen Tonnen Erdgas-Jahresproduktion – eröffnet. Ja, und wir müssen auch Katar die Möglichkeit bieten, dieses Erdgas so zu verwenden das es klimaneutral ist – Stichwort „türkiser Wasserstoff“ –, dass der CO2-Anteil absepariert wird und als Festkörper sozusagen deponiert wird. Auch das wird auch eine Quelle von Wasserstoff sein, und nicht nur der rein grüne Wasserstoff über Elektrolyse in das globale Energiesystem kommt.

Die Lieferketten für die Syns-Fuels sind eben auch eines der großen Assets. Wir haben tausende von Schiffen, die derzeit Energieträger transportieren. Einem Schiff ist es egal, ob es grünes Methanol oder fossiles Methanol transportiert. Auch diese Assets muss man mitnehmen. Der Übergang ist nicht disruptiv, sondern incremental. Wir müssen aber jetzt die Investitionen global in diesen Übergang – Stichwort Blend-In Fuels – eben auch schaffen, und auch das ist ein wichtiges Argument für die E-Fuels.

Zu den 30 Roadmaps: Der Wasserstoffbedarf ist sehr hoch, und er ist nicht begrenzt. Weil Wasserstoff aus Wasser erzeugt wird und nach der Nutzung auch wieder in Wasser übergeht ist der Kreislauf geschlossen. Das heißt nach der Nutzung in der Brennstoffzelle ist das Ergebnis lediglich feuchte Luft, was aus dem Auspuff kommt, und nicht mehr. Es wird nichts dem System entzogen oder als Ressource verbraucht, sondern das ist ja ein geschlossener Kreislauf. Wie gesagt, die Effizienzkette: sechsmal so viel Energie. Aus unserer Sicht ist das falsch. Wenn man die Gesamtkette sieht, wenn man richtig bilanziert, dann ist das nach unseren Berechnungen eher im Faktor zwei, aber nicht mehr, weil auch die Batterie in der Herstellung bilanziert werden muss, der Strombedarf für die Batterieherstellung und auch der Verbrennungsmotor, der übrigens in dem CO2-Footprint in der Herstellung des Fahrzeugs immer noch am günstigsten abschneidet.

Ansonsten noch zur Zulieferindustrie: Wenn man mal genau guckt, was Scheffler, was ElringKlinger macht: ElringKlinger hat vor zwei Jahren in Brennstoffzellen den Produktionsoutput um Faktor 10 erhöht, weil die Industrienachfrage in China so hoch ist. Die Zulieferindustrie in Deutschland bereitet sich sehr gut auf den globalen Markt, der sich entwickelt, vor. Mirai, das ist das Brennstoffzellenfahrzeug von Toyota, wird schon in der zweiten Fahrzeuggeneration ab diesem Jahr mit einer Stückzahl von 30.000 Einheiten produziert, Hyundai mit dem NEXO in einer ähnlichen Größenordnung. Also, Asien stellt sich wunderbar auf dem Wasserstoffmobilitätssektor auf. Deutschland ist dabei, wirklich Fehler zu machen, wenn es das nicht tut. Die E-Fuels werden auch noch mal im künftigen Mix an Energieträgern in der Mobilität eine wichtige Rolle spielen. Wir haben die technologischen Voraussetzungen, wir haben vor allen Dingen auch die Notwendigkeit, weil wir bislang in der Automobilindustrie in der gesamten Wertschöpfungskette immer vorne mit dabei waren. Bei einem Batteriefahrzeug ist sozusagen von der Wertschöpfungstiefe – offen gesagt – nicht viel dran. Das ist in hohem Maße Softwarethemen, das stimmt, das Stichwort ist gefallen. Autonomes Fahren, Digitalisierung, sind da wichtig, aber da sind wir derzeit weit hinten dran, als Deutschland auch gegenüber dem, was über die USA jetzt schon vorgelegt wurde. Also, wir sollten tunlichst den Fehler vermeiden, jetzt irgendeine Technologie auszuschließen oder auf irgendwann zu verschieben. Toyota ist uns jetzt schon mit den Brennstoffzellen technologiemäßig zehn Jahre voraus, und deswegen ist es gut, dass auch Bosch jetzt eine weitere Milliarde in Brennstoffzellen investiert, um eben diesen Sektor auch künftig bedienen zu können.

Ich sehe, jetzt ist Ihre Uhr von Grün auf Rot umgeschaltet. Ich nehme an, das gilt für uns alle jetzt hier, oder?

Vorsitzender Dr. Andreas Lenz (CDU/CSU): Ja, eigentlich schon. Wenn Sie noch einen Abschlusssatz hätten, dann gerne, aber wir sind wirklich mit der Zeit leider schon vorangeschritten. Es war aber eine sehr, sehr spannende Diskussion, das haben Sie eben auch selbst erlebt. Danke für diesen Input. Ich glaube, uns allen wurde einmal mehr die Dimension der Aufgabe klar, die wir gesellschaftlich vor uns haben. Natürlich wurden auch die Möglichkeiten, die unterschiedlichen Sichtweisen, entsprechend klar. Und letzten Endes muss dann natürlich auch immer die Politik den Rahmen setzen, dass sich dann Innovationen und neue Technologien entsprechend durchsetzen können.

Noch mal ganz herzlichen Dank an unsere Gäste. Wir haben jetzt leider nicht die Zeit für eine zweite Runde. Trotzdem wurde uns sehr viel Input gegeben, auch durch die entsprechenden Unterlagen, und wir würden uns auch vorbehalten, dass wir bei Ihnen dann noch mal nachfragen, sollten sich noch Fragen ergeben. Aber soweit vielen Dank für den Input, für die spannende Diskussion, für den Austausch. Auch an die Gäste, vertreten sind, die Medienvertreter, vielen Dank. Wir stellen jetzt die Nichtöffentlichkeit her und bedanken uns noch mal und wünschen Ihnen einen schönen Abend.

Schluss der Sitzung: 19:08 Uhr

Andreas Lenz

Dr. Andreas Lenz, MdB
Vorsitzender

Deutscher Bundestag
Parlamentarischer Beirat
f. nachhaltige Entwicklung
Ausschussdrucksache
19(26)117

Anlage 1

Alternative Antriebsstoffe: Fokus E-Fuels

Potenziale und Risiken aus der Nachhaltigkeitsperspektive

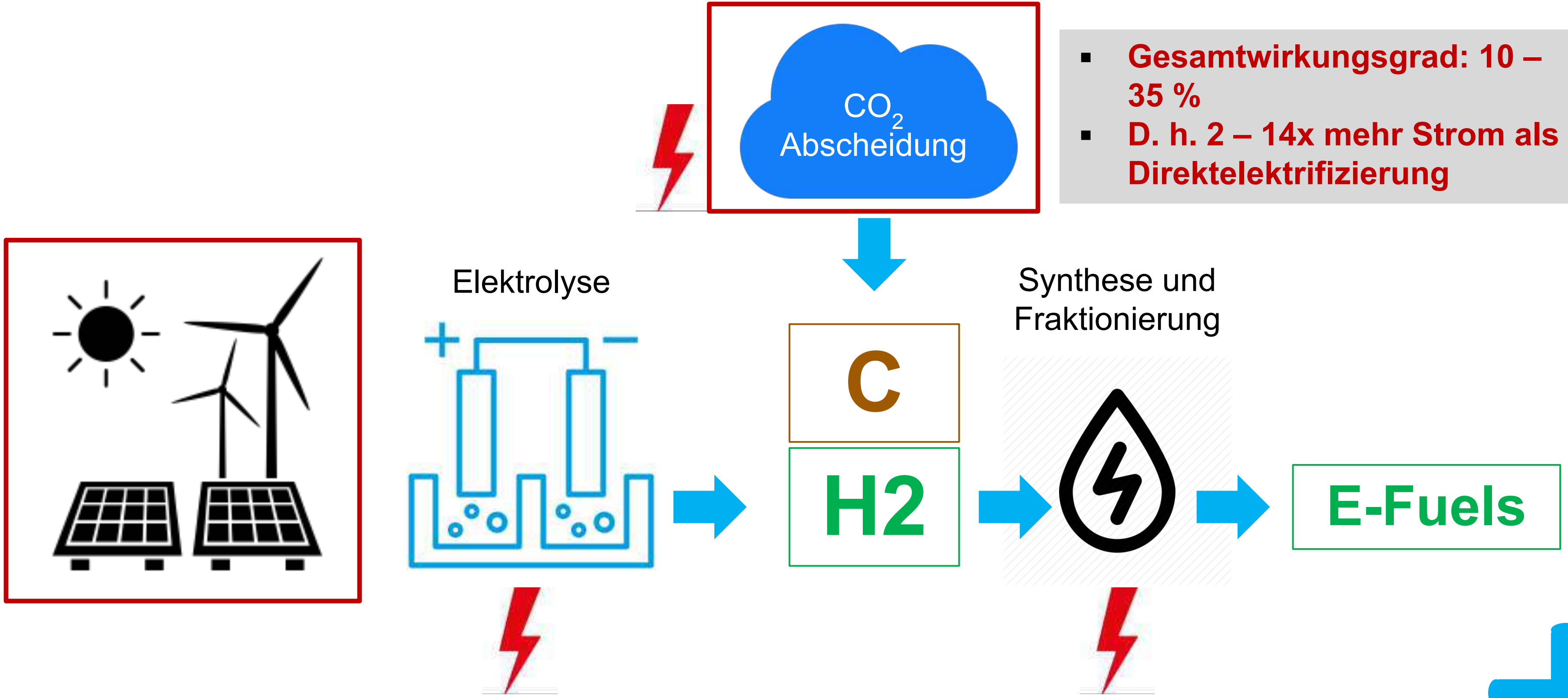
Jekaterina Boening, Senior Policy Manager

TRANSPORT & ENVIRONMENT

I: Wann sind E-Fuels nachhaltig?

Herstellungsprozess E-Fuels

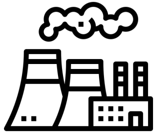
- **Gesamtwirkungsgrad: 10 – 35 %**
- **D. h. 2 – 14x mehr Strom als Direktelektrifizierung**



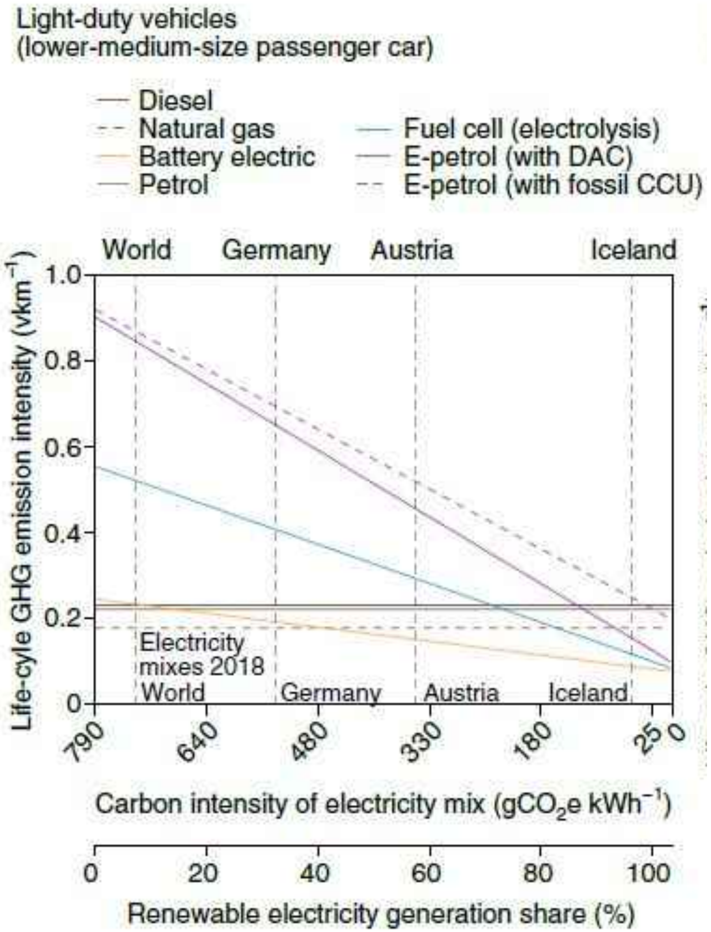
Strombezugsquelle: „Zusätzliche“ erneuerbare Energieanlagen

Wenn die bereits bestehende EE-Erzeugung zugunsten der E-Fuels-Produktion umgelenkt wird, **steigt die CO_2-Intensität des Strommixes:**

↑ N (Stromnachfrage) = EE (fluktuierende Erneuerbare Energien) + ↑ R (Residuallast)



Zusätzlich = neue, nicht staatlich geförderte Anlagen, zusätzlicher Ausbaupfad



- Um eine CO_2-Minderung ggü. fossilen Kraftstoffen mit E-Fuels zu erreichen, bedarf es **eines EE-Anteils von 90 – 100 %**
- Mit heutigem Strommix Deutschlands emittieren die E-Fuels **3 - 4x mehr CO_2 als fossile Kraftstoffe**
- Durch **Elektromobilität** werden bereits mit aktuellem Strommix CO_2-Einsparungen erzielt

Quelle: Ueckerdt, F. et al (2021). *Potential and risks of hydrogen-based e-fuels in climate change mitigation.* In: Nature Climate Change.

CO_2-Quelle: Nur die CO_2-Abscheidung aus der Luft (DAC) ist mit Klimaneutralität kompatibel

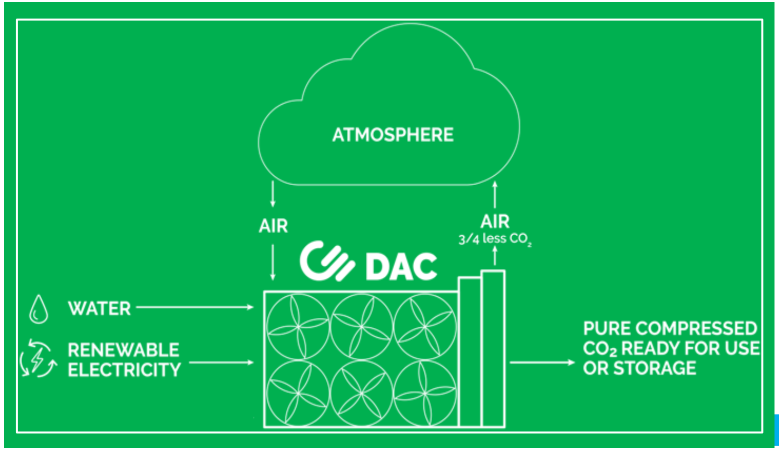
Industrielle Punktquellen:

- Die CO_2-Emissionen werden nicht vermieden, sondern **halbiert**
- Aktuell günstiger als DAC. **Mit steigenden ETS-Preisen** verringert sich der Kostenunterschied.

Direct Air Capture:

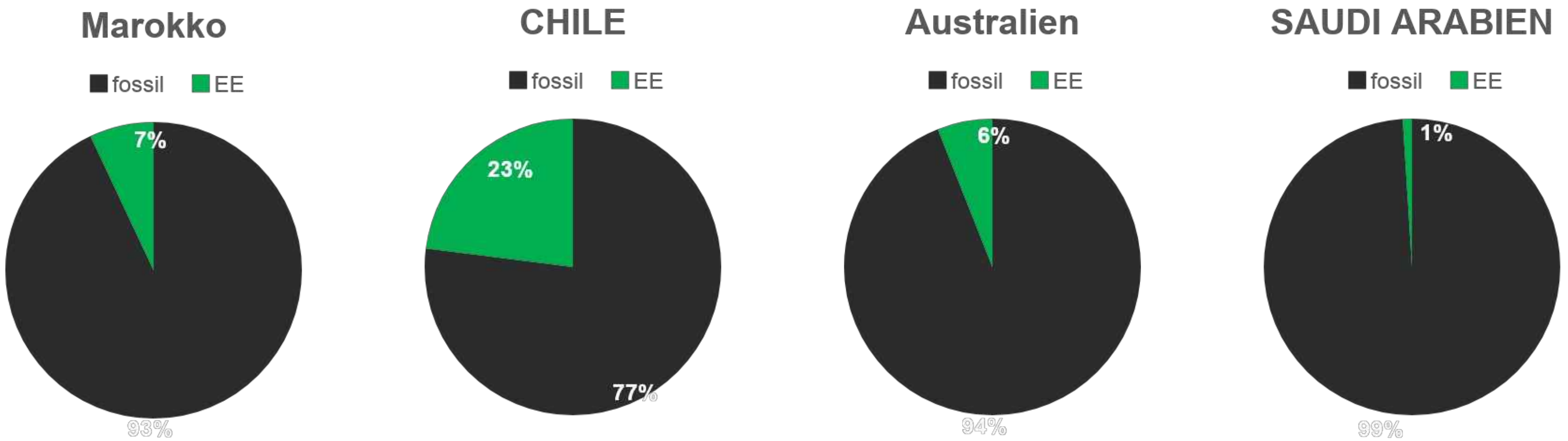
- 15 kleine DAC-Anlagen sind heute weltweit im Betrieb. Die erste Anlage im Industriemaßstab entsteht in den USA.
- DAC muss von Beginn an in der Produktion von E-Fuels **regulatorisch verankert werden**, um die industriellen Punktquellen schrittweise komplett zu ersetzen.

Carbon2Chem®



II: Wie können die SDG-Ziele eingehalten werden, wenn die Vision von PtX-Importen künftig realisiert wird?

Der Energiemix von potenziellen Exporteuren ist heute überwiegend fossil



E-Fuels-/Wasserstoffproduktion für Exporte darf nicht auf Kosten der Dekarbonisierung der einheimischen Energieversorgung stattfinden (SDG 7). Für das Klima wäre dies (im besten Fall) ein Zero-Sum-Game.

Quelle: Our World in Data; Australian Energy Update 2019

Welche zusätzlichen Nachhaltigkeitsaspekte sind mit Blick auf PtX-Importe zu beachten?

- Definition der **„Zusätzlichkeit"** in Ländern mit **überwiegend fossilem Energiemix** (z. B. bestimmter Anteil von EE-Anlagen muss der einheimischen Energieversorgung zur Verfügung stehen) (SDG 7, 13).

- Berücksichtigung des **Wasserbedarfs der Elektrolyse in Wüstenregionen** (SDG 6). Entsalzungsanlagen müssen mit EE-Strom betrieben werden.

- **CO_2-neutraler Transport** (CO_2-neutrale Antriebsstoffe für Schiffe, H2-Pipelines).

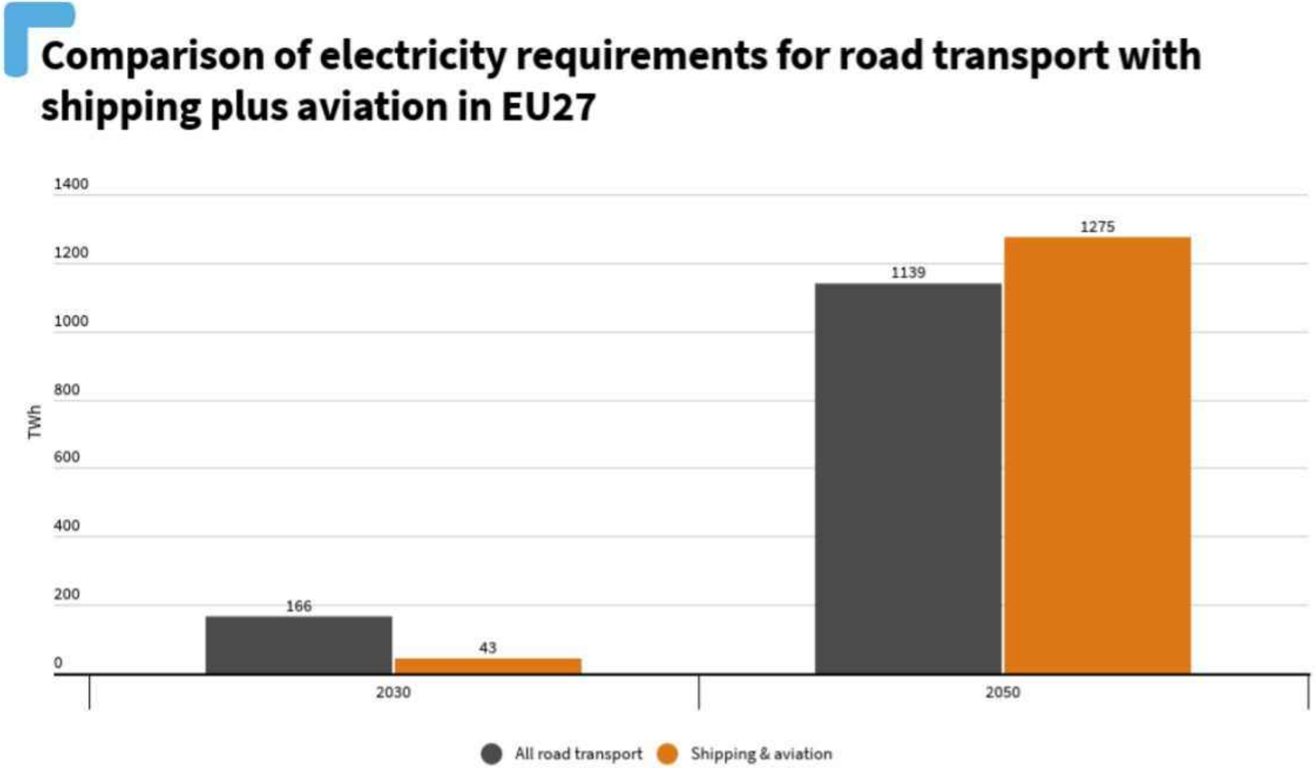
- Es bedarf **eines internationalen Zertifizierungssystems** für PtX-Produkte.

- **Heute gibt es keine internationalen PtX-Lieferketten**. Die Klimaschutz- und die Industriestrategie auf der Vision von Importen zu bauen birgt große Risiken.

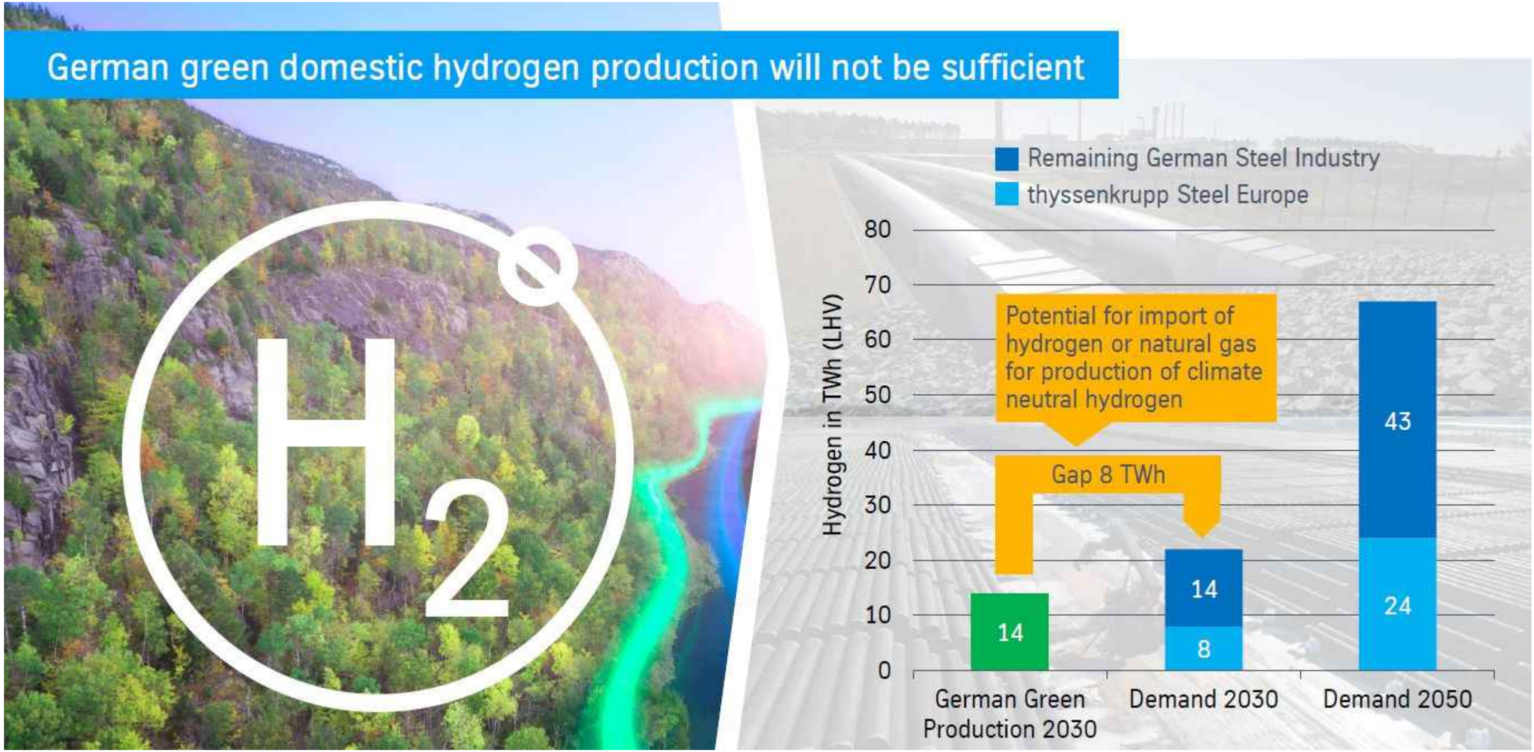
III: Wo werden E-Fuels künftig eingesetzt?

Alternative Antriebstoffe sind zentral für die Dekarbonisierung der Luft- und Schifffahrt

Zur Produktion von PtX für die europäische Luft- und Schifffahrt sind 1275 TWh EE-Strom erforderlich



Die Verfügbarkeit von grünem Wasserstoff ist entscheidend für die Zukunftsfähigkeit der europäischen Industrie



Im Straßenverkehr haben die E-Fuels keine Zukunft


GASTKOMMENTAR GRÜNDLER UND KAMMEL

Warum die Zukunft dem Elektro-Lkw gehört

Wasserstoff ist nicht die beste Lösung für einen nachhaltigen Straßengütertransport. Der reine E-Antrieb ist meist kostengünstiger und effizienter, meinen Matthias Gründler und Andreas Kammel.

12.04.2021 - 21:06 Uhr • 10 x geteilt

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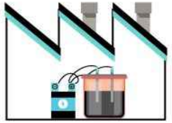
Sorgenkind Bestandsflotte

- Flottenerneuerung mithilfe von ambitionierten europäischen Flottengrenzwerten sowie der Anpassung der Dienstwagenbesteuerung
- Maßnahmen zum Voranbringen einer echten Mobilitätswende (u. a. Ausbau ÖPNV, Stärkung des Schienennetzes, Abbau Dienstwagenprivileg, leistungsabhängige Maut)
- E-Fuels (sowie auch Biokraftstoffe) bieten nur eine Scheinlösung wie u. a. die Berechnung zu 5% E-Fuels im Straßenverkehr zeigt

Was bedeuten 5 % E-Fuels im Straßenverkehr?

15 GW Elektrolyse-Kapazität

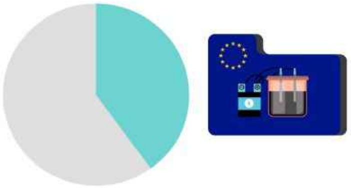


60 TWh zusätzliche erneuerbare Stromerzeugung

20 GW zusätzlicher Ausbau Wind-Onshore

3x Mal das Elektrolyse-Ziel der Wasserstoffstrategie

40 Prozent des europäischen Elektrolyse-Ziels



Quelle: Eigene Analyse von T&E

Fazit

- Der Herstellungsprozess von E-Fuels ist komplex. **65 – 90 % der eingesetzten Energie geht verloren**. Die wichtigsten Faktoren für die Nachhaltigkeit von E-Fuels sind die **Strombezugs- sowie die CO_2-Quelle**.

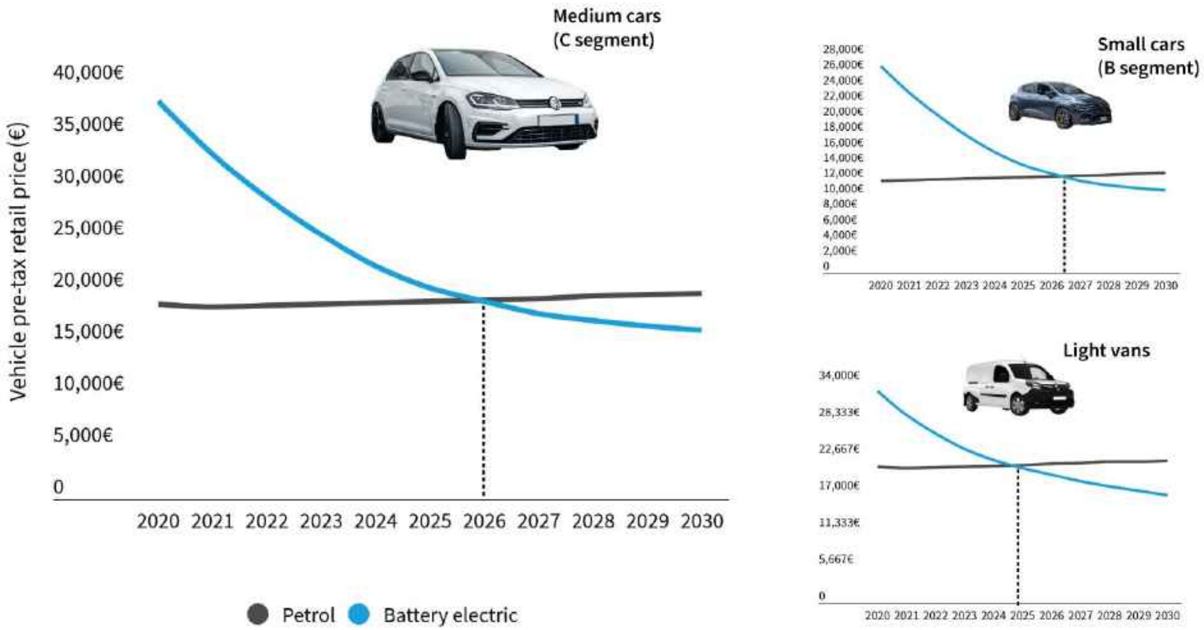
- Nur durch den Einsatz von „zusätzlichen“ erneuerbaren Energien sowie der CO_2 aus der Luft können die E-Fuels CO_2-Einsparungen ggü. fossilen Kraftstoffen erzielen. Mit heutigem Strommix Deutschlands emittieren die E-Fuels **3 - 4x mehr CO_2 als fossile Kraftstoffe.**

- Für PtX-Importe bedarf es eines **internationalen Zertifizierungssystems**. Dieses muss u. a. das Kriterium der „Zusätzlichkeit“ in Ländern mit überwiegend fossilem Energiemix definieren sowie den Wasserbedarf und den CO_2-Abdruck aus dem Transport berücksichtigen.

- Trotz der hohen Kosten und komplexen Nachhaltigkeitsanforderungen sind die **Luft- und Schifffahrt sowie der Industriesektor auf PtX angewiesen**. Im Straßenverkehr haben die E-Fuels keine Zukunft, was in der aktuellen **Marktentwicklung** deutlich zu sehen ist.

Vielen Dank!

E-Fahrzeuge werden die Kostenparität mit fossilen Verbrennern 2025 – 2027 erreichen



Note: all other vehicles segments, large cars, small, medium and large SUVs as well as heavy vans all hit price parity in the same year as the medium car – in 2026

Source: Bloomberg NEF (2021), Hitting the EV Inflection Point

Deutscher Bundestag
Parlamentarischer Beirat
f. nachhaltige Entwicklung
Ausschussdrucksache
19(26)117-1

E-fools: why e-fuels in cars make no economic or environmental sense

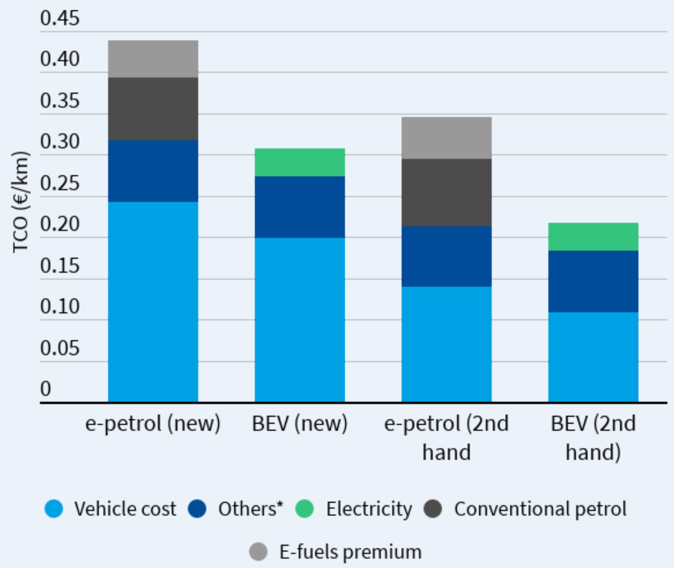
April 2021

Summary

With the review of the EU CO_2 emissions standards for cars and vans scheduled for June 2021, some, notably the oil and gas industry and automotive suppliers, are advocating adding CO_2 credits for advanced biofuels and synthetic fuels into the vehicle standards. T&E's new analysis shows why this is not credible— neither from an environmental nor from an economic point of view.

Out of the Green Deal compatible technologies to decarbonise cars - sustainable batteries, green hydrogen and renewable e-fuels - electrifying cars directly using batteries is by far the most efficient zero emissions pathway to decarbonise cars. Driving a car on e-fuels produced from renewable electricity would require close to five times more energy than when driving a battery electric vehicle (BEV). Additional analysis in this paper now shows how both on cost and lifecycle emissions BEVs strongly outperform e-fuel powered petrol cars.

Economic perspective: e-fuels would place a cost burden on both the economy and drivers



T&E's **Total Cost of Ownership** (TCO) **analysis** shows that the very high costs of operating a conventional **vehicle running on e-fuels would place a cost burden on the average European driver**. For both new and second hand cars in 2030, the TCO premium for running a car on e-petrol compared to a BEV is €10,000, or 43% more expensive for an average driver. Critically, the TCO of running an existing petrol car on e-fuels would still be 10% higher than buying a new battery electric car, making e-fuels an unaffordable and unsuitable option for the existing fleet.

E-fuels would also be **the most costly CO_2 compliance route for carmakers**. It would cost carmakers around €10,000 in fuel credits for the amount of synthetic petrol needed to compensate for the emissions of an efficient petrol car placed on the market in 2030. On the other hand, the cost of a BEV battery could plunge down to €3,000 by 2030— or more than three times less than what carmakers would pay for fuel credits— and with BEVs reaching cost parity with ICE in the mid 2020s, producing a battery electric vehicle rather than a petrol car will not require much additional investment. The e-fuel route would therefore put the competitiveness of the European automotive industry at risk as it would divert large investments away from the transition to emobility.

The higher compliance costs from e-fuels will eventually be passed on to the wider society leading to a less cost effective trajectory for our society and our economy as a whole. T&E shows that the total **additional cost of an e-fuel pathway would be five times higher compared to the electrification pathway**. The industry claims that producing e-fuels in Africa and importing them to the EU would lower the costs thanks to cheaper solar PV. In this paper, T&E assumes this most favourable case for e-fuels where these fuels would be available in 2030 and shows that the lost revenue for the EU economy could be around 10 times higher for the e-fuels pathway compared to domestically produced batteries from the early 2020s).

In brief, the idea of powering cars with e-fuels does not have economic credibility— neither from the drivers perspective, nor from the carmakers compliance angle or from the economy as a whole. **Allowing e-fuels credits would thus only increase the costs of decarbonisation and delay the inevitable transformation towards affordable electric mobility**.

Climate perspective: e-fuel environmental benefits are a mirage

Updated T&E lifecycle CO_2 analysis shows that **the average amount of CO_2 emitted by new BEVs powered by the EU electricity grid in 2030 is around 40% lower than for a petrol car running on the e-fuels** which meet the RED II sustainability criteria.

If electricity with the same carbon intensity is used to power the BEV and to produce the e-fuel (in line with RED II criteria), the battery car emits half as much as the comparable petrol car running on e-fuel. Conventional cars powered with e-fuels consistently emit more CO_2 than an equivalent BEV, including in Germany where such e-fuels are high on the agenda. **Using e-fuels to power conventional cars will provide considerably less climate benefits,** on top of requiring much more renewables.

Availability: e-fuels should not be diverted to cars where better alternatives exist

The limited availability of scalable sustainable fuels means that there is no scope to use renewable electricity inefficiently for the production of e-fuels for road transport where other more efficient, cleaner and cheaper solutions are available. Promoting even a limited use of synthetic hydrocarbons in road transport now will divert the manufacturing and supply chains from being targeted at sectors such as aviation, maritime or the heavy industry. This makes the transition harder to accomplish and could seriously delay the decarbonisation of the economy sectors which cannot use batteries to decarbonise.

Vehicles CO_2 regulations should not allow fuel credits

Adding e-fuels to the car CO_2 regulation would greatly weaken its effectiveness. Carmakers would be able to buy fuel credits instead of accelerating what they have direct control over: the efficiency and the electrification of their vehicle sales. The effectiveness would also be watered down when mixing different sectors (downstream transport vs. upstream fuels), already covered in effective sector-specific legislation. From the smart regulation point of view, such a complex compensation system would likely **undermine the credibility and enforceability of the regulation**.

The EU is at risk of making an untenable tactical blunder. Rewarding synthetic fuels under the cars CO_2 standard regulation is a bad idea- implementing this would delay electrification in road transport, prolong life of polluting engines and postpone the economy-wide decarbonisation by misallocating green electrons. With no e-fuels at scale in sight, and a surge in electric car sales, the e-fuels appear to be a Trojan Horse to keep combustion engines and demand for hydrocarbons alive. Politicians must not allow the transition to zero emissions mobility to slow down.

⇒ **There should be no CO_2 credits given to auto makers for either alternative or synthetic fuels used in road vehicles under the vehicle CO_2 regulations.**

Introduction

To achieve a European Green Deal objective of reaching climate-neutrality by 2050, the European Commission will propose the 'Fit for 55' legislative package to reduce emissions by at least 55% by 2030. As part of this package it will propose a revision of the cars and vans CO_2 emission standards in June 2021 in order to align cars and vans with the wider decarbonisation strategy.

Amidst the discussions on the upcoming revision of car CO_2 regulation, the idea to add credits for advanced and synthetic fuels into the EU vehicle CO_2 standards has resurfaced, heavily pushed by the oil and gas industry. Already in 2017 and 2018, during the last round of EU light duty and heavy duty CO_2 negotiations, the same industry had been unsuccessfully advocating to include such a mechanism in the regulation.

In May 2020, a study commissioned by the German economic ministry advocated for synthetic and advanced alternative fuels to be included into the regulation[1]. In November 2020, T&E highlighted the shortcomings of the study, showing that this approach was a bad idea and had no regulatory credibility[2].

In this paper, T&E goes further and provides a deeper economic and climate assessment of the implications of having conventional cars run on synthetic fuels, focusing on conventional cars running on e-petrol.

1. High costs for drivers

1.1 Quadrupling energy costs

Synthetic fuels -or e-fuels- are produced by combining hydrogen and carbon in order to create a hydrocarbon (like petrol or diesel) which can be used to propel a conventional petrol or diesel vehicle[3]. The hydrogen can be produced via electrolysis by splitting water into hydrogen and oxygen molecules while the carbon can be obtained via direct carbon capture.

Because of this energy intensive process, running a car on synthetic petrol is close to five times less efficient than powering a BEV through direct electrification[4]. The overall efficiency of the direct electrification pathway is 77% whereas it is 16% for petrol cars powered with synthetic fuels.

With more complex and energy intensive processes, also comes higher fuel costs and transportation costs. In 2030, **the energy cost to power an efficient petrol car running on synthetic fuels will be close to four times higher than for a BEV** (Figure 1). Depending on the extent to which the production cost of

[1] Frontier Economics (2020), *Crediting system for renewable fuels in EU emission standards for road transport.* Link
[2] Transport & Environment (2020), *Why adding fuel credits to vehicle standards is a bad idea.* Link
[3] Only synthetic fuels produced from electricity will be considered in this paper.
[4] Transport & Environment (2020), *Electrofuels? Yes, we can … if we're efficient.* Link

e-fuels drops in the next decade, the energy cost would be in a range of 3.4 and 4.2 times higher (3.8 based on our central scenario) with synthetic fuels.

The industry claims that producing e-fuels in Africa and importing them to the EU would lower the costs thanks to cheaper solar PV[5]. In this paper, T&E assumes this most favourable case for e-fuels where these fuels would be available in 2030. However, T&E does not think it is realistic in the medium term because no certification, standards, infrastructure, or long-term contracts are in place yet. Furthermore, the additional costs from the handling and the distribution of the fuel from production to the consumer point could add costs which are not totally reflected here. Even in this most optimistic scenario, e-fuels remain much more expensive for the driver. T&E does not support or endorse this option but uses it here as a most optimistic case to debunk the fact the e-fuels can be cheaper thanks to imports. The assumptions are detailed in the info box below and in the Annex.

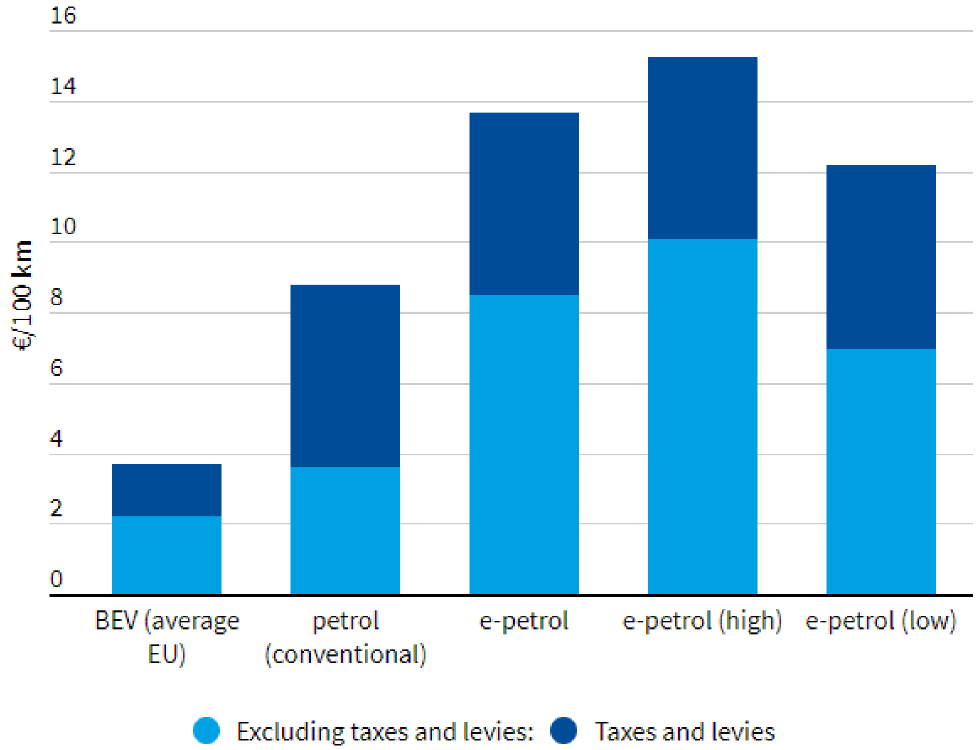


Figure 1: Energy cost comparison of electricity and liquid fuels for an average car(EU average)

For synthetic diesel fuel similar results are found (not shown here) with a range of energy costs being between 3.3 and 4.3 times higher (3.8 under the central assumption).

[5] See for example the eFuel Alliance : https://www.efuel-alliance.eu/de/efuels

Synthetic fuel cost assumptions

The Agora PtG/PtL calculator was used to calculate the levelised cost of electricity (LCOE) and the cost of synthetic e-petrol and e-diesel excluding taxes & levies based on the reference scenario.[6] The electricity generation and fuel production facilities are based on solar PV in North Africa (most optimistic assumption, not supported by T&E). The chosen weighted average cost of capital (WACC) is 6% and the method of CO_2-extraction is direct air-capture (DAC). Solar PV in North Africa was set at a load factor of 2,344 full-load hours per year. High-temperature electrolysis as well as FT-synthesis were set at 4,000 full-load hours and, thus, rely on temporary hydrogen storage.

The transport and distribution costs are based on Fasihi et al. and take into account transport via tanker vessels from North Africa (Algiers) to the Port of Hamburg and domestic distribution to the refuelling station via conventional tanker trucks.[7]

Overall production costs in 2030 are 1.3 €/L for e-petrol, which translates into a price of 2.3 €/L for the consumer once taxes, levies and transport are included (same final price for e-diesel). Taxes and levies are assumed to be the same as for fossil petrol in the EU27: 0.86€/L (2020 average).

1.2 High total costs of ownership (TCO)

Already today, the total cost of ownership (TCO) of a BEV is lower than the TCO of a comparable conventional car in more than ten European countries[8] and their economic case will only be strengthened in the next few years. Indeed, BEV prices will drop and are expected to reach upfront parity with ICEs in the mid 2020s (without subsidies)[9] thanks to decreasing battery costs (-60% between 2020 and 2030[10]) and improvements of manufacturing techniques, notably through integration and scale[11]. On the other hand, even in the optimistic scenario, e-fuel price will remain higher than today's conventional fuel price (as shown above).

New BEVs are one third cheaper than new petrol with e-fuel

As a result, the TCO of a BEV purchased in 2030 would be 30% lower than for new efficient petrol cars running on synthetic fuels. Both the vehicle cost and the fuel cost are expected to be lower for the

[6] Agora Verkehrswende et al. (2018). PtG/PtL calculator. Retrieved from https://www.agora-energiewende.de/en/publications/ptg-ptl-calculator/

[7] Fashihi et al. (2016). Techno-Economic Assessment of Power-to-Liquids (PtL) Fuels Production and Global Trading Based on Hybrid PV-Wind Power Plants. Retrieved from https://www.sciencedirect.com/science/article/pii/S1876610216310761, various pages.

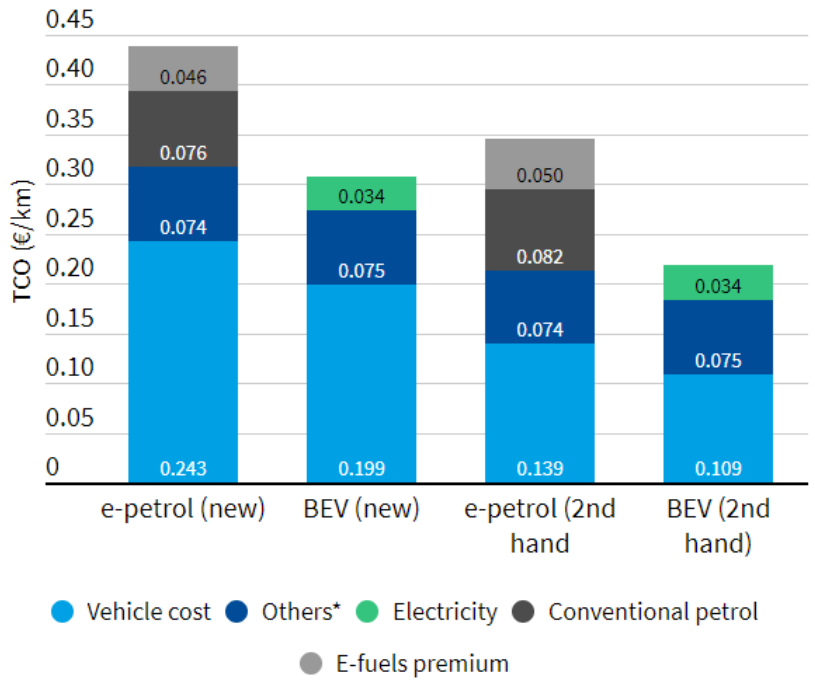
[8] Leaseplan calculates a lower TCO for BEVs in 11 countries out of 22 European countries. The 11 countries are: Austria, Belgium, Denmark, France, Germany, Italy, Luxembourg, Netherlands, Norway, Portugal and the UK. Source: LeasePlan (2021), EV Readiness Index 2021. Link

[9] BNEF (2020), Electric Vehicle Outlook 2020. Link

[10] BNEF, March 5 2019, *A Behind the Scenes Take on Lithium-ion Battery Prices.* Link

[11] McKinsey (2019), *Making electric vehicles profitable* Link

BEV in 2030, which puts the e-petrol option in a position which would be untenable for the average driver. All assumptions are detailed in the Annex.



* Others include insurance, maintenance and cost of a private charger
TCO comparison for a medium car, based on European averages and 5 year ownership period. E-fuel cost: T&E calculations based on Agora Verkehrswende et al. (2018) and Fasihi et al. (2016).

Figure 2: TCO comparison BEV vs. ICE in 2030

After a 5 year ownership period, a driver buying a new petrol car and driving on e-petrol would spend an additional €10,000 than with a new BEV.

It is assumed here that the petrol car drives on 100% e-fuels, which would be the most expensive option for the driver. In reality, it is likely that e-fuels would be blended with overall fuel mix (including conventional fuel). However, the results presented above hold true even in the situation where e-fuels are blended. For example with a 50% e-fuel blend the 'e-fuel premium' in grey in Figure 2 would be cut by half and the BEV would be 26% cheaper instead of 30% cheaper.

New BEVs are still cheaper than 2nd hand petrol cars with e-fuel

The industry often puts forward the idea that synthetic fuels are an effective solution to decarbonise the existing car fleet stock. While it might be true that a car running on e-fuels produced from renewable energy, would emit less CO_2 than if it was running on fossil fuels (but still more than a BEV, see Section 3), a second hand petrol car running on e-fuels would still be very expensive when compared to 2nd hand BEV. Similarly to new cars, the premium for running a second hand car on e-petrol compared to a second hand BEV is also around €10,000. The ownership period (5 years) and distance driven (15,000 km per year) assumed here is the same for the first and second ownership period for a like-for-like comparison. In reality, older vehicles are driven less than new vehicles. This would reduce the fuel and electricity costs for both second hand vehicles in the figure.

Running a second hand petrol car is still 10% more expensive than buying a new BEV. This means that even buying a new BEV is still a cheaper solution for drivers than using an existing petrol car powered by e-fuels. This result is calculated with a first hand and a second hand car running the same distances over their ownership periods, which means the driver would have the same driving habit with a new or second hand car. Different mileages between the first and second hand owner can lead to different results.

In conclusion, new T&E TCO analysis shows that the very high costs of operating a conventional vehicle running on e-fuels would place a great burden on the average European driver effectively making this economic option implausible. Mobility costs for consumers would simply be too high.

2. Effects on our economy

2.1 E-fuels are the most costly compliance route for carmakers

Accounting for fuel credits under the car CO_2 emission standards would effectively allow carmakers to buy their way into compliance. Indeed, rather than improving the vehicle tailpipe emissions and shifting to zero emission mobility, OEMs could buy credits from fuel suppliers for synthetic fuel that are placed on the market. In this section, T&E shows that carmakers' 2030 compliance costs for placing an e-fuel powered conventional vehicle on the road are several times higher than those for BEVs.

Methodology: The cost of a synthetic fuel credit is calculated as the production cost premium of going from conventional petrol fuel (excluding taxes and levies) to renewable-based synthetic petrol. In order to compensate the emissions of a petrol car placed on the market and consider it as zero emission on paper, zero emission synthetic fuel credits equivalent to what the vehicle will consume over its whole lifetime are considered. This is compared to the cost of a battery in a BEV.

T&E shows that in 2030 it would **cost close to €10,000 in synthetic fuel credits to compensate for the emissions of an efficient petrol car placed on the market** (around €11,000 in 2025). On the other hand, we can compare this with the cost of a BEV battery, which would cost around €4,400 in the early 2020s and €3,000 in 2030, or between **two and three times less** than the price of the fuel credits calculated above.

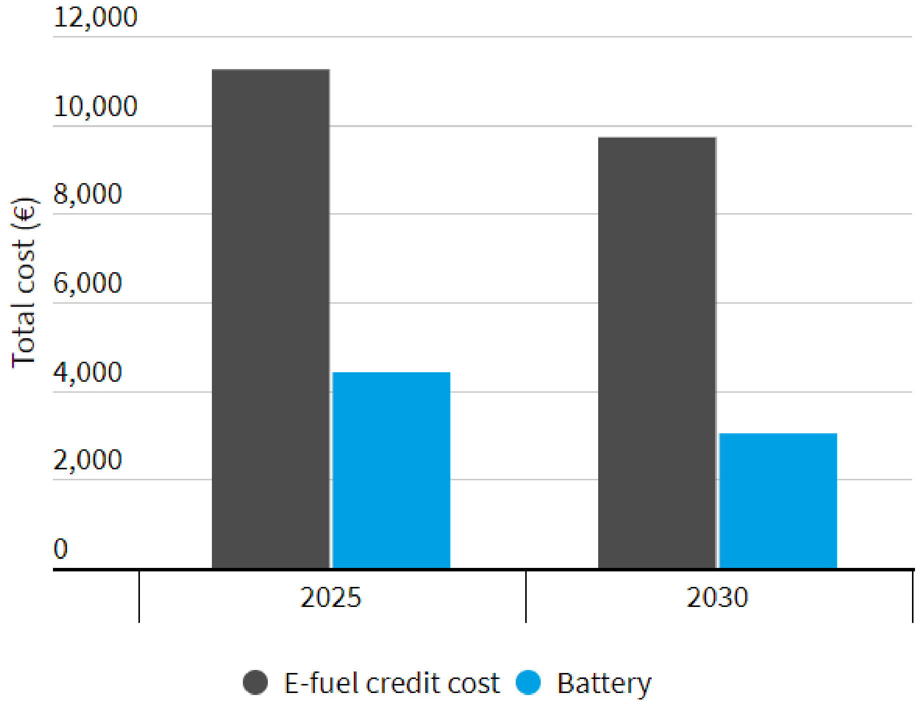


Figure 3: Comparison of e-fuel compliance route with battery price

In reality, the comparison between the cost of the efuel credits and the battery price is disingenuous, as **selling or producing a BEV will not require OEMs to pay any money upfront**. BEVs will reach production cost parity with ICEs in the mid 2020s. This implies that, all else being equal, in reality, the drivetrain of a BEV (battery, motor(s), and electronics) would not cost more than that of an ICE (engine, exhaust treatment, transmission). In 2030 the list price of BEVs is likely to be lower than for ICEs thanks to lower battery costs, optimised BEV platforms and economies of scale, which indicates that the compliance cost for an OEM for going for a BEV rather than a petrol could even be negative. Therefore, at this stage, it will not cost carmakers more to produce and sell a BEV rather than an ICE.

In short, as already shown by T&E in autumn of 2020[12], synthetic fuels are the least cost-effective path for carmakers. Complying using e-diesel and e-petrol credits raises compliance costs two-to-three-fold and these higher expenses made by carmakers would divert investments away from the emobility transition (e.g. in new BEV dedicated platforms or battery production) into the pockets of the oil and gas industries.

2.2 Social costs

The higher compliance costs for an efuels pathway will eventually be passed on to the wider society leading to a less cost effective decarbonisation trajectory for our society and our economy as a whole. In this section T&E shows that the total additional societal **cost of an e-fuel pathway would be five times higher compared to a BEV pathway**.

[12] Transport & Environment (2020), *Why adding fuel credits to vehicle standards is a bad idea.* Link

Both pathways are based on an increase in the ambition of the 2030 car CO_2 emission standards from the current 37.5% to a hypothetical 50% reduction. In the BEV scenario, the additional efforts are achieved by selling an extra 3 million BEVs in 2030 (on top of close to 4m BEV and 2m PHEV needed for the current 2030 target). In the hypothetical e-fuels pathway scenario, the compliance gap is bridged by only buying fuel credits to compensate the lifetime emissions from the fuel burnt by the same amount of petrol cars. When stacking up the vehicle sales in the 2020s, there is an additional 13 million BEVs in the vehicle stock in the BEV scenario. This comes on top of the 22 million BEVs and 15 million PHEVs on the road in 2030 needed to comply under the current targets. In the e-fuels pathway an additional 13 million petrol cars running on e-fuels in the e-fuel pathway are placed on the roads in the 2020s.

In the e-fuels scenario, the total production cost of the e-fuels needed for those 13 million petrol cars to be accounted as zero emission vehicles would be €230 billion up to 2030. On the other hand the additional battery costs to produce these 13 million BEVs is under €50 billion, or around five times less. The battery costs considered here are based on BNEF's forecast: 74 €/kWh in 2025 and 51 €/kWh in 2030[13], see Annex for more details.

Methodology

To understand to what extent the money spent on batteries or efuels would be spent overseas versus invested back into the European economy, T&E has made estimates of the share of the total spendings which are kept in the EU versus leaving the EU for the vehicles which are placed on the market up to 2030. As explained in Section 1.1, the most optimistic case for e-fuel costs are assumed in this paper (as advocated by the industry) where e-fuels would be produced and imported from Africa. The timeframe of the analysis looks at the 2020s, and includes the full lifetime costs of the e-petrol credits needed to fuel the petrol car. Although T&E deems it is unrealistic that e-fuels would be produced and imported from Africa in the 2020s, it was nonetheless assumed that small volumes of these e-fuels would be imported before the 2030s in order to carry out the full societal cost impact of this scenario. The e-fuel imports before 2030 actually only account for a limited share of the overall e-fuel imports needed to power the cars placed on the market in the 2020s over their lifetime. Indeed, the e-fuel consumed by the petrol cars before 2030 would account for around a quarter of the total e-fuel consumed over their lifetime, with less than 10% before 2027, and less than 2% before 2025.

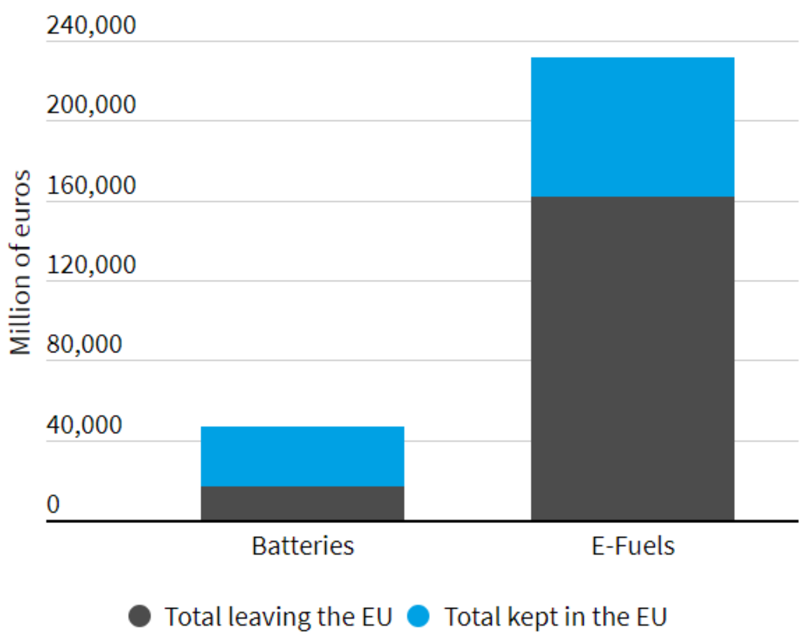
Out of the total production cost of synthetic fuels, T&E assumes that only 30% would flow back in Europe (see Annex), thanks to the added value generated by the European fuels and hydrogen industry when selling the technology necessary for the overseas production. On the other hand, T&E assumes that around a third of the overall battery price does not create economic value in the EU (i.e. flows outside Europe). Indeed battery raw materials account for around a third of the overall battery price and with recycling and EU gigafactories, the industry will create economic value (hence jobs) in the EU. Conservatively, the economic benefits of primary supply of raw materials from European sources and recycling are not accounted for here (this would lead to lower reliance on primary raw materials from outside the EU).

Results

[13] Adjusted to higher battery prices in Europe compared to the global average up to 2030

Based on the above, T&E estimates that the economic value flowing outside of the EU in the BEV pathways is €16 billion while it would be close to €160 billion in the e-fuels pathway.

In brief, the total societal spendings in the BEV pathway scenario are around five times lower than in the e-fuels scenario but given a larger share of these costs would be spent on e-fuels imports, **the economic cost of lost revenue for the EU would be close to 10 times higher in the e-fuels pathway.**



Comparison of the costs incured from meeting an increase in the car CO2 ambition to 50% emission reduction in two different pathways: e-fuel for cars or BEVs

Figure 4: Societal costs: BEV vs. efuel pathways compared

Choosing to power cars with e-fuels means that European drivers and the EU economy as a whole would have to pay the big price and **send billions of euros abroad**, just like we do today for oil.

The conclusion is clear: the idea of powering cars with e-fuels doesn't have any economic credibility, neither from the driver perspective, nor from the OEMs compliance angle or from the economy as a whole. Allowing e-fuels credits would thus only increase the costs of the ongoing transformation towards electric mobility.

3. E-fuel powered cars emit much more CO_2 than battery electric cars

Synthetic fuels - which require a large amount of electricity to be produced - are only as clean as the electricity used to produce them. In this section T&E analysis shows that even under the new sustainability criteria laid out in the Renewable Energy Directive (RED) - which requires efuels to be produced from renewables to a very large extent- the climate impact of a petrol car running on e-fuels is much worse than for a BEV.

General LCA methodology

Throughout this section, the comparison is on lifecycle emissions of a new vehicle in 2030. The lifecycle analysis for the petrol cars powered by e-fuels is broken down in two steps: first the eligible e-fuels are determined with the RED II sustainability criteria (more details below), which is undertaken on a WTW basis. In other words, the RED II criteria are used to determine how much renewable electricity (counted as zero based on a WTW approach) is necessary to produce the efuel. Second, the lifecycle CO_2 emissions from the fuel production which meets the WTW sustainability criteria are calculated and plugged into T&E's EV LCA tool. The total amount of electricity consumed by the vehicles is calculated over this lifetime and lifecycle emissions of each electricity source is then accounted for based on respective lifecycle emissions factors from the IPCC. This lifecycle emission analysis thus provides a broader picture, including indirect emissions from the infrastructure for renewables (i.e. renewables are not zero emission) as well as other emissions from the production of the vehicle and the EV battery for example. For more details on EV LCA methodology, please see previous T&E report[14].

Methodology: GHG reduction from e-fuels under the RED II

The RED outlines a regulatory framework to ensure the sustainability of so-called renewable fuels of non-biological origin (RFNBOs) by requiring at least 70% greenhouse gas savings compared to their fossil fuel equivalent[15]. In effect, this implies that a high share of renewable electricity will be needed to meet this threshold. Around 90% of the electricity will have to come from renewables if a combination of electricity from renewables and gas is used. In the situation that grid electricity is used in 2030 to produce the e-fuel, the share of additional renewable electricity would still have to be around 70% (on top of the 55% renewables included in the 2030 electricity mix[16]). For a combination with gas generation with CCS the share of additional renewables would be similar - 67%. In this analysis T&E assumes that the 70% GHG reduction criteria for e-fuels is calculated based on WTW emissions emissions from energy sources (i.e. not lifecycle emissions, which means that renewables are counted as zero - no infrastructure related emissions). In this methodology we assume direct air capture of CO_2 and we do not consider the different point source possible (only the energy used to perform carbon capture and utilisation is accounted for).

In January 2021, T&E laid out detailed recommendations on what the minimum criteria for RFNBOs should be under the still-to-be-defined RED II methodology in order to ensure the sustainability of electrofuels[17]. Crucially it is key that the renewable electricity used needs to be produced from *additional* renewable sources: This would favour Power Purchase agreements in new and unsubsidised renewables

[14] Transport & Environment (2020), *How clean are electric cars?* Link

[15] The European Commission has been tasked to adopt a delegated act by the end of 2021, on how to calculate the greenhouse gas savings of RFNBOs. Here, T&E conservatively assumes that the 70% reduction set by the European Commission is on the lifecycle emissions of the fuels produced.

[16] Source: ENSOE Ten Year Network Development Plan from 2020. For more see: Transport & Environment (2020), *How clean are electric cars?* Link

[17] Transport & Environment (2021), *Getting it right from the start: How to ensure the sustainability of electrofuels.* Link

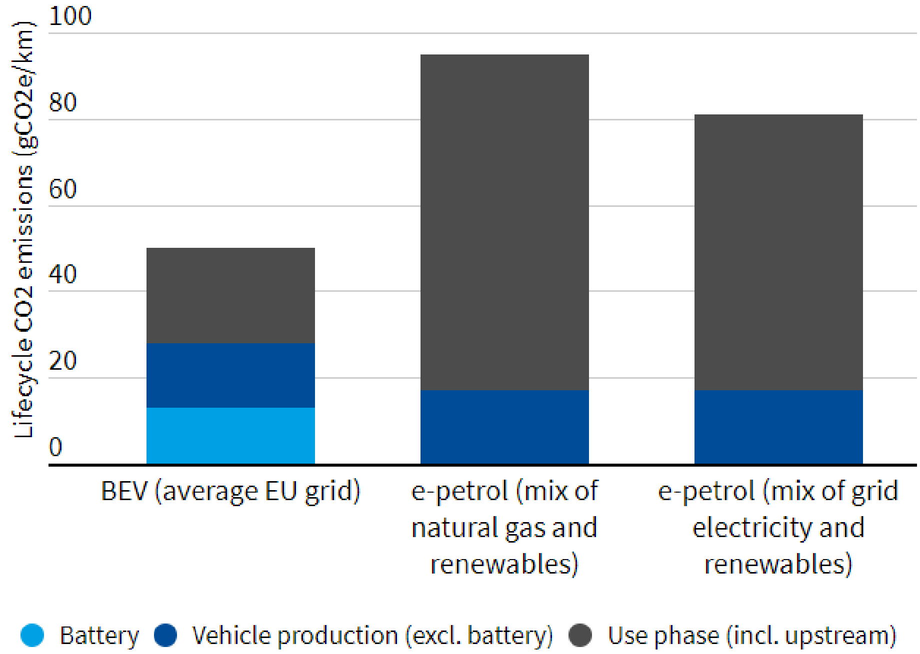
projects rather than allowing for Guarantees of Origin which are not fit for purpose (no additionality, no temporal correlation, risk of double counting etc). Furthermore, the methodology should encourage non-fossil circular sources of carbon like direct air capture. Failing to promote atmospheric sources of carbon entails risks of lock-in of cheaper fossil sources of CO_2 from industrial sources.

Results: BEVs emit 38%-46% less CO_2 over their lifecycle

T&E has updated its lifecycle CO_2 analysis from the 2020 report 'How clean are electric cars?'[18] and associated tool (*transenv.eu/LCA*), to compare the lifecycle emissions of new BEVs with new petrol cars running on e-fuels in 2030.

Although the electric car has a 'carbon debt' when coming out of the factory gate due to the production of the battery, **the average total lifetime amount of CO_2 emitted by new BEVs running on average EU electricity in 2030 is around 40% lower than compared to a petrol car running on e-fuels**. Over their lifetime, average European BEVs sold in 2030 would emit 51 gCO_2/km whereas the average e-petrol car is more than 80 gCO_2/km. If a combination of grid electricity and renewable electricity[19] is used to produce the e-fuel, the lifecycle emissions of a car with e-petrol would be 82 g/km while it would be 95 g/km for a combination of electricity from natural gas and renewables. Thanks to much lower overall electricity consumption, BEVs can perform better than e-petrol cars even when the carbon intensity of the electricity used to charge the car is higher than the one used to produce the fuel. By consuming five time more electricity for e-petrol even with a low lifecycle carbon intensity of the electricity used (between 66 gCO_2/kWh and 80 gCO_2/kWh) results in a situation whereby the total emissions accumulated over the lifetime of the vehicles can surpass those of a BEV running on more carbon intensive grid electricity (from 165 gCO_2/kWh in 2030 down to 56 gCO_2/kWh in 2040[20]).

[18] Transport & Environment (2020), *How clean are electric cars?* Link
[19] A combination of wind and solar is considered, based on the average expected mix between the two in 2030 (26% solar vs. 74% wind)
[20] ENTSO-E TYNDP 2020. For more see: Transport & Environment (2020), *How clean are electric cars?* Link



The electricity used to produce the e-fuel is based on the sustainability criteria from the REDII: 70% CO2 reduction compared to conventional fuels. In practice the electricity used to produce the e-fuel would be 70%-90% of additional renewable (depending if the renewable electricity is combined with gas or grid electricity).

Figure 5a: Lifecycle CO_2 emissions in 2030: BEV vs. e-petrol

Why are e-petrol lifecycle emissions higher when fossil gas power generation is combined with renewables rather than grid electricity?

Although both e-fuel production pathways here would meet the 70% RED II criteria, the difference between the two pathways comes from the fact that the WtW emissions from the grid electricity used in the methodology are calculated from two years prior to 2030, which means that actual lifecycle emissions of the electricity used to produce the e-fuel in 2030 are lower than the WtW emissions used to calculate the fuel emissions on paper. By using the 2028 figures and their higher carbon intensity due to a lower share of renewables compared to the situation in 2030, the e-petrol lifecycle emissions would be considered to be higher. The second reason comes from the fact that the share of renewables used to produce the e-fuels in combination with fossil gas power generation is higher (to compensate for higher emissions from fossil gas electricity versus average EU grid electricity). Hence the additional lifecycle emissions from renewables (when compared to zero emission renewables under the e-fuel sustainability production criteria) are more important because more of that renewables electricity is needed to produce the e-fuel when combined with fossil gas. On the other hand the difference between WtW and lifecycle emissions for fossil gas electricity production is much lower than for renewables, which means that the lifecycle emission scope brings a higher impact when the share of renewables is higher (for a given WtW sustainability criteria).

For comparison, in 2030, the petrol car running on conventional fuels would emit 192 gCO_2/km over its lifetime which is 2.0-2.3 times more than when running on e-fuels produced under the RED II sustainability criteria. In other words, powering a conventional car entirely on e-fuels only reduces life cycle CO_2 emissions by 51%-57%. In many cases the e-petrol would be blended with conventional petrol, leading to a lifecycle CO_2 emission performance which would sit somewhere between the 100% e-fuel values and the 100% conventional fuel value. For example, a petrol car running on a 50/50 e-fuel blend would reduce life cycle CO_2 emissions by 25%-29% (143-137 g/km).

The lifecycle CO_2 emissions of a BEV breaks even with an e-petrol car between 50,000 km and 80,000 km, which would be reached after around 3-5 years for the average driver. Figure 5b below shows the evolution of lifecycle emissions for e-petrol produced from both options presented above.

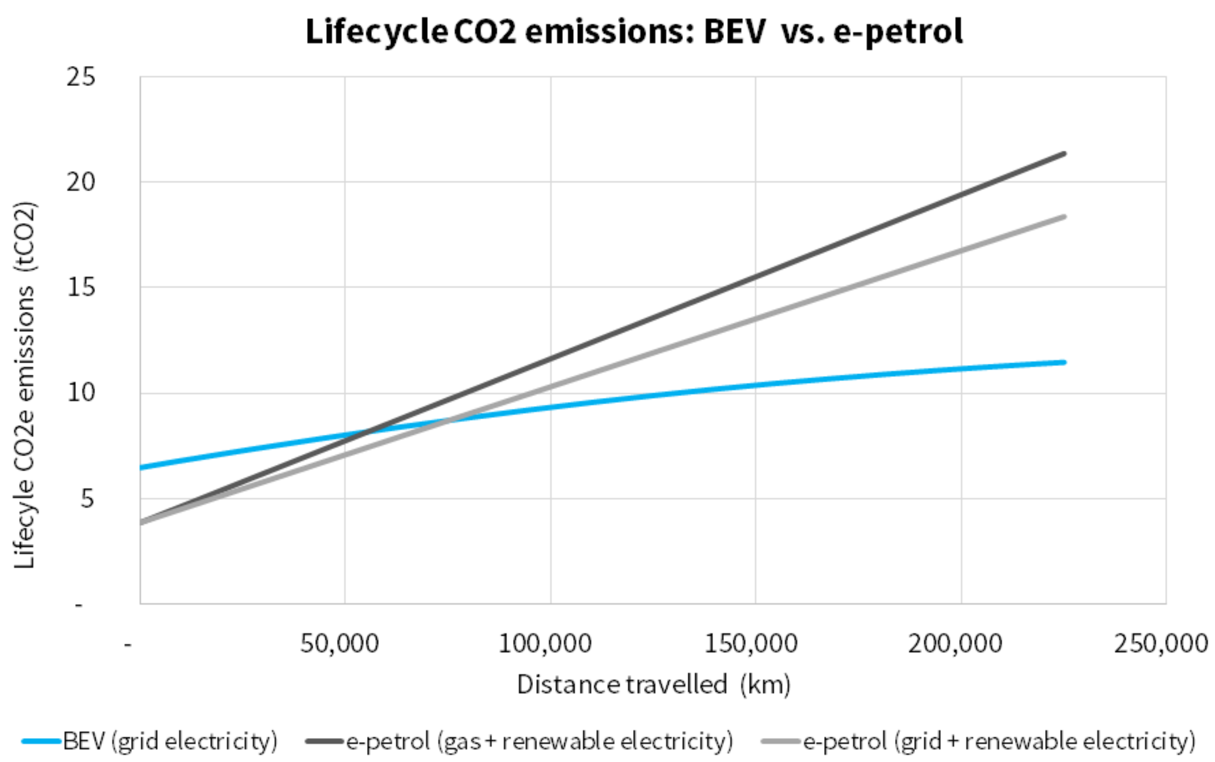
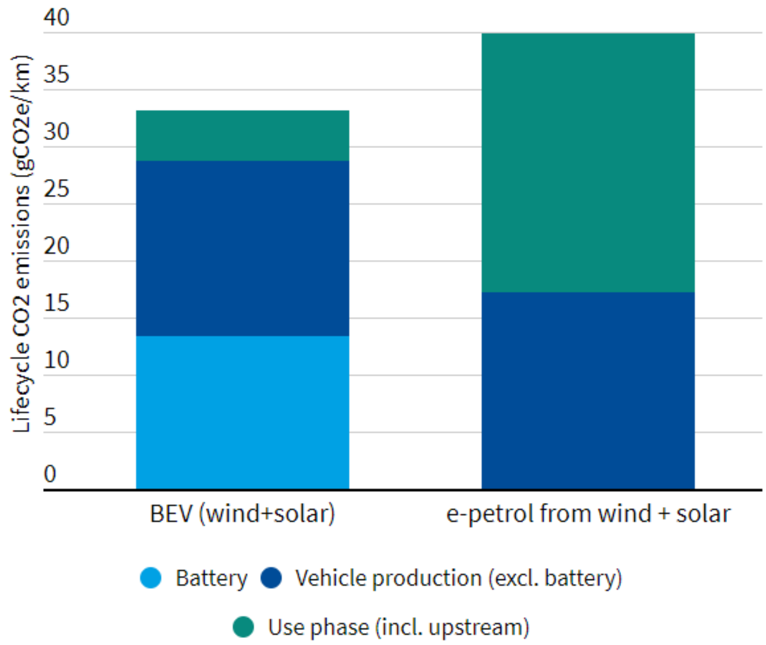


Figure 5b: Lifecycle CO_2 emissions in 2030: BEV vs. e-petrol (under RED II sustainability criteria)

For Germany - where there is a strong push for e-fuels to be part of the future cars mix - BEVs emit 28%-38% less CO_2 over their lifetime than e-petrol cars, while this drops to 60%-66% less for a BEV powered with renewables (e.g. electricity from Sweden).

The comparison presented above is nonetheless still favorable to e-petrol cars: synthetic fuels are assumed to be produced via an electricity mix which is almost fully decarbonised, whereas the electricity used to charge the BEV is based on the EU27 grid average, which still relies on close to a quarter of fossil fuel powered electricity in 2030 (mainly coal and gas) and is hence more than two times more carbon intensive. In the situation where the same electricity is used to produce the e-fuel and charge the vehicle[21], BEVs emit around half the emissions than a comparable e-petrol car (between 45% and 57%).

Even if 100% renewables electricity is used for efuels production[22], BEVs powered with the same mix are still much cleaner from the lifecycle emissions perspective, offering a 17% CO_2 reduction (33 g/km vs. 40 g/km), see Figure 6 below. This is explained by the fact that the lifecycle emissions of renewable electricity is not zero (primarily because of the production of the infrastructure), which means that by consuming a large amount of this electricity, the e-petrol powered cars can end up having a larger impact than the BEV even when we take into account the impact of the battery.



The same renewable electricity is used to power the BEV and to produce the e-fuel (mix of wind and solar based on the expected mix in 2030 according to ENSOE 2020 TYNDP electricity generation forecast)

Figure 6a: Lifecycle CO_2 emissions in 2030: BEV vs. e-petrol (100% renewables)

Figure 6b below shows the evolution of lifecycle CO_2 emissions when both the e-petrol and the electricity used to charge the vehicle are from renewable electricity.

[21] Lifecycle carbon intensity of the electricity: 56 gCO_2/kWh
[22] Assuming only Wind + Solar PV, based on the 2030 split from ENTSO-E TYNDP 2020. Lifecycle carbon intensity of the electricity: 23 gCO_2/kWh

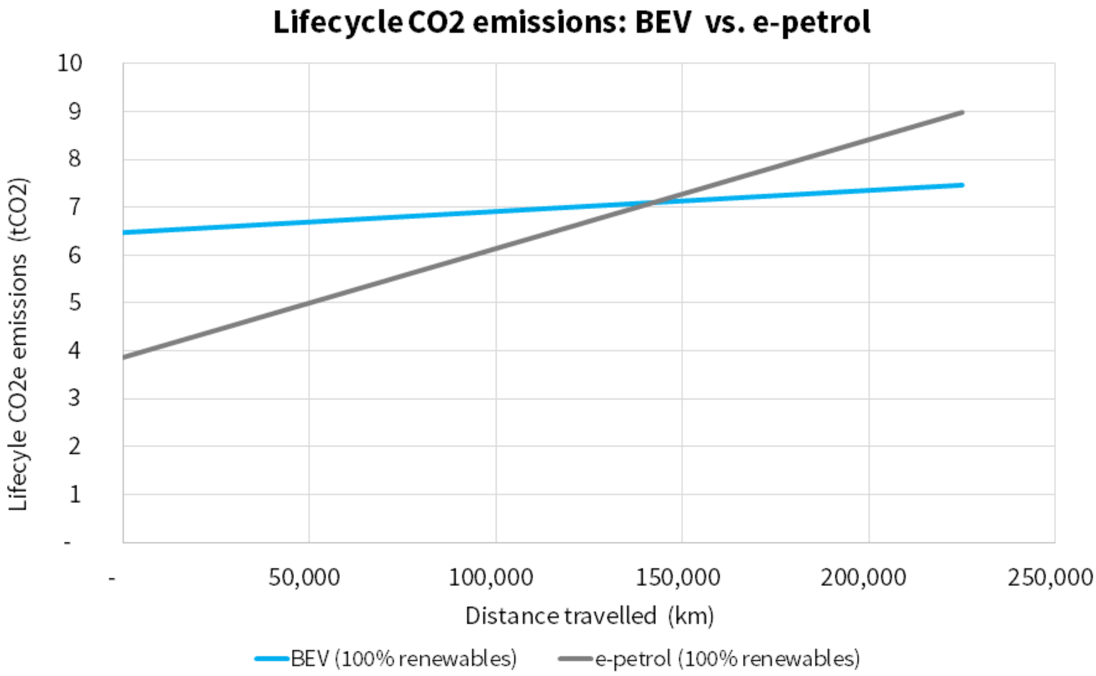


Figure 6b: Lifecycle CO_2 emissions in 2030: BEV vs. e-petrol (100% renewables)

Even in the hypothetical situation where e-fuels would be available today and the e-petrol car would be compared to a BEV running on today's electricity grid, the BEV would still be between 21% and 32% cleaner than the e-petrol car over the lifetime of the vehicle. This situation is however purely hypothetical given that such e-fuels do not exist today. Nonetheless, the finding highlights that -even before the 2030s- e-fuels cannot be a credible solution to reduce emissions. Over the years, as more renewables are incorporated into the electricity mix, the comparative advantage of BEVs over e-petrol cars only gets stronger.

In conclusion, under the current sustainability threshold for synthetic fuels (and assuming the most optimistic methodology for the calculator of the threshold), **conventional cars powered with e-fuels consistently emit more CO_2 than an equivalent BEV.** This result holds true even in the situation where the e-petrol is produced only with renewables and compared to a BEV running on renewables as well. The results are clear, using **e-fuels to power conventional cars cannot provide any considerable climate benefits in the context of widespread adoption of BEVs**.

4. Availability: e-fuels should not be diverted to cars where better alternatives exist

A recent study undertaken by Ricardo and commissioned T&E (December 2020)[23], has found that there is no scope to use renewable electricity inefficiently. Enabling the use of synthetic hydrocarbons in road

[23] Transport & Environment (2020), *Electrofuels? Yes, we can … if we're efficient.* Link

transport, where technical alternatives such as the direct use of electricity exist, comes with a huge energy penalty and risks derailing the entire decarbonisation effort.

The results of the study shows that relatively small variations in the use of hydrogen and efuels can add up can add up to large differences in terms of the renewable energy that will need to be produced. For example, if 100% of passenger cars were battery-electric, charging them would require 417 TWh in 2050 (just 15% compared to current total electricity demand). Enabling only 10% hydrogen plus 10% of synthetic hydrocarbons in cars would push up demand to 598 TWh or a 43% increase.

Inefficient use of e-fuels also results in a significantly higher area requirement. Delivering the energy needed for the synthetic fuel scenario would require an area equivalent to 5.1 times the area of Denmark if offshore wind would supply all of the additional electricity needed to decarbonise the transport sector (3.4 times in the base case). In other words, powering just a fraction of vehicles with e-fuels in 2050 would require new offshore wind-farms covering an area the size of Denmark.

With the whole economy relying on renewables, *'efficiency first'* matters given the large impact it can have on the renewable electricity requirement. Therefore, using less renewables is also most optimal as regards cost-effectiveness towards the energy system. Furthermore, there isn't expected to be any volumes of synthetic fuels on the market until after 2030[24], by which time plug-in cars will be by far the most efficient, cheap and convenient option.

The outlook is clear, **promoting even a limited use of synthetic fuels in road transport now will lock the EU's transport decarbonisation in a pathway that will require a much greater deployment of renewables than necessary**. This makes the transition harder to accomplish and could complicate the decarbonisation of the long-distance transport modes like aviation and shipping (which cannot use batteries to decarbonise).

5. Car CO_2 regulations: do not include fuel credits

On top of the strong economic, environmental, efficiency and availability arguments presented in this briefing, including e-fuel credits into the car CO_2 regulation cannot either be justified from the regulatory perspective. Indeed **carmakers cannot guarantee how cars are used or fueled over their lifetime**. They have no direct control over the choices of drivers and the suppliers' production processes. The vehicle regulation should only regulate what carmakers have control over, i.e. powertrains. Fuels should be regulated in appropriate EU legislation - as is the case already - such the EU Renewable Energy Directive and the EU Fuel Quality Directive. Thus keeping both sectors separate would maintain the effectiveness of each legislation. The effectiveness of the current design of the car CO_2 regulation has been proven in 2020 as the new targets propelled the EV market from 3% in 2019 to 10.5% in 2020[25].

[24] Even with very strong policy support and subsidies the potential volumes of CO_2-based synthetic fuels would be limited to approximately 0.15% of total EU road transport fuel demand in 2030.
[25] Transport & Environment (2020), *CO_2 targets propel European EV sales.* Link

The very **credibility of the car CO_2 regulation could be undermined** as car manufacturers could buy their way into compliance without making any improvements. Based on the amount of credits bought, a certain number of conventional cars on the road would be considered zero emission in their eyes of the regulation. This would likely be perceived very negatively by the average European which has been asking for zero emission cars[26].

Finally including synthetic fuels in the car CO_2 regulation also opens the door to the inclusion of other so called 'low or zero emission fuels' namely biofuels. These fuels are more affordable than efuels and would thus further reinforce the loophole and create a huge incentive to increase the use of biofuels although they are currently 80% worse than diesel[27].

T&E recommends[28]: **No CO_2 credits to carmakers for alternative or synthetic fuels should be included into the cars and vans CO_2 standards.**

Further information

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[26] Transport & Environment (2021), *Almost two in three European city dwellers want only emission-free cars aer 2030.* Link
[27] https://www.euractiv.com/section/agriculture-food/news/scientists-demand-end-to-crop-based-biofuels/
[28] Transport & Environment (2020), *Cars CO_2 review: Europe's chance to win the emobility race.* Link

6. Assumptions

General assumptions

Vehicles assumptions for a medium car (C-segment) in 2030

	BEV	Petrol	Source/comment
Fuel consumption (real-world) - 2030	0.17 kWh/ km	6 L/100km	Based on average values observed today for the BEVs. For the ICE, today's observed values. The value for petrol corresponds to today's hybrids (optimistic)
Fuel consumption (real-world) - 2025	0.173 kWh/km	6.5 L/100km	
Vehicle cost (2030)	22,200 €	27,200€	Cost trends are derived from (unpublished) study from BNEF (commissioned by T&E). The starting point is the (weighted) average vehicle cost of top selling vehicles in 2020[29]
Vehicle cost (2025)	28,000 €	26,100€	

Lifetime mileage: 225,000 km based on the European Commission study on LCA[30]. On average this is 15,000 km per year over 15 years[31]. No battery replacements are needed during the lifetime of the vehicle, in line with European Commission methodology and latest evidence[32].

Cost assumptions

Electricity prices are based on EU average 2020 (first semester) electricity costs from Eurostat and assumed constant up to 2030: 0.21€/kWh (0.13 €/kWh excluding taxes and levies)[33]

Conventional fuel prices are based on 2020 EU averages from the Oil Bulletin: petrol at 1.46 €/L (0.59 €/L without taxes) and diesel at 1.29 €/L (0.59 €/L without taxes). Taxes and levies account for 0.86 €/L for petrol and 0.70€/L for diesel.

Fuel price (including production, transport, distribution, taxes and levies)	Low		Central		High	
	2025	**2030**	**2025**	**2030**	**2025**	**2030**

[29] 2020/21 average: 34,500€ for BEVs and 25,400€ for petrol cars
[30] Ricardo Energy & Environment (2020), *Determining the environmental impacts of conventional and alternatively fuelled vehicles through LCA. Final Report for the European Commission, DG Climate Action.* Link
[31] In the LCA analysis and when calculating the average cost of e-fuel credits over the lifetime of a vehicle, the activity is assumed to decrease by 3% per year.
[32] Transport & Environment (2020), *How clean are electric cars?* Link
[33] Electricity prices for household consumers - bi-annual data (from 2007 onwards) [NRG_PC_204__custom_632753]. Band DC.

E-petrol	2.3	2.0	2.5	2.3	2.7	2.5
E-diesel	2.3	2.0	2.5	2.3	2.8	2.6

Other assumptions for the TCO calculation are listed below (for more details see T&E study on the cost of Uber[34]):

- Ownership period 5 years
- Maintenance cost: 300€ per year for the petrol cars and a reduction of 50% for the BEV.
- Residual value: 40% residual value after 5 years.
    - For a second hand ICE car bought in 2025, it is assumed that the residual value after 10 years (in 2035) is zero given the age of the vehicle and the strict limitation of petrol and diesel cars in cities (Euro 7 emission standard is not likely to be enforced by 2025, which makes these vehicles vulnerable to air quality restriction). In 2035 buyers would likely not choose a more expensive option which limits their ability to enter cities[35], thus driving down the residual value.
    - For second hand BEVs bought in 2025, the residual value after ten years is assumed to be 10% of the original price.
- No purchase subsidy or additional annual/circulation taxes were included in this assessment (conservative given increasing deployment of circulation taxes for ICEs in cities).
- Charging infrastructure:
    - Costs of home charger installation are factored in for the BEVs and estimated at €1,500 installation costs included. The cost of the charger is paid upfront and included in the 'others' cost category in the TCO infographic.
    - 5% of the energy is assumed to be delivered at fast public charging stations at 0.40 €/kWh.
- Financing:
    - Purchase option: the TCO model includes parameters linked to the vehicle acquisition mode (purchase, lease, or loan). The three scenarios impact the TCO only marginally; in the report all vehicles are assumed to be purchased, as this corresponds to the mid-price scenario. Cost effectiveness of BEVs vs. ICE can be improved by using leasing schemes, but deteriorates with loans.
    - Discount rate: 4%
    - Insurance costs: 3.5% of the vehicle upfront cost (annually). The insurance cost for 2nd hand cars was assumed the same as for 1st hand cars

Compliance pathway costs assumptions

- Fuel efficiency (real world): 7L/100km in 2020/2, 6.5 L/100km in 2025 and 6L/100km in 2020 (in line with a 1.5% annual improvement per year).
- BEV battery: 60 kWh
- Battery costs: 74€/kWh in 2025, 51 €/kWh in 2030 (based on BNEF battery price projection)

[34] https://www.transportenvironment.org/publications/why-uber-should-go-electric
[35] Indeed, by 2025, it is unlikely that new Euro 7 standards would be enforced which means that those vehicles could be subject to high restrictions

Social cost assumptions

Assumptions for the share of revenue in e-fuel and battery production which flow back to (or stay within) Europe (authors assumptions).

- Electricity cost of hydrogen electrolysis: 10% (allocated to RES and utility industry)
- Cost of conversion of hydrogen electrolysis: 30% (allocated to hydrogen industry)
- Storage cost for hydrogen: 30% (allocated to hydrogen industry)
- CO_2 cost: 30% (allocated to fuels industry)
- Investment cost: 30% (allocated to fuels industry)
- Operating cost: 30% (allocated to fuels industry)
- Battery: 65% (allocated to the battery production industry)

Lifecycle CO_2 emission analysis

In the LCA analysis of e-fuels, T&E assumes that the 70% sustainability criteria under REDII for the production of synthetic fuels is based on the WTW emissions from the different energy sources. If the final methodology adopted by the European Commission (due by the end of 2021), decides to use the wider lifecycle scope and accounts for infrastructure emissions (i.e. renewables are not counted as zero), then lifecycle CO_2 emissions from conventional cars powered with e-fuels would be slightly lower (between 12% and 25% lower depending if fossil gas or grid electricity is used in combination of renewables). This is explained by the fact that a higher share of renewable electricity would be needed to reach the 70% sustainability criteria and balance off the higher emissions from electricity from natural gas or grid electricity given they are not counted as zero emissions. This option is not presented in this paper.

The well to wheel emissions for petrol and diesel fuels used as a reference for the European Commission is of 94 gCO_2/MJ. Therefore, the maximum lifecycle CO_2 emission from e-petrol and e-diesel fuels under the REDII 70% criteria would be 28 gCO_2/MJ.

T&E modelled different scenarios for the electricity sources that can be used in e-fuel production and their respective shares in the electricity used. The WTW and lifecycle carbon intensity of each electricity supply technology is based on IPCC's Fifth Assessment Report[36].

All other assumptions used in the LCA modelling are presented in T&E's lifecycle CO_2 analysis report 'How clean are electric cars?'[37], with the exception of the following updates:

- The petrol car fuel consumption was set at 6 L/100km in 2030 (see above, General assumptions).
- The BEV energy efficiency was set at 17 kWh/km in 2030 (see above, General assumptions).
- The lifecycle emissions of the electricity mix in 2020 was updated based on recent evidence from Ember[38]. Direct CO_2 emissions from Ember in 2020 are 226 gCO_2/kWh (EU27) while T&E

[36] Intergovernmental Panel on Climate Change, IPCC (2014), Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the IPCC - Annex III. Link. Median values assumed

[37] Transport & Environment (2020), *How clean are electric cars?* Link

[38] Ember (2021), *EU Power Sector in 2020.* Link

calculates life cycle CO_2 emissions at 285 gCO_2/kWh (without transmission and distribution losses).

- Battery production in 2030: The upstream emissions from battery production (ie steps before the cell production and pack assembly) will decrease in the next decade thanks to the overall decarbonisation of the world economy. T&E assumes that the carbon intensity of the upstream stage of battery production is reduced by a quarter between 2020 and 2030. This is approximately half of the world or European improvement of the carbon intensity of electricity[39]). This effectively brings down the carbon footprint of batteries produced in the EU to 50 $kgCO_2$/kWh in 2030 (upstream accounting for 41 $kgCO_2$/kWh out of 50$kgCO_2$/kWh).

[39] IEA (2020), *Carbon intensity of electricity generation in selected regions in the Sustainable Development Scenario, 2000-2040.* Link

Anlage 3

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Hitting the EV Inflection Point

Electric vehicle price parity and phasing out combustion vehicle sales in Europe

TRANSPORT & ENVIRONMENT

BloombergNEF

Contents

Section 1. EV price parity and phasing out combustion vehicle sales in Europe

$58/kWh

Expected average battery pack price in 2030

2025-2027

Years at which BEV prices reach parity with internal combustion engine vehicles in all light vehicle segments in Europe

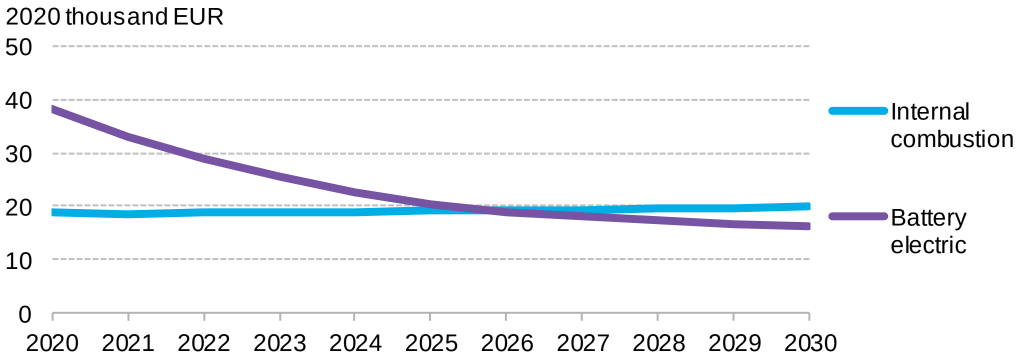
51%

Base case BEV share of light duty passenger vehicles sales in Europe in 2030

Electric vehicle sales are rising fast in Europe and a growing number of governments have set targets for phasing out new internal combustion vehicle sales. A fundamental input in deciding the feasibility of such policies is how quickly battery electric vehicles can reach price parity with their internal combustion counterparts. Further improvements in lithium-ion batteries will be critical and manufacturing strategy will also play a role. This report shows trajectories of cost developments for the production of battery electric vehicles and internal combustion engine vehicles, and the implications for the adoption of electric vehicles in Europe.

- Battery electric vehicles in all segments in Europe are expected to reach upfront cost price parity with equivalent internal combustion engine vehicles within the next product cycle. Falling battery prices and the development of optimized platforms lead the rapid decline in BEV costs. An optimal vehicle design, produced in high volumes, can be more than a third cheaper by 2025 compared to now. However, risks remain, primarily in achieving low enough battery prices and managing demand uncertainty.
- Battery technology continues to improve rapidly leading to lower prices and increased competition in Europe. New chemistries, better manufacturing methods, innovative cell and pack design concepts and other factors contribute to average prices per kilowatt hour declining by 58% from 2020 to 2030. There is visibility into how those declines can be achieved up to the late-2020s. Beyond that, the technology roadmap expands with some concepts, such as solid-state, still emerging. Uncertainties throughout the period to 2035 include raw materials prices that can become volatile and cancel some gains, and the speed at which the supply chain can scale up rapidly and sustainably in Europe.

Figure 1: Estimated pre-tax retail prices for C segment vehicles in Europe



Source: BloombergNEF Note: includes only passenger cars; ICE is internal combustion engine vehicle and BEV is battery electric vehicle

- Electric vehicle sales are set to rise strongly in the short term to meet the upcoming CO_2 emissions target in Europe. By 2025, BNEF expects 4.3 million plug-in vehicles to be sold in Europe, representing around 28% of all sales in that year. BEVs capture over half of those plug-in vehicles sales, the remaining are plug-in hybrid vehicles, which are likely to become a significant compliance tool for several automakers. Across Europe, short-term adoption is highly uneven. Strong policy support and automakers' market strategies mean EV adoption in countries in the north and west of Europe far exceeds that of countries in the south or east.
- Battery electric vehicle adoption can be quick between 2025 and 2035. In an economics-driven scenario, Europe could reach just over 50% BEV share of sales by 2030 and 85% by 2035. Countries leading in EV adoption currently, such as those in the Nordics and the Netherlands, will remain in a leading position. Large automotive markets, such as Germany, the U.K. and France, will follow and will contribute the highest unit sales increase across Europe. In turn, countries starting from a low adoption position now are likely to end up further behind those other groups, but can experience rapid growth in the late-2020s. Still, achieving such high shares of BEV sales depends on vehicle prices coming down considerably in the next few years, consumers continuing to receive some purchasing support, and charging networks rolling out widely across Europe.

Figure 2: Base case and accelerated battery electric vehicle share of new passenger car sales in Nordics+

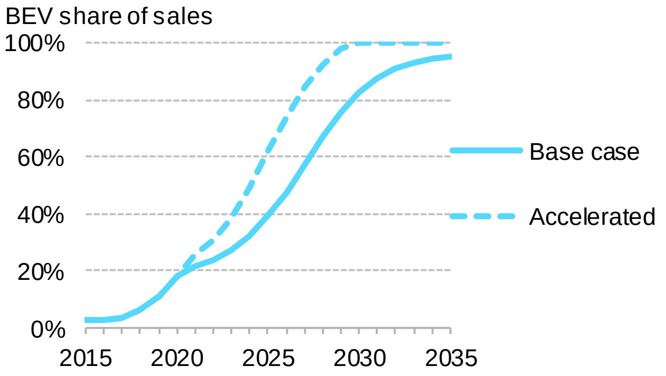


Figure 3: Base case and accelerated battery electric vehicle share of new passenger car sales in Western Europe

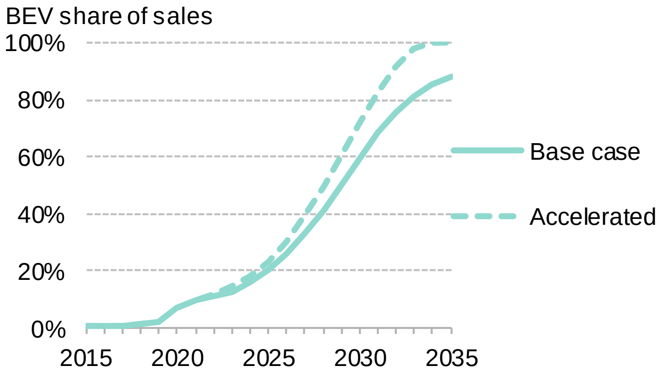


Figure 4: Base case and accelerated battery electric vehicle share of new passenger car sales in Southern Europe

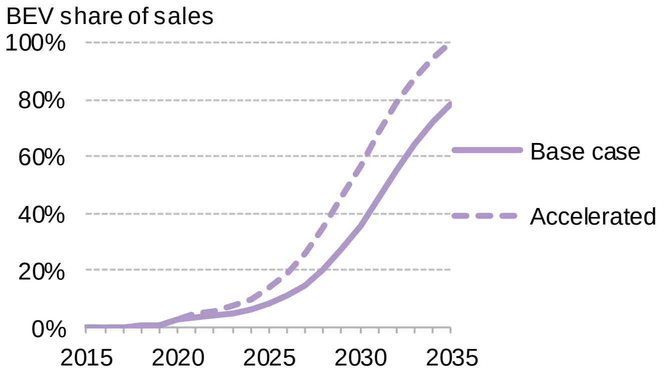
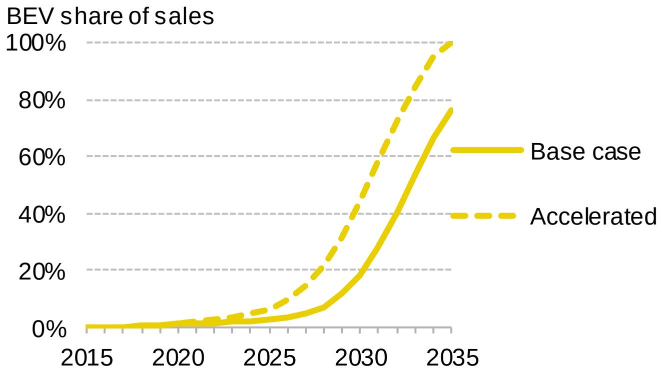


Figure 5: Base case and accelerated battery electric vehicle share of new passenger car sales in Eastern Europe



Source: BloombergNEF. Note: includes passenger cars only; includes adoption of battery electric vehicles (BEV) only; does not include plug-in hybrids (PHEV). Base case shows development trajectory under current technology outlook and policy measures. Accelerated shows potential scenario under additional stimulus.

- Even though organic BEV adoption is high by 2035, the EU and most countries would need to further expand their policy support frameworks to reach 100% adoption by 2035. A menu of options could include even tighter emissions rules, carbon taxes, subsidies for 'edge' use cases and extensive geographic coverage of charging networks. The accelerated scenario highlights the importance of the early buildup of BEV production and sales volume, as that drives cost reductions and also generates the necessary consumer buy-in for further adoption in the future.

This report was prepared by BloombergNEF for Transport & Environment.

BloombergNEF

About BloombergNEF

BloombergNEF (BNEF) is a strategic research provider covering global commodity markets and the disruptive technologies driving the transition to a low-carbon economy. Our expert coverage assesses pathways for the power, transport, industry, buildings and agriculture sectors to adapt to the energy transition. We help commodity trading, corporate strategy, finance and policy professionals navigate change and generate opportunities.

TRANSPORT & ENVIRONMENT

About Transport & Environment

Transport & Environment (T&E) is Europe's leading clean transport campaign group. T&E's vision is a zero-emission mobility system that is affordable and has minimal impacts on our health, climate and environment.

Since T&E was created 30 years ago, it has shaped some of Europe's most important environmental laws. It got the EU to set the world's most ambitious CO2 standards for cars and trucks but also helped uncover the dieselgate scandal; campaigned successfully to end palm oil diesel; secured a global ban on dirty shipping fuels and the creation of the world's biggest carbon market for aviation.

Section 2. Introduction and background

The global EV market

Sales of electric vehicles are rising quickly, driven by supportive policy, technology improvements, urban air quality concerns, and rising consumer awareness. Over 3 million passenger electric vehicles were sold in 2020, up 47% from 2019, and the market is set to grow rapidly again in 2021. The Covid pandemic has roiled auto markets around the world, with total passenger vehicle sales dropping 16% in 2020. EVs have been mostly immune to this due to additional policy support, and a wide range of new models hitting the market.

Figure 6: Global passenger EV sales by region

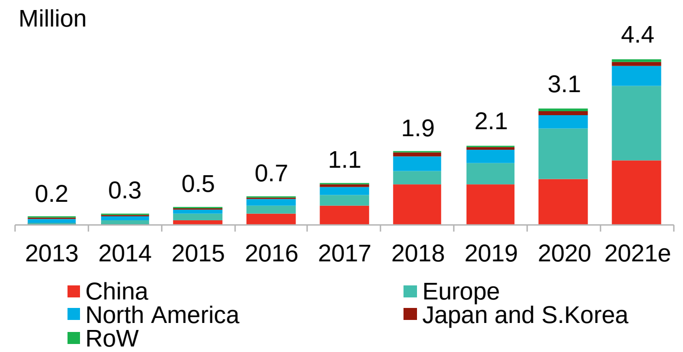
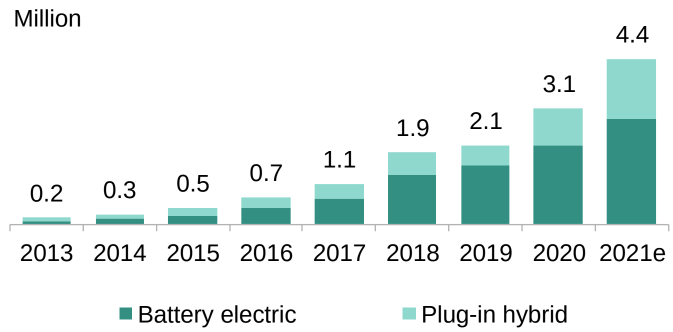
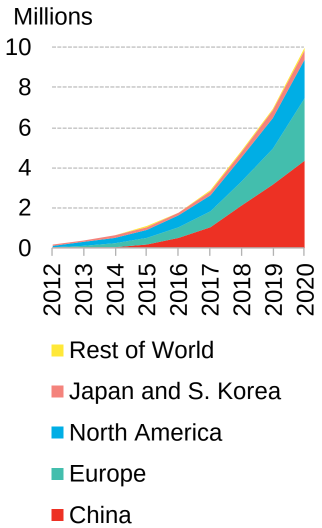


Figure 7: Global passenger EV sales by drivetrain



Source: BloombergNEF Note: EV are electric vehicles and include battery electrics and plug-in hybrids

Figure 8: Global passenger EV fleet



Source: BloombergNEF

China represented over 50% of global EV sales from 2017 to 2019, but that dynamic shifted in 2020 as EV sales in Europe more than doubled. Various policy mechanisms are being used to support this growth on both the demand side and the supply side. EV sales are slower in North America, but the Biden Administration is proposing $174 billion in investments to push the EV market forward, which, coupled with new fuel economy targets, could help close the gap with China and Europe. Battery electric vehicles (BEVs) form the majority of plug-in vehicles sold globally, though sales of plug-in hybrids (PHEVs) are rising quickly in Europe.

The total number of light-duty EVs on the road globally hit 10 million at the end of 2020, up from just 3 million in 2017. Electrification is also spreading into other segments of road transport and there are now over 500,000 e-buses in use. Commercial EV truck sales are still small, but there are nearly 350,000 on the road, mostly in China and Europe. Most of these are in the light commercial segment, though there is progress of electrifying larger vehicles. At the end of 2020, there were also around 190 million electric two-wheelers globally, including electric motorcycles, mopeds and scooters.

EV sales in Europe

The recent surge in EV sales in the EU is being supported by the new passenger car CO2 targets, which require automakers to reduce their overall fleet emissions to 95gCO2/km in 2020/21. As a result, automakers have launched many more EV models and increased production. More than 1 in 10 new vehicle sales in the region in 2020 had a plug. Only 95% of car sales were included in this target in 2020, but 100% will be included in 2021, leading to higher levels of EV adoption.

The CO2 targets are set to tighten again in 2025 and 2030. The current targets are set at a further 37.5% reduction from 2021-2030, but this is expected to be reduced further to keep the auto sector in line with the European Commission's Green Deal and its overall target of making Europe climate neutral by 2050. Many national governments also have demand-side incentives and fiscal policies in place to help stimulate EV adoption. EV sales have held up much better than combustion vehicle sales in Europe during the Covid-19 pandemic.

Passenger EV adoption varies widely between different European countries. In 2020, Germany was by far the largest EV market in Europe, with absolute EV sales in the country two times higher than in the next two largest markets, France and the U.K. The highest EV adoption shares are in the Nordics and the Netherlands, and EVs exceeded 10% of sales in a total of 12 countries in 2020. EV adoption has generally been slower in Southern and Eastern Europe.

Electric van sales were just under 2% of the total market in 2020. The sector has suffered from low model availability, with relatively expensive electric offerings, and a lack of widely accessible charging solutions for small and medium-size fleets. This situation is shifting, as both startups and established automakers are introducing new electric models with good enough range and cargo capacity to match different use cases.

Figure 9: Europe EV share of new passenger vehicle sales

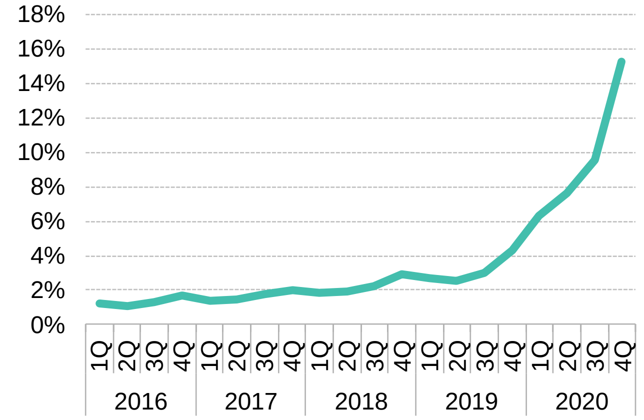
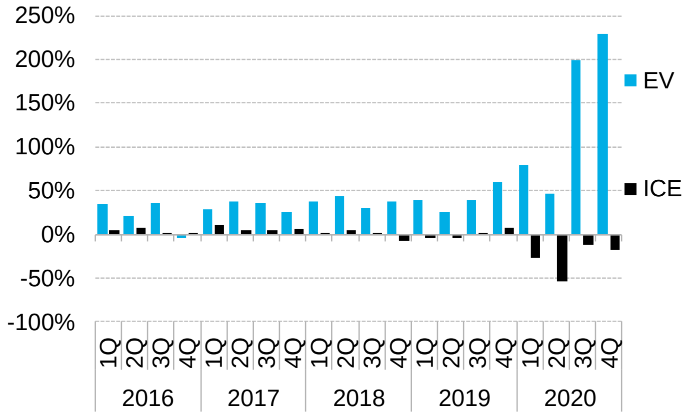


Figure 10: Europe passenger vehicles sales year-on-year change



Source: BloombergNEF, Marklines, Bloomberg Intelligence, vehicle registration agencies, EV Sales Blog, EAFO. Note: Europe data includes EU27 countries plus Norway, Switzerland, Iceland and the U.K. EV sales include BEV and PHEV sales. ICE = internal combustion engine.

Technology improvements

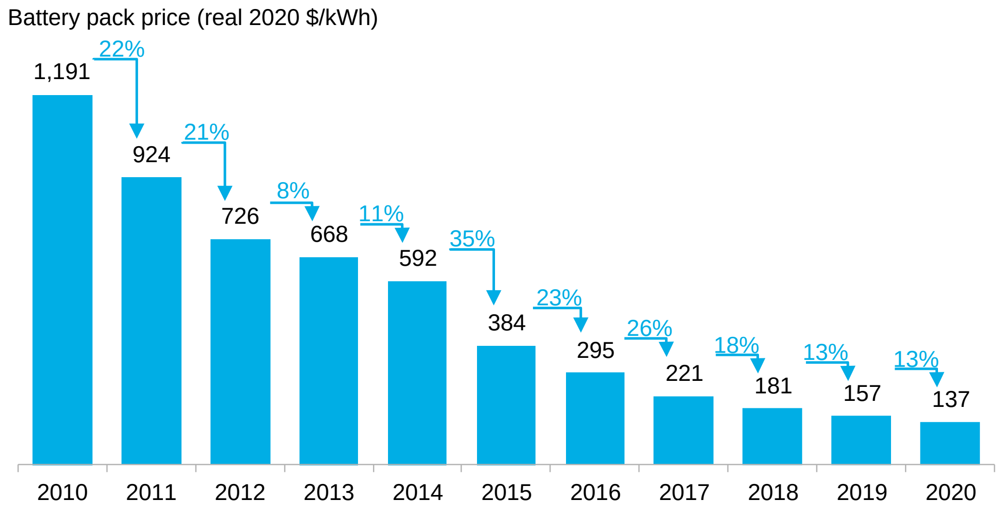
Falling prices for lithium-ion batteries are the biggest technology driver supporting the rapid rise in EV sales. Average lithium-ion battery pack prices fell 13% in 2020 and are now down 89% from 2010-20. While there is significant variation between applications, the average lithium-ion battery pack now costs $137/kWh and cells have already dropped to just over $100/kWh. Average lithium-ion battery pack energy density going into EVs has also been improving at 7% annually over the last 10 years.

Plug-in hybrid battery packs are more expensive on average, with prices of around $359/kWh 2020. In PHEVs, cells need to be balanced between power and energy. This is because packs need to be able to carry a vehicle a reasonable distance on battery power alone, while also providing the same peak power output as a BEV, and recovering energy under high-power situations, such as from regenerative breaking.

Battery material costs are currently rising, with prices of lithium carbonate, lithium hydroxide and cobalt rising 72%, 47% and 58%, respectively, in the first quarter of 2021. Despite this, BloombergNEF expects global volume-weighted average battery pack prices to cross $100/kWh by 2024.

Other EV technology improvements being implemented include using batteries as a structural element of the vehicle (sometimes referred to as ‘cell-to-chassis’), higher efficiency electric motors, and better integration between EV components.

Figure 11: BloombergNEF lithium-ion battery price survey results



Source: BloombergNEF

Phasing out combustion vehicle sales

As EV sales rise and battery prices continue to fall further, a growing number of governments have set targets for phasing out new internal combustion vehicle sales – including the biggest car markets in Europe like France or the U.K. However, the feasibility and optimal timing of these is still debated. The most important factor is likely to be how quickly battery electric vehicles can reach price parity with their internal combustion counterparts. Further improvements in lithium-ion battery performance, energy density and cost will play a large role in determining this, but other components, vehicle manufacturing processes, and other factors will also play a role.

Automakers are also increasing their ambitions here. In 1Q 2021 alone, four automakers announced new plans to phase out sales of combustion vehicles. Three of them are global targets: the Jaguar brand is aiming to sell only EVs by 2025, Volvo is aiming for 2030, and GM is aiming for 2035. Ford’s plan is regional: it will sell only EVs in Europe from 2030. VW also announced a new target for 70% of its sales in Europe to be fully electric by 2030. Other automakers have also committed to long-term ‘net zero’ targets including Daimler, VW, Renault, Honda and Toyota.

Most analysis on phasing out internal combustion vehicle sales to date has focused on either a single vehicle segment, or a single country, and has often used outdated battery price forecasts. There is now general agreement that price parity will be reached in the 2020s, but the actual point varies significantly by segment and geography, and most countries have very different starting positions on EV adoption. This has big implications for policy makers, who are trying to determine when and how ICE phase-outs might be achieved.

This report aims to address these shortcomings in the previous analysis the European context and answer the following questions:

- In what year will BEVs reach prices parity with comparable ICE vehicles in Europe and how does this vary by segment?
- What are the main drivers of these parity points and how sensitive are they to changes in input assumptions?
- What is the outlook for BEV adoption in Europe, and how does this vary between regions?
- What is a potentially feasible phase-out date for new ICE vehicle sales in Europe and what are some of the additional policy measures that would be needed to achieve this?

Methodology and approach

The analysis in this report is based on public and proprietary datasets, expert interviews, BNEF's in-house expertise and proprietary models. These models include BNEF's Bottom-up Battery Cost Model, Vehicle Economics Model and EV Adoption Model. For more details on methodology, please refer to sections 3.2, 4.2 and 4.3.

Section 3. Analysis of Vehicle Price Parity

3.1. Background and context

Declining battery prices and, in the European market, strict CO2 emissions targets for 2025 and 2030 mean that adoption of electric vehicles is set to continue increasing rapidly in the 2020s. However, electric cars (EVs) can currently cost about a third more than equivalent internal combustion engine (ICE) vehicles. As the exact timing of consumer demand is uncertain, automotive manufacturers are facing hard decisions regarding their product and manufacturing strategies for the current decade.

One of the main decisions revolves around the speed at which automakers should switch their supply chains, industrial footprint, manufacturing base, and intellectual capital over to electric vehicles, and the magnitude of the required change. More specifically, one of the fundamental considerations involves the affordability of electric vehicles. In BloombergNEF's view, a mass market for unsubsidized EVs is only possible once they are cost competitive with equivalent ICEs.

This part of the report presents a price outlook for battery electric vehicles (BEVs) in Europe, as well as the different cost drivers and manufacturing approaches that are part of achieving those prices. The analysis includes ICEs and BEVs in different segments (Table 1 and Table 3) and presents trajectories of estimated pre-tax retail prices by 2035. One metric typically used for the economic competiveness of BEVs is the price-parity year – ie, the year at which BEVs cost the same to manufacture and sell as equivalent ICEs. Despite the popularity of this metric, which is also included in the results below, there are limits to the value that a single year can provide. For more details on that and, primarily, on the wider implications of these price trajectories to EV adoption in Europe by 2035, see Section 4.

Table 1: Vehicle segments considered in this report

Segment	Examples	Market share in EU27+U.K. in 2019	Average or typical retail price in 2019 (EUR)
B	Renault Clio	18%	15,900
C	VW Golf	23%	23,200
D	BMW 3 Series	6%	36,400
SUV-B	Honda HR-V	37%	28,800
SUV-C	Toyota RAV4		
SUV-D	Volvo XC60		
Light van	Renault Kangoo	25%*	19,200
Heavy van	Ford Transit	56%*	38,400

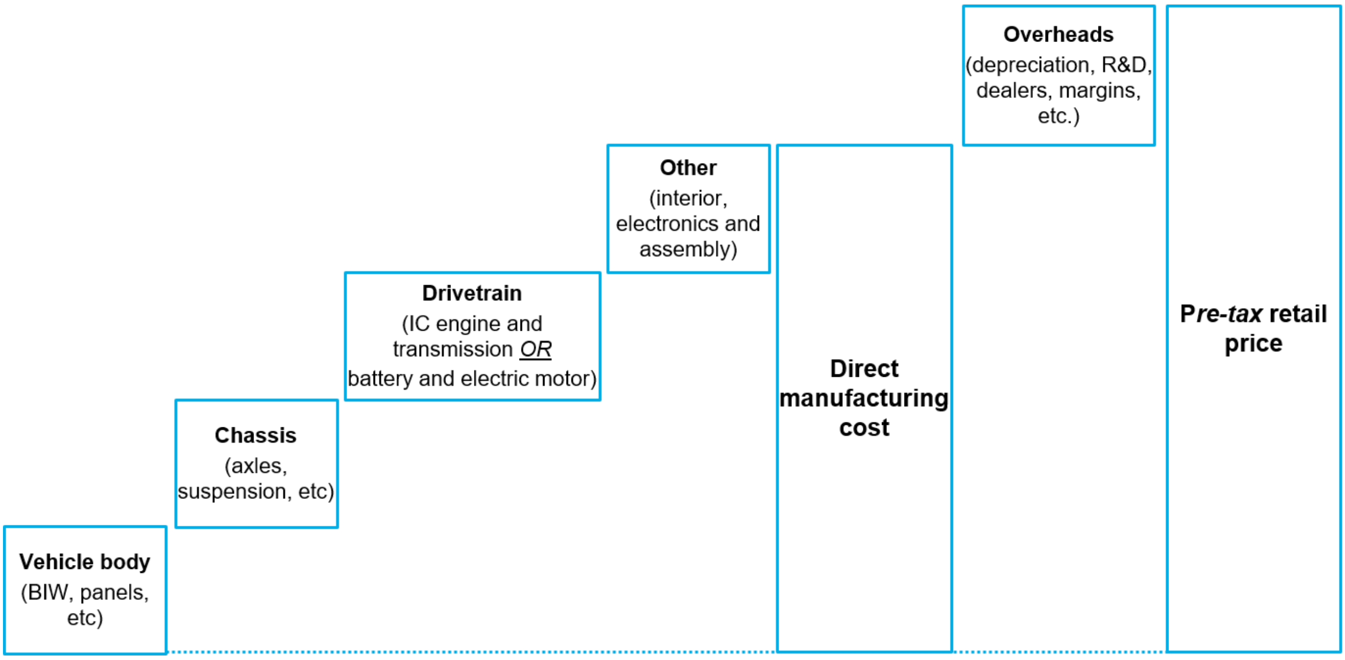
Source: BloombergNEF, ICCT, MarkLines, EU Commission, ACEA. Note: retail prices exclude tax, assumed at 20%. Van shares are share of light-duty commercial vehicle market.*

3.2. Methodology

The pricing methodology presented below is a cost-based approach and consists of deriving the direct manufacturing costs of various vehicle systems, and then adding the associated indirect costs (Figure 12). Direct manufacturing costs (DMC) include materials, labor, energy, building and machinery costs directly employed in the production of components. Costs such as depreciation or capital expenditure, research and development, marketing, transportation and distribution, warranties, profits and others are included in the production and corporate overhead costs.

Our modeling focuses on underlying production costs, while pricing can be a strategic choice made by automakers to manage supply and demand. Price parity will theoretically be achieved when an automaker can make and sell an EV with a comparable margin as a similar ICE model, without subsidies.

Figure 12: Vehicle cost methodology



Source: BloombergNEF

Baseline and optimized battery electric vehicles, and central scenario

We estimate two sets of production costs for BEVs. In the baseline case, we assume that vehicles are developed and manufactured using engineering platforms modified from existing ICE vehicles. In the optimized case, BEVs are designed and produced based on dedicated platforms (Table 2, and explanation box at the end of this subsection).

We combine those cost sets to derive our central pricing scenario, based on the manufacturing strategies of major automakers in Europe. We use this scenario in the price parity analysis and adoption forecasts. We estimate that in 2020, electric vehicle prices are heavily skewed toward the costlier baseline case, since many BEVs currently on sale are built on modified platforms. However, the weighting quickly shifts as several automakers develop dedicated platforms. We expect that by 2025 most BEVs available will be built on dedicated platforms.

Baseline electric vehicles may cost 10-30% more to manufacture and sell, depending on segment. The cost gap is primarily a result of different production volumes, mostly through lower battery costs. The distribution of the considerable development costs to more vehicles and more efficient inventory management are additional benefits. A second volume-related effect specific to BEVs is that dedicated all-electric platforms can in principle be used to build vehicles in several widely different segments. That is in contrast to existing ICE platforms, which can typically only accommodate vehicles on adjacent segments.

Dedicated platforms also offer possibilities for the engineering optimization of BEVs, such as better weight distribution and more opportunities for lightweighting, simpler assembly and specifically re-designed components, including axles and suspensions.

The main drawback of developing a new platform is demand uncertainty. The costs, the development timescales and the lifetime of automotive industrial assets make such decisions challenging. On the cost side, R&D expenses may well exceed 5 billion euros for a new platform, with additional capital expenditure needed to re-tool plants and other costs required to establish solid supply chains. The resulting manufacturing footprint needs to be fully utilized in order to recoup those investments, while timescales can be long. It can take three to five years to develop from scratch a new platform, which can be used for five to seven years. It can take an additional one to two years in strategy deliberations before taking a decision to even begin development. So, a manufacturer that may have started thinking of new EV platforms in 2020, should be relatively confident of sales volumes even into the early 2030s[1].

In the current European automotive market, regulation offers some counterbalance for those inherently risky decisions. Specifically, the tailpipe CO2 emissions targets for 2025 and 2030 provide demand anchors for electric vehicles, as automakers need to introduce BEVs and PHEVs in large numbers to meet those targets. We believe that the European Commission is likely to tighten them further in the future. Hence, we expect that in the second half of the 2020s most manufacturers in Europe will have developed dedicated EV platforms or lease/contract these from other suppliers. In our results, about three quarters of BEVs sold in Europe in 2025 are based on such architectures. Manufacturers will have ever stronger incentives to base more output on dedicated platforms, as BEV volumes rise over the next few years. By 2030, we assume that all BEVs will come out of dedicated platforms to take full advantage of the cost advantages of high volume manufacturing. Still, there are fundamental uncertainties in making such decisions and we treat those as part of the price sensitivity analysis.

Vehicle platforms and production volume

A platform is the set of component designs, manufacturing equipment, production processes and even supply-chain relationships that can be shared between different vehicles. Two of the main benefits of a platform are the opportunity for high-volume manufacturing of individual components and the ability to relatively quickly introduce new vehicle models and adapt to changing consumer demand. Typically, ICE platforms can be used for vehicles in two to three adjacent segments and they have a lifetime of about five to seven years. Initial BEV designs used modifications of such platforms.

Dedicated BEV platforms from incumbent manufacturers have only recently appeared and, in principle, can accommodate vehicles across more segments. As the development of a brand new platform may require more than 5 billion dollars, building vehicles from many segments on a single platform could provide scale benefits to manufacturers.

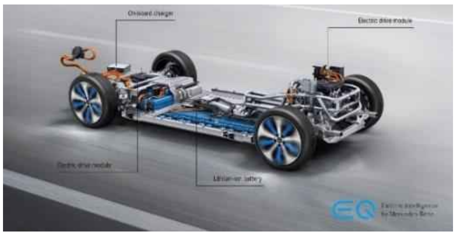
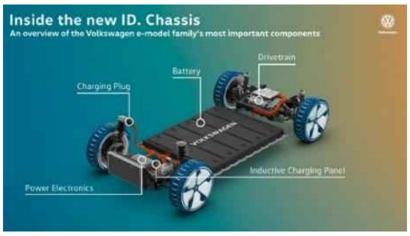
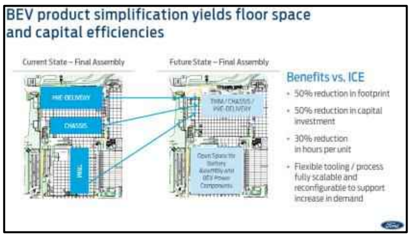
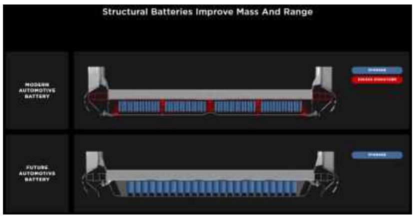
Some manufacturers are developing multi-energy platforms, which can support the development and production of vehicles with several powertrain technologies, including both

[1] There are indications that the development timescales of electric vehicles may be on the shorter end of that range, while the expected accommodation of more vehicle segments on a single platform may offer some flexibility to adapt to demand variations. However, the main thrust of the argument – that of high upfront investments and long timescales – remains.

combustion engines and batteries. These purpose-built platforms may not get the entirety of benefits of dedicated ones, but are a huge improvement over modified platforms.

The tradeoffs involved in a platform strategy are several, but the overarching consideration is the expectation of future demand. Those companies developing dedicated BEV platforms are more invested in an electric future, whereas those with multi-energy platforms value more the flexibility they offer in an uncertain future vehicle market.

Table 2: Battery electric vehicle development and manufacturing strategies

Approach	Examples	
Current: BEV designed from the ground up, using modified ICE platforms (eg, Bolt, iPace, EQC, Ioniq, Peugeot 2008). This is our *baseline case*, representing the majority of BEV models in the market now and in the short term.	Daimler's EQ platform 	
Dedicated platform: entirely new platform and manufacturing processes designed and developed for BEV (eg, ID.3, Model Y). Currently under development by Daimler, Hyundai, GM, Ford, and others. This is our *optimized case* and our expectation for the market norm around the mid-2020s.	VW's ID. platform 	Ford's approach 
Next generation: tighter integration of the battery and the vehicles – eg, Tesla's most recent announcement. Still unproven.	Tesla's latest announcement on 'cell-to-chassis' design, whereby the battery pack becomes an integral, even structural, part of the vehicle. This has the potential to save costs on materials, but could potentially make repairs more expensive. The concept has not been yet tested in a production vehicle. 	

Source: BloombergNEF

Battery pack improvements

Over the next decade, the introduction of more refined BEV pack architectures will continue to drive down prices (Figure 13). However, the rate of adoption of these new architectures will vary significantly across the industry.

Automotive companies like VW and GM are now adopting their second-generation pack designs. These are designed specifically for EVs, they can be adapted for multiple vehicles and are simpler to mass produce than first-generation packs. These designs are centered around standardized modules that can use a variety of different cell formats and chemistries.

In the long run the role of the cell will become more important in BEVs and the role of the pack will diminish. However, the timeline for this will vary by company and moving more slowly along this path does not necessarily mean that a company will be at a disadvantage. A more advanced architecture may be less reliable or harder to manufacture. There may also be limitations around the chemistry or cell format that can be used.

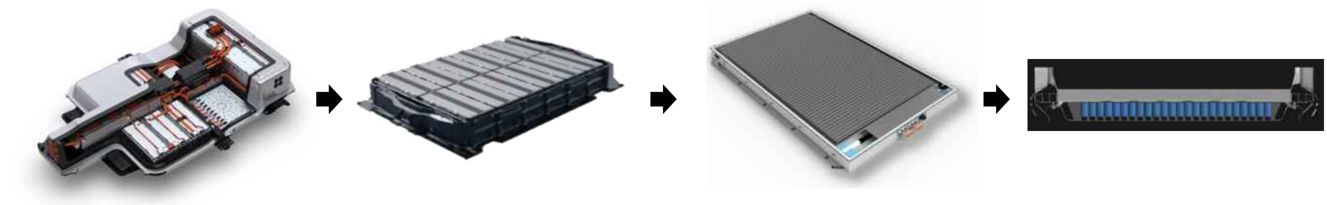
Figure 13: Evolution of battery pack design

ICE/BEV architecture, 1st generation **Example**: VW's e-Golf pack

BEV architecture, 2nd generation **Example**: GM's Ultium platform

BEV architecture, 3rd generation **Example**: BYD's Blade Battery

BEV architecture, 4th generation **Example**: Tesla's cell-to-chassis platform



Source: Volkswagen, General Motors, BYD, Tesla

Chinese automotive companies are already adopting third-generation pack designs. BYD's new Han EV uses the company's blade battery technology, which eliminates the need for modules and uses fewer cells. The company claims this approach reduces the pack price by as much as 30%. For the moment, this pack uses LFP batteries, which means that despite the lower cost the range of vehicles will still be lower than EVs using second-generation packs of an equivalent kWh size equipped with NMC (811) cells.

High-nickel chemistries are more likely to be used in these third-generation designs. BAIC already uses NMC (532) in CATL's cell-to-pack design, giving pack-level energy densities equal to a second-generation pack using NMC (811). Concerns around safety and cycle life (due to changes to the thermal management systems and BMS) explain automakers' reluctance to integrate higher-nickel chemistries immediately.

The fourth generation of pack design was highlighted at Tesla's so-called Battery Day event. The company announced it would eventually adopt a cell-to-chassis design, though the timeline for this is not clear. Tesla suggested that the design could be in use as early as 2023, but BloombergNEF believes 2025 is a more realistic timeline. This design would drastically alter the pack-level costs. If the pack housing is considered part of the vehicle, the pack costs may only include the cells, BMS, thermal management system and connections. Tesla claimed that this approach and the accompanying changes to the cell design could cut the pack price by 56%.

Reference vehicles in each segment

Current and future reference vehicles in each segment in this report are based on prevailing technical characteristics in the European market in 2020 and recent trends. We use the vehicle weight as the main parameter that determines the vehicle's physical size and segment, and the power-to-vehicle-weight ratio as that which affects its performance. We define equivalent ICEs and BEVs as those that have a similar 'starting' weight and the same power-to-vehicle-weight ratio. For BEVs, we also set the real-world electric range and keep that constant for all years between 2020 and 2035 (Table 3).

The starting weight of the BEV is that of an ICE in the same segment, excluding the latter's drivetrain – ie, consisting mostly of the weight of the body and chassis, without the engine, transmission, fuel tank and some other components. On top of that, we add the weight of the battery, electric motor, (potentially) e-axles and other components. We then estimate the energy required to propel that mass and calculate the necessary battery capacity. We iterate this process in order to take into account the improving battery energy density and electric motor power density.

When designing a new BEV, automakers make a choice on the level of lightweighting by considering the costs of introducing new materials to reduce weight versus those of adding additional battery capacity to counteract heavier vehicles. The rapidly declining battery prices tip the balance in favor of the latter approach. Some lightweighting will nevertheless continue to be applied, but is more likely to be restricted to components, such as body panels, that may not serve structural purposes and could be shared between several vehicles.

We find that battery electric vehicles can be between 20-40% heavier than equivalent ICEs now (Table 3). The weight penalty declines rapidly, as the battery energy density improves around 50% between 2020 and 2030. By that time, BEVs tend to be up to 10% heavier, depending on the segment. The weight reduction resulting from more energy dense batteries is the major contributor to the efficiency improvements of BEVs by about 30% to 2030 (for more on battery technology improvements, see section 3.3). By that time, battery packs can weigh about a third less for the same capacity. For the same BEV range, batteries could weigh about half as much or less depending on starting vehicle weight. In 2020, we estimate that the energy density of battery packs was about 170 Wh/kg, which we expect to increase to around 250 Wh/kg by 2030.

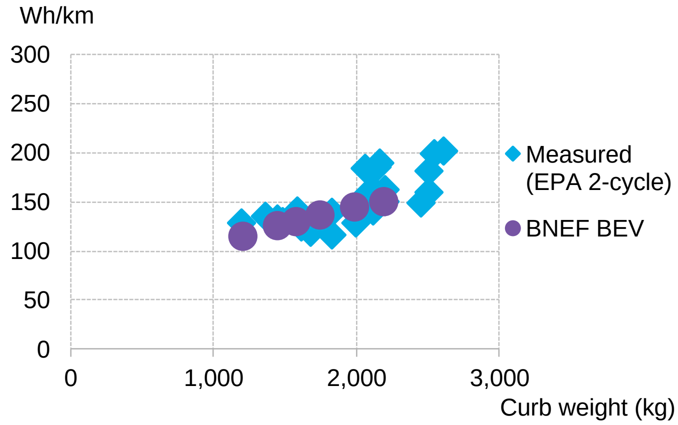
Table 3: Reference vehicle characteristics in 2020 and 2030

Segment	Type	Weight (kg)	Power (kW)	Electric real-world driving range (km)	Battery capacity in 2020 (kWh)	Efficiency (L/100km or Wh/km)	
						2020	2030
B	ICE	1,000	59	-	-	8.2	7.4
	BEV	1,200	70	300	57	171	121
C	ICE	1,200	84	-		9.9	8.4
	BEV	1,600	109	400	84	188	131
D	ICE	1,450	119	-	-	12.5	9.9
	BEV	2,000	164	500	113	203	142
SUV-B	ICE	1,250	67	-	-	9.2	8.1
	BEV	1,450	79	300	61	182	128
SUV-C	ICE	1,350	92	-	-	10.8	8.9
	BEV	1,750	118	400	87	195	135
SUV-D	ICE	1,650	128	-	-	14.0	10.6
	BEV	2,200	172	500	116	208	146
Light van	ICE	1,300	71	-	-	9.6	8.4
	BEV	1,500	84	300	62	185	131
Heavy van	ICE	1,900	100	-	-	15.1	12.7
	BEV	2,300	122	400	93	209	155

Source: BloombergNEF, MarkLines, EU Commission, ICCT, EPA. Note: the 2020 vehicle characteristics are the same for the baseline and optimized cases; figures are rounded. Efficiency is real world efficiency corresponding to the EPA cycle; BEV battery capacity declines 25-35% by 2030 under equal range.

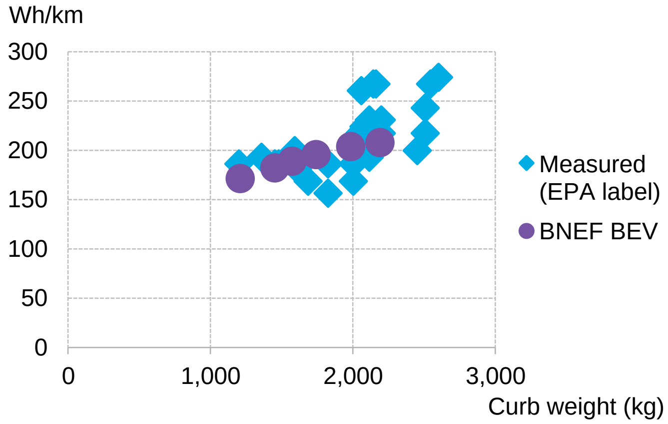
We compare the derived BEV efficiencies to those of the latest BEVs that have come into the market for both the testing cycle and real-world efficiencies (Figure 14 and Figure 15). Even though such comparisons depend on a number of factors, such as battery energy density, range, motor efficiencies, aerodynamics, and others, we find that our efficiency estimates fall within the range of real-world vehicles.

Figure 14: Cycle efficiency comparison between BEV available for sale and BNEF's reference vehicles



Source: EPA, BloombergNEF. Note: "measured" vehicles are those tested and certified for model year 2021 in the U.S.

Figure 15: Real-world efficiency comparison between BEV available for sale and BNEF's reference vehicles



Source: EPA, BloombergNEF. Note: "measured" vehicles are those tested and certified for model year 2021 in the U.S.

The driving range of electric vehicles

In this report, we assume that BEVs need between 300 and 500 km of real-world driving range. Such ranges are lower than the driving range of ICEs on a full tank. One of the main factors influencing the validity of this assumption is the expected deployment of public charging infrastructure. We explore that in the section on sensitivity.

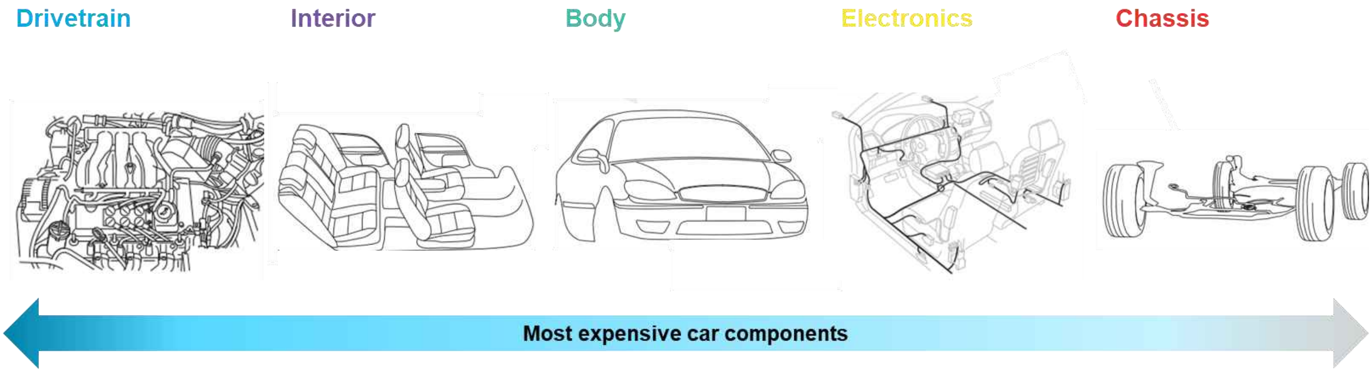
Between 2011 and 2019, the compound annual growth rate for the average range of BEV models launched globally was 13%, reaching just under 300 km (based on the EPA testing cycle; real-world driving range can be 20-30% less). New models in 2020 had an average range of 380 km, with some vehicles exceeding 600 km.

Despite that high growth, as well as promises of 1,000 km BEVs, we expect that range will not rise indefinitely. It is more likely that it will plateau later in the 2020s as charging networks improve. The market may eventually split, with lower-range smaller cars aimed at urban families with two vehicles, and larger, longer-range ones aimed more at single-car households.

Vehicle manufacturing cost breakdown

We estimate the costs of five vehicle systems (Figure 16) using a combination of methods, such as models for total costs, detailed manufacturing cost breakdowns, and individual component prices. With the addition of assembly costs, these comprise the total direct manufacturing cost of the vehicle (Figure 12).

Figure 16: Vehicle system costs by system and component



Drivetrain ~ 33%	Interior ~ 19%	Body ~ 18%	Electronics ~ 13%	Chassis ~ 13%
Engine ~ 20%	Seating ~ 8.5%	Body-in-white ~ 8.2%	HVAC ~ 2.9%	Suspension ~ 3.7%
Transmission ~ 8%	Dashboard ~ 5.7%	Paint ~ 2.9%	Interior ~ 2.5%	Steering system~3.2%
Fuel system ~ 2.3%	Trim ~ 2.5%	Body hardware ~ 2.0%	Drivetrain ~ 2.5%	Braking system~2.6%
Exhaust system~1.5%	Door modules ~ 1.9%	Closures ~ 1.5%	Chassis ~ 2.5%	Rims and tires ~2.0%
Cradle ~0.7%		Glazing ~ 1.6%	Exterior ~ 1.3%	Driveshaft/axle ~1.1%
Oil and grease ~0.5%		Exterior trim ~ 0.9%	Engine thermal ~ 1%	Differential ~ 0.8%
		Bumpers ~ 0.8%	Energy storage ~0.5%	
		Sealers ~ 0.2%	Emission control~0.3%	

Major cost · High cost · Some cost · Minor cost

Source: BloombergNEF, ORNL, INL, ANL, McKinsey. Note: refers to C segment vehicle.

For internal combustion engines and transmissions (which can account for more than a quarter of the ICE direct manufacturing cost, Figure 16), and for electric motors we use cost models that mostly depend on the vehicle's power output. Such models naturally adapt to vehicle sizes, based on their different technical characteristics. For batteries, we use the same price for all segments and power outputs.

Beyond the drivetrain, the main differences between ICEs and BEVs are found on the chassis and electronics (Figure 17). Suspensions, steering and braking systems, and axles can be more complex and 5-15% more expensive for a BEV, especially one built on a non-dedicated platform. The additional weight of electric cars, as well as the potential integration of motors or other items on the axles, determine the cost of such components. However, the magnitude of some of those effects declines as electric vehicles become lighter.

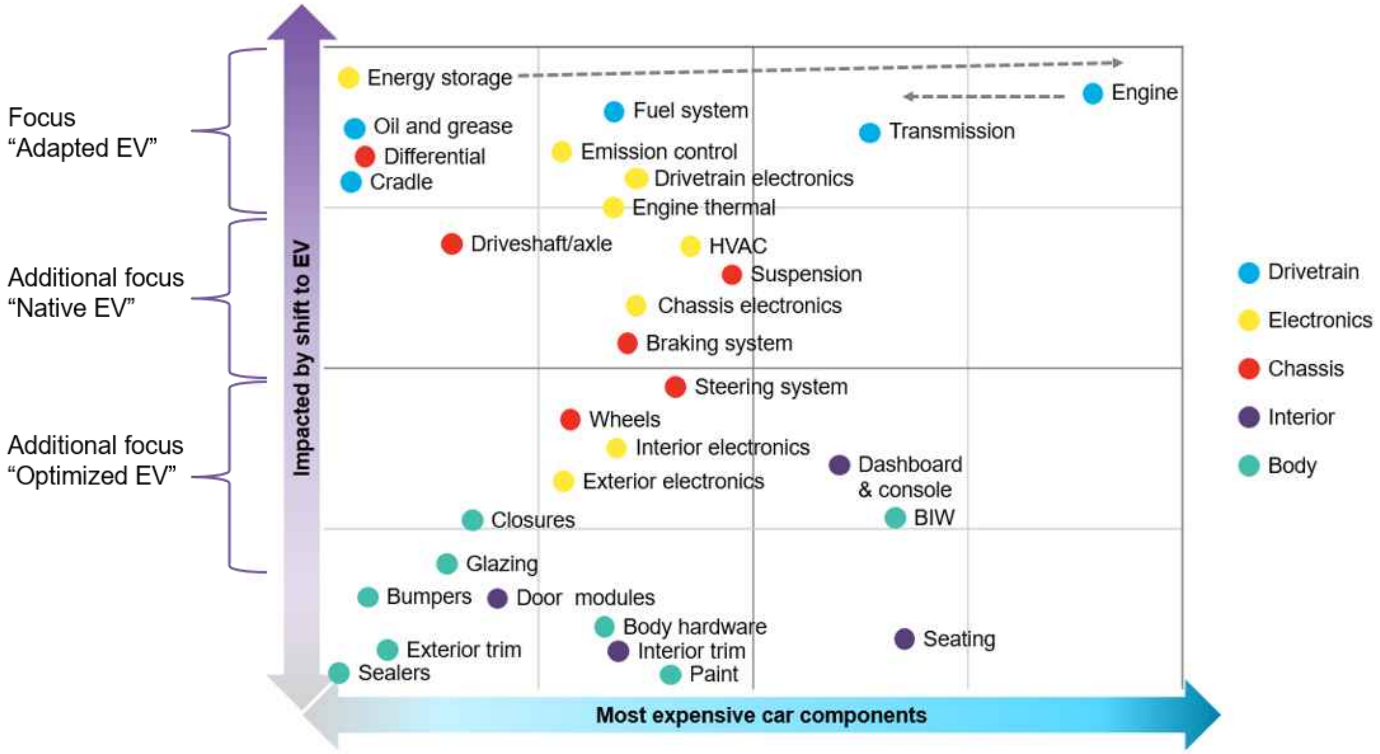
On the electronics side, the high electrical power of BEVs and the lack of the thermal output of the combustion engine affect the cost differential of control electronics, and heating and ventilation systems[2] (HVAC). The BEV-to-ICE cost difference can be between 50-100% for the whole electronics system, in particular with the currently low manufacturing volumes and still-emerging supply chain. However, scale effects could push lower the costs of many of those components by 2030, even though HVAC systems may still command a small premium.

[2] We take into account the additional battery capacity that may be required for heating and air-conditioning when estimating the total energy requirements of BEVs.

The manufacturing methods and cost structure of vehicle bodies are likely to remain similar between the ICEs and BEVs. We use the detailed direct manufacturing cost breakdown of the body of an average vehicle[3], which we then scale to other required sizes and materials choices. We adjust for some differences in complexity between the two powertrain technologies, such as the non-existent engine bay structure in BEVs, but these tend to have a low impact.

In the interiors, some components – such as seats – may be more complex for BEVs, but others, such as dashboards, may be simpler[4]. On balance, we expect that interior costs will be almost the same between ICEs and BEVs. We estimate those using individual component costs from a baseline vehicle, some of which may vary slightly between segments following differences in the vehicles' physical dimensions. We assume no change of those costs over time.

Figure 17: Focus areas for shift to EV



Source: BloombergNEF, expert interviews.

From manufacturing costs to the market prices of vehicles

The estimated direct manufacturing costs are between 50-70% of the total costs of developing, producing and selling a vehicle (Figure 18, corresponding to a medium size sedan). The additional costs comprise production and corporate overheads, such as R&D and management, selling, marketing and distribution costs, as well as the cost of managing and maintaining a dealer network. Lastly, a profit margin should be added to arrive at a vehicle's pre-tax retail price. For the

3 Into material, labor, directly attributable production overhead, maintenance and energy costs.

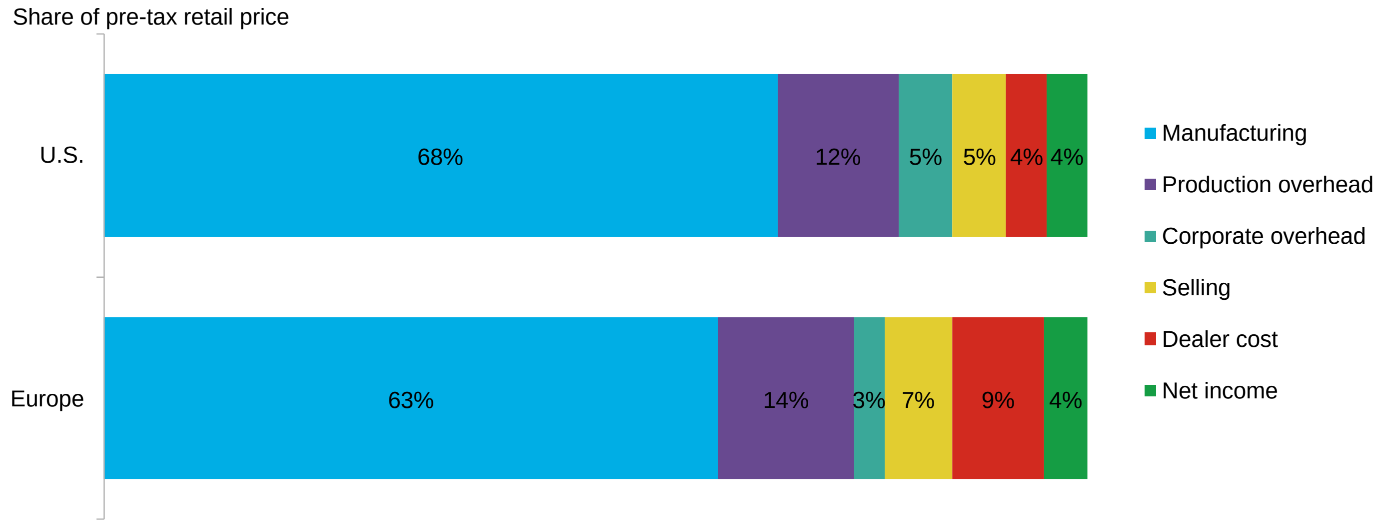
4 While there are no inherent reasons for that, some automakers have expressed the opinion that BEVs offer opportunities for simplification of some parts of the interior. That is due to the mere fact that BEVs can be marketed afresh and do away with components and design choices that are considered established in current vehicles.

analysis, we assume that the required profit margin for ICEs and BEVs is the same. We believe that this is a necessary condition for automakers, as they attempt to maintain the overall profitability of their businesses. Some manufacturers have stated that they expect to reach such 'profit parity' in the next few of years, whereas others may cross-subsidize their EVs using higher margins in ICE vehicles until battery prices fall further.

The allocation of these indirect costs to particular vehicle models is not straightforward and potentially is a strategic as well as an accounting choice for an automaker. For ICEs, we estimate these additional costs as a markup on the direct manufacturing costs; the markup factors range from 1.6 to 2.0, depending on vehicle segment. We estimate that based on different cost structures between automakers as evidenced in their annual accounts[5] and comparing with market prices.

Following the same approach for BEVs means that these costs are directly affected by battery manufacturing costs. However, we believe it is unlikely that many of those expenses, such as R&D or marketing, would either be as large now or drop as fast in the future as current and future battery costs may imply. So, we use the costs estimated for ICEs as a basis and we adjust them mostly for different expected production volumes. The resulting markup factors range from 1.6 to 2.1 for BEVs built on modified platforms, and between 1.5 and 2.0 for those built on dedicated platforms.

Figure 18: Vehicle retail price breakdown



Source: EPA, FEV, BloombergNEF Note: refers to a medium-size passenger car

3.3. Battery pricing and outlook

Prices today

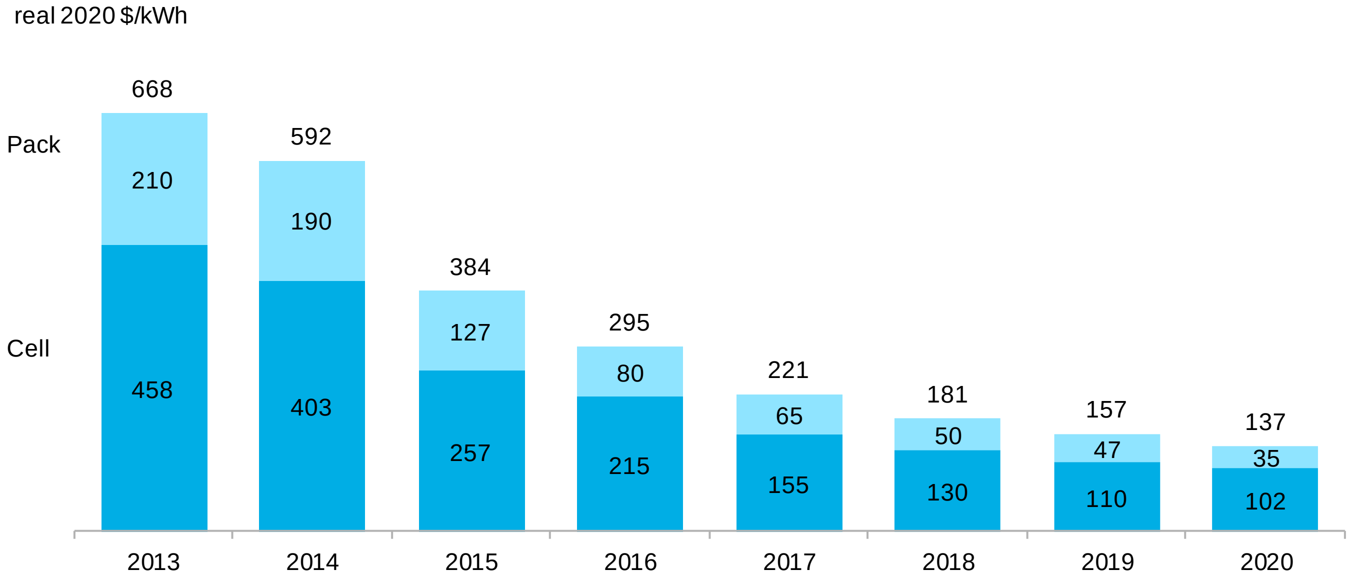
Falling prices for lithium-ion batteries are the biggest technology driver supporting the rapid rise in EV sales. BloombergNEF's 2020 volume-weighted average lithium-ion battery pack price was

[5] Using automakers' quarterly and annual accounts it may possible – in some cases – to also back-calculate aspects of the cost structure for groups of popular model lines. This is of course not entirely precise and we use it as a check of the direction and magnitude of differences in the markup factors.

$137/kWh, a fall of 13% in real terms since 2019. In EVs, the pack consists of cells, module housing, the battery management system (BMS), wiring, pack housing and thermal management system. Average lithium-ion battery pack prices are now down 89% from 2010.

Battery cell prices are already approaching $100/kWh. In 2020, the pack-to-cell split for across all battery segments was 74:26 (Figure 19). This marks a change from previous years when the split has been closer to 70:30. The split varies significantly between use cases. In e-buses and commercial EVs in China the split is closer to 85:15, whereas in plug-in hybrid electric vehicles (PHEVs) the split is closer to 45:55. The differences come from the variations in pack design and requirements.

Figure 19: Pack and cell split, all sectors



Source: BloombergNEF 2020 Lithium-ion Battery Price Survey

For the past decade, the battery pack has been the single most expensive part of an electric vehicle (EV). In 2016, the pack accounted for almost 50% of a medium-sized battery electric vehicle (BEV) in the U.S. It is now closer to 30% and will continue to fall. There is still a wide range of lithium-ion battery pack prices in the market. High-volume BEVs typically have lower average battery pack prices per kWh than plug-in hybrids or commercial vehicles.

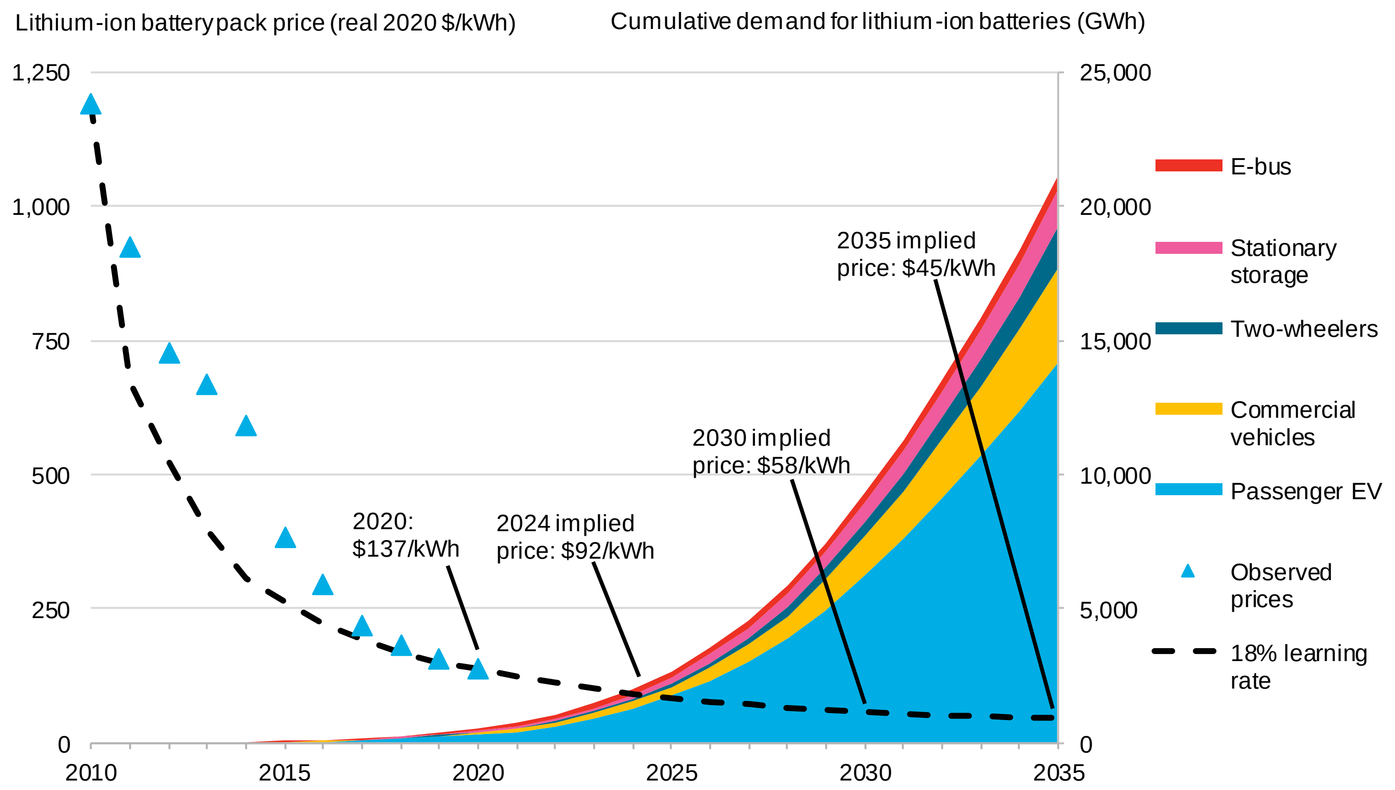
In 2020, the cheapest European batteries were competitive with some of the lowest prices globally, but prices in Europe were more widely spread. This means the average price for battery packs in Europe was higher than the global average, partially resulting from some lower volume orders. As sales expectations and manufacturing strategies differ between automakers, we expect such price differences to persist for a few more years. Our cost estimates take that difference into account, whereby modified BEVs incur higher battery costs compared to those built on dedicated platforms (for which we use the battery prices in Figure 20). We expect manufacturers to gradually adopt dedicated platforms, and our vehicle cost declines also reflect this switch to cheaper batteries by 2025.

Battery price outlook

Demand for lithium-ion batteries used in EVs and stationary storage has grown more than 264 times from 2010 to 2020. BloombergNEF has collected pricing and volume data for lithium-ion battery packs since 2010. Based on an 18% learning rate, BloombergNEF expects lithium-ion battery pack prices will fall below $100/kWh in 2024 and reach $58/kWh in 2030 (Figure 20).

By 2035, BloombergNEF projects that lithium-ion battery packs could achieve a volume-weighted average price of $45/kWh. For an EV with a 100kWh battery pack, the pack price would be $9,200 cheaper in 2035, a fall of 67% from 2020. It is not yet clear from a bottom-up perspective how the industry can achieve these prices. It may well require material substitution and will certainly require further technology advancements. It is equally hard to understand the full implications of this low pricing, which could unlock new demand sectors that are currently not addressable, and improve economics (and subsequent uptake) in sectors that have already started to electrify.

Figure 20: Lithium-ion battery pack price and demand outlook



Source: BloombergNEF 2020 Electric Vehicle Outlook and 2020 Lithium-ion Battery Price Survey.

Despite these implied low pack prices, the annual rate of price declines is slowing. This is consistent with the concept of a learning rate, which links the rate of price declines to the cumulative volume of battery packs deployed on the market. The observed 18% learning rate indicates that every time the cumulative volume of batteries deployed on the market doubles, pack prices fall by 18%. As the market expands, more time elapses between each doubling of cumulative battery capacity. In the five-year period between 2020 and 2025, cumulative volumes are expected to double twice (Figure 20). A decade later, in the five years between 2030 and 2035, volumes only double once.

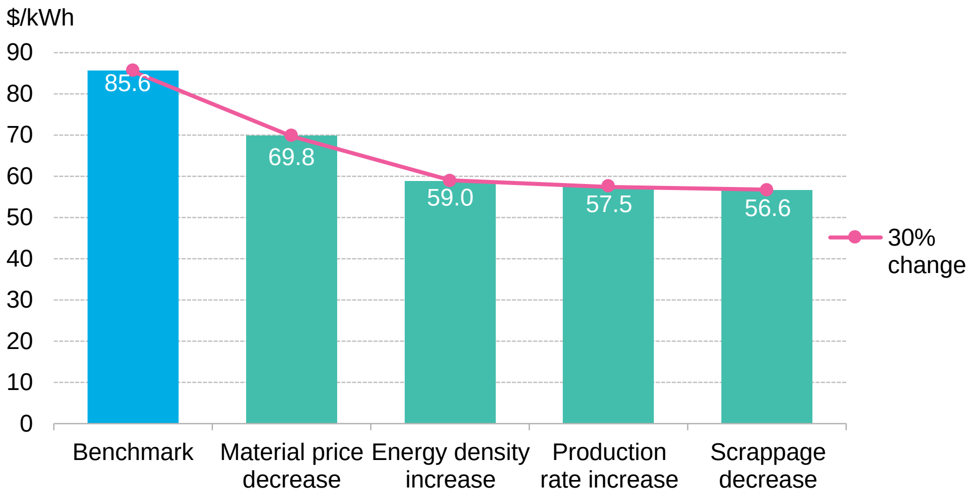
Price outlook: 2021-2025

The cost reductions that can be achieved over the next five years are already well understood. In the automotive industry, cells have already been procured, with prices set, for most vehicles being launched over this period. Outside of passenger EVs many companies still procure cells closer to when they are required.

The biggest uncertainty for most automakers will be the cost of raw materials (see the section on sensitivity below). Automakers may be forced to quickly pivot to different chemistries or suppliers if key raw materials like cobalt or nickel are in short supply. This would affect pack pricing as well.

Using BNEF's Bottom-Up Battery Cost Model, we outline one route cell manufacturers can take to reduce manufactured cell costs to the point that they enable pack prices of less than $100/kWh (a benchmark we expect by 2024). A 30% improvement in four key areas would reduce the manufactured cost of a cell by 33%, to $61/kWh (Figure 21). The four areas are: decrease in material costs, increase in energy density, increase in output and decrease in scrappage rate. The cost trajectory in Figure 21 is a scenario, whose individual steps are already technically feasible in isolation albeit harder to achieve simultaneously. Still, the resulting price should not be viewed as a floor below which battery costs cannot pass. Material prices can also fall by changing things like the chemistry composition, for example substituting cobalt for nickel or nickel for manganese.

Figure 21: Potential battery-cell cost reductions



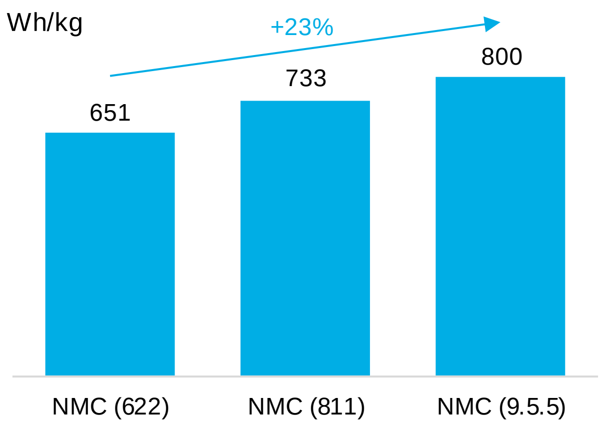
Source: BloombergNEF. Note: Using the manufacturing cost of NMC (622) prismatic cell in 2019 as benchmark. The material price decrease calculation only includes the prices of four major components - cathode active material, anode active material, electrolyte and separator. Energy density refers to cathode active material energy density, instead of battery energy density; the figure shows a scenario of possible cost reductions, assuming a 30% change for each of the four steps given as labels.

Additional costs such as SG&A (selling, general and administrative expense) and the manufacturer's margin would give a final cell price of around $70/kWh. Assuming the pack-to-cell price ratio of 74:26 in 2020 gives a final pack price of $94/kWh. This is in line with our expectation for average pack prices in 2024.

Cell chemistry improvements

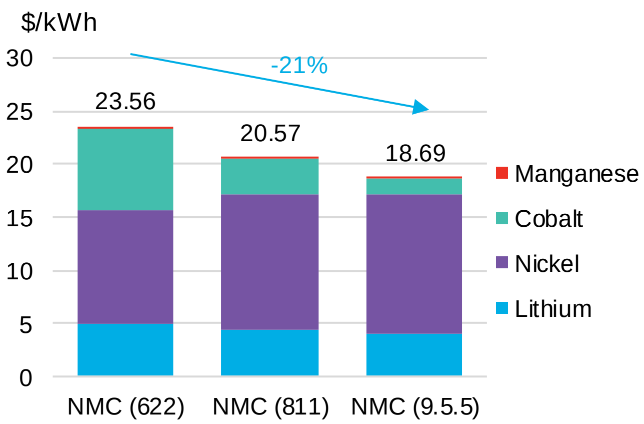
The adoption of new cathode materials alone can almost realize these savings. Moving from the commonly used NMC (622) cathode material to NMC (9.5.5), which SK Innovation will use in commercial cells from 2022, would result in a 23% increase in energy density and a 21% decrease in raw material costs (Figure 22 and Figure 23).

Figure 22: Energy density by chemistry



Source: BloombergNEF. Note: NMC (9.5.5)'s energy density is estimated.

Figure 23: Raw material costs by chemistry



Source: BloombergNEF. Note: Based on commodity prices as of November 30, 2020. Does not include processing costs or losses from production.

Cell manufacturing improvements

Improvements to production and scrap rates are likely to outstrip the 30% improvements shown in Figure 21. Over the past three years, average scrap rates have fallen from around 7.5% to 5%, a reduction of 33%, a trend that we expect will continue.

Production rates for cell lines are also increasing dramatically. The unit production rate of cylindrical lines increased 150% between 2010 and 2020. If improvements continue at this rate production speeds may be 75% higher by 2025. The output of cell lines in GWh can also increase through the adoption of new cell designs that pack in more kWh per cell. Cell formats have become increasingly standardized in recent years. This is increasingly important for large automakers, which may need to procure from different suppliers in different regions.

Battery manufacturing capex

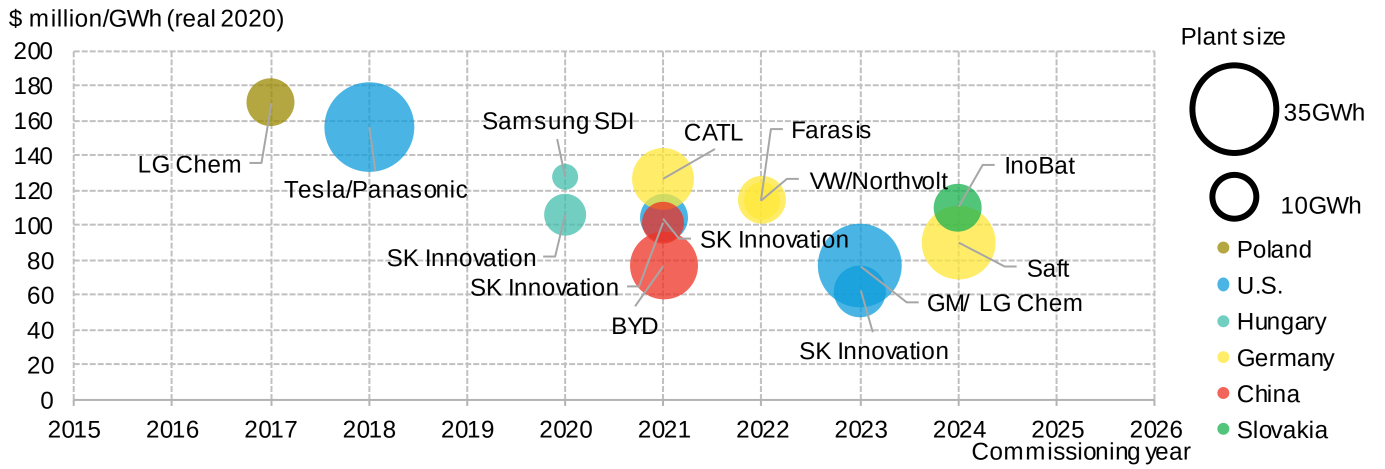
BloombergNEF's benchmark capex cost for a new-build battery manufacturing plant is around $110 million/GWh. Since 2017, capex costs have fallen 34% and are set to fall another 28% by 2023 (Figure 24).

Reducing capex is an important way to lower cell costs. Capex savings for new-build plants will come from a number of different areas:

- **Chemistry changes:** Plants can produce a set number of cells each year. Producing higher energy density cells increases the kWh contained in each cell, lowering the $/GWh capex.

- **Power versus energy:** PHEVs use cells that are geared toward power, while BEVs use energy cells. As the ratio of PHEVs to BEVs sold in the market shifts in favor of the latter, manufacturers will produce more energy cells. Energy cells have more kWh than power cells, which means this industry trend will increase the GWh produced at factories, thereby reducing the $/GWh capex.
- **Manufacturing equipment:** Companies continue to improve the factory efficiency and utilization. This results in capex and opex savings as well as higher output volumes. CATL and LG Chem both highlighted the role increased utilization played in increasing margins and reducing cell costs in their 1Q 2020 reports.
- **Subsidies:** These have played a key role in attracting battery manufacturing to certain regions.
- **Greenfield versus brownfield:** It can be cheaper to expand existing sites than open up new ones. This is because much of the infrastructure is already in place and the land already owned or leased. The scale of new manufacturing plants required by 2030 will limit how many brownfield sites can be expanded.
- **Location:** The location of a new plant impacts the capex required. Building a factory in Poland is less capital intensive than building in other parts of Europe (Figure 24). There are, of course, other considerations that should be taken into account, such as the grid emissions of the country and the availability of a skilled workforce.

Figure 24: Greenfield battery manufacturing capex



Source: BNEF, public reports. Note: it is not always clear if a facility will manufacture cells, or cells and packs.

Price Outlook 2025-2030

There are many possible pathways to realizing the price declines expected during the second half of this decade. This could be through the adoption of new system designs, such as solid-state cells, or improvements to existing liquid-based systems. There is tremendous overlap between these pathways. Improvements under development for liquid-based systems, such as dry electrode coating, could equally be adapted for solid-state cells.

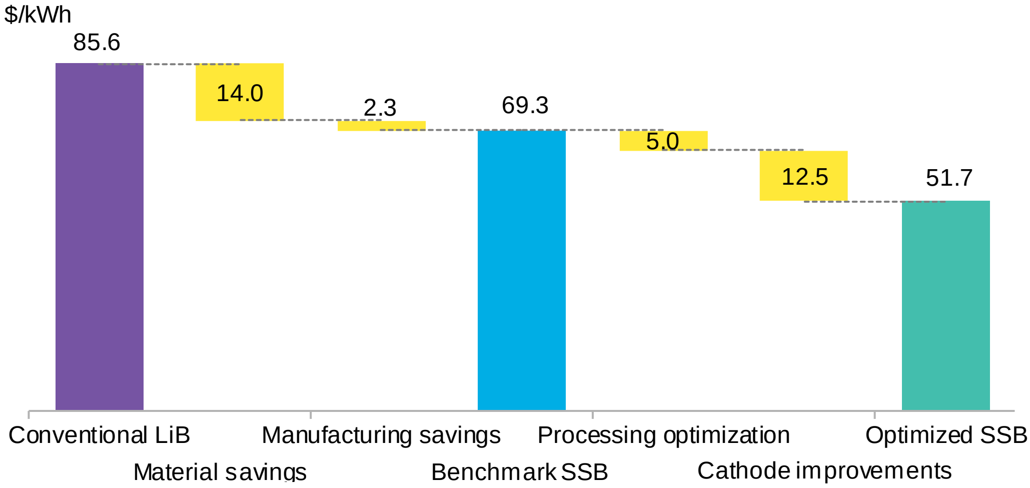
Solid-state

Solid-state cells could be manufactured for $52/kWh

Solid-state cells are likely to be more expensive than cells using liquid-based electrolytes when initially introduced. Nonetheless, their costs could fall quickly. Manufacturing costs could fall since the technology obviates the need for certain processes like formation or aging. The technology also enables the adoption of new cathode and anode materials that may not be compatible with the existing generation of liquid electrolytes.

BloombergNEF estimates that an optimized solid-state cell using next-generation cathode materials and 15µm thin lithium foil anode could be manufactured for a cost of $52/kWh (Figure 25). BloombergNEF currently expects that supply chains and technology could be sufficient to enable this by around 2030.

Figure 25: Solid-state battery (SSB) cell manufacturing cost reduction outlook, 2030



Source: BloombergNEF. Note: Conventional LiB is based on a 60Ah NMC (622) pouch cell. SSB refers to the solid-state battery with lithium metal anode. Material savings include reduced material costs for both active and inactive components as well as the increased cost for the electrolyte. Manufacturing savings include saved costs across labor, manufacturing as well as equipment and plant depreciations

This would still be around $5-10/kWh too high to realize our 2030 pack price of $58/kWh. Improvements to manufacturing, like cell line speed and dry electrode coating, could, however, further reduce the manufactured cost and make this target achievable.

Solid-state batteries are not the only route to further cost reductions. There are various innovative approaches that could help liquid electrolytes maintain their dominance of the lithium-ion battery market, including improved cell designs and new electrolytes.

Liquid electrolyte

Lithium-ion batteries have used liquid-based electrolytes for the past 30 years. Various innovative approaches could help this technology maintain its market dominance.

Improved cell design

Cylindrical cells are the cheapest to produce on a unit basis, but they have in the past faced limits on their maximum size. The larger they are, in diameter and height, the harder it is to control their internal thermal behavior, which hinders performance. This can give pouch and prismatic cells, that are produced at a slower unit rate but contain more kWh, an advantage over their cylindrical counterparts. At its 'Battery Day' event, Tesla unveiled a new tab-less cylindrical cell design, which enables it to overcome some of the size limitations of cylindrical cells. Using this approach, it expects that with the current generation of liquid electrolytes, it can further reduce cylindrical cell costs. BloombergNEF estimates that its manufactured cell cost would be close to $50/kWh. In contrast to Tesla, VW has chosen a prismatic cell format for use in 80% of its vehicles by 2030.

New electrolytes

Innolith, a startup headquartered in Switzerland, has developed a novel inorganic liquid electrolyte. Unlike the organic electrolytes used today, it can be used in combination with next generation high-energy density, high-voltage cathodes. These new materials promise to both increase energy density, which reduces manufacturing costs, and reduce material costs.

Cathode material production

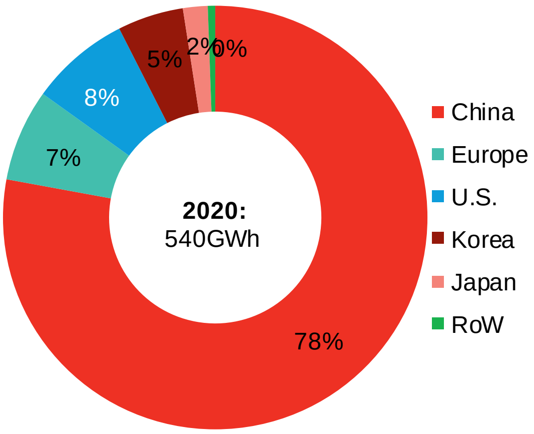
Cathode materials account for an increasing proportion of cell and pack costs. We expect the cathode will account for 43% of the pack price, an increase from 31% today, on a volume-weighted basis. Multiple companies are working on innovative approaches to reduce the cost of producing raw materials, precursors and cathodes.

Increased competition

Some 21% of commissioned manufacturing capacity will be in Europe by 2025

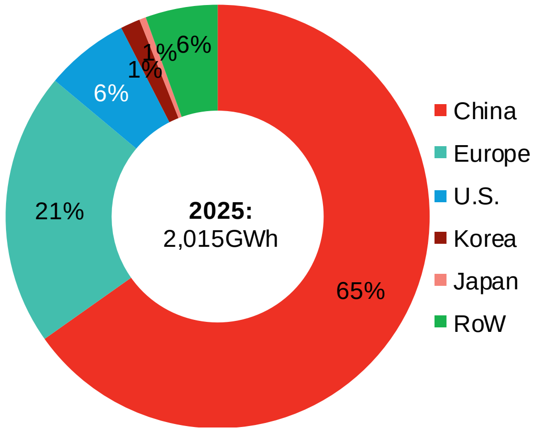
Various new cell manufacturers, such as Northvolt, Freyr and Automotive Cell Company (ACC), are all vying for a share of the growing market. These new manufacturers, alongside the expansion of existing companies, will help Europe grow its share of installed capacity from 7% to 21% (Figure 26 and Figure 27). As these new manufacturers start volume production, there could be increased pressure on companies' pricing strategies as they attempt to increase or maintain market share. Margins may well be sacrificed along the way.

Figure 26: Global manufacturing capacity, 2020



Source: BloombergNEF

Figure 27: Global manufacturing capacity, 2025



Source: BloombergNEF

Price Outlook: 2030-2035

How the industry achieves costs reductions beyond 2030 is unclear as we are only just beginning to quantify how manufacturing, materials, cell and pack designs will change over the next decade.

It is fair to say that continued improvements across all these areas will remain important in realizing these prices well into the next decade.

3.4. Vehicle cost results

Main outputs

The estimated pre-tax retail prices of battery electric vehicles are set to decline rapidly by 2030, as average battery prices fall by close to 60%. However, the vehicle price decline between 2020 and 2030 is steeper than this. BEVs in the early 2020s will mostly be built on non-dedicated platforms with relatively low production volumes. The switch to dedicated platforms by the mid-2020s implies that production volume-related BEV cost penalties are set to disappear (Figure 28 and Figure 29 show the price curves for all segments in Appendix A).

The cost difference between average BEVs and equivalent ICEs varies widely by segment. Light and heavy battery electric vans are for now about 50% more expensive, as they have modest performance requirements and medium ranges. In contrast, smaller battery vehicles in segments A and B can cost more than twice as much compared to ICEs. Powertrain costs in these segments tend to be low compared to total manufacturing costs at the moment, due to wide use of smaller and cheaper gasoline engines. Even low-capacity batteries – around 55 kWh for B-segment BEVs – may cost more than three times the total ICE drivetrain today.

Figure 28: Estimated pre-tax retail prices for C segment vehicles

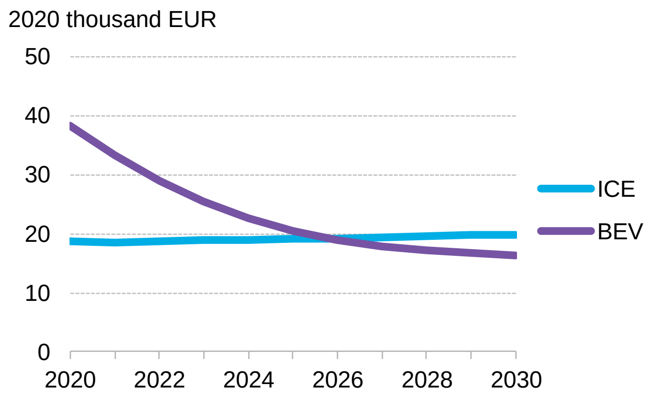
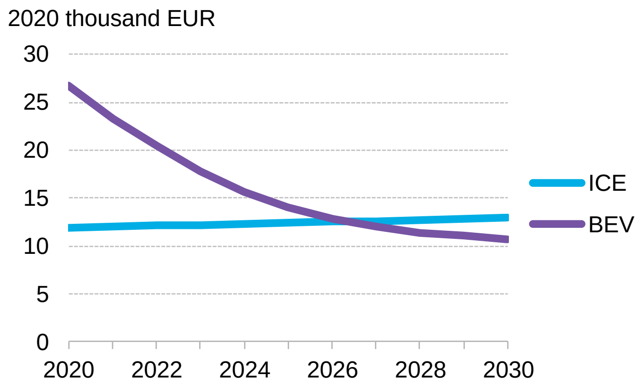


Figure 29: Estimated pre-tax retail prices for B segment vehicles



Source: BloombergNEF Note: ICE is internal combustion engine vehicle and BEV is battery electric vehicle

Figure 30: Estimated pre-tax retail prices for SUV-C segment vehicles

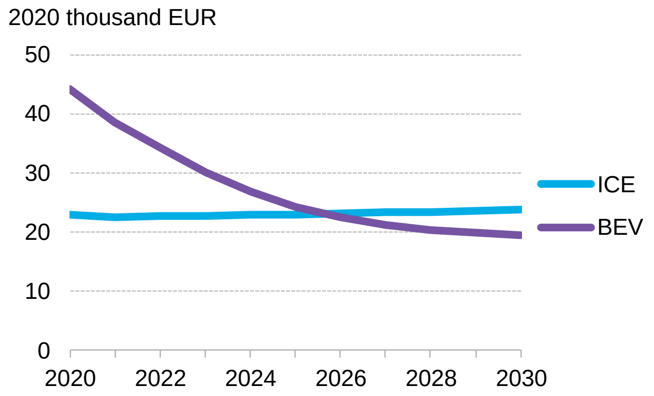
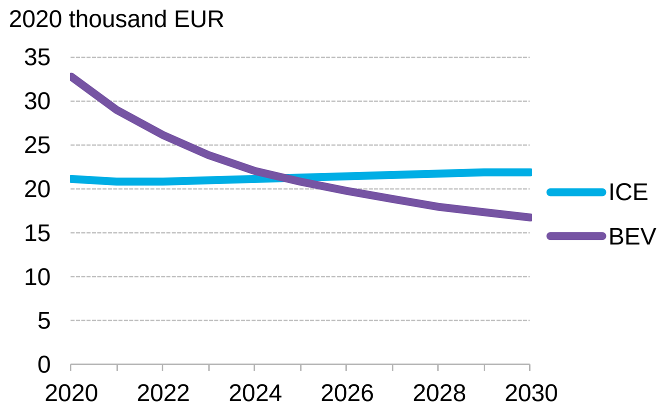


Figure 31: Estimated pre-tax retail prices for light vans



Source: BloombergNEF Note: ICE is internal combustion engine vehicle and BEV is battery electric vehicle

The BEV-to-ICE price difference gets increasingly small over the next five-to-six years in all segments. Battery electric vehicles reach the same price as equivalent ICEs within a tight window between 2025 and 2027 (Table 4). Vans reach price parity the earliest, B segment vehicles are the latest, while larger sedans and SUVs are in between. This ranking of price-parity years depends mostly on the vehicles' technical characteristics – primarily, their assumed range – and not directly on their average purchase price.

Table 4: Years at which BEVs reach upfront cost price parity with equivalent ICEs

Segment	Year	Segment	Year	Segment	Year
B	2027	SUV-B	2026	Light vans	2025
C	2026	SUV-C	2026	Heavy vans	2026
D	2026	SUV-D	2026		

Source: BloombergNEF. Note: we define price parity as the year at which a BEV becomes cheaper than the equivalent ICE.

Vehicle cost structure

In this section we show in more detail the direct manufacturing costs of ICEs and BEVs (Figure 32 and Figure 33).

Some modest cost declines for the body and chassis of ICE vehicles are quickly outweighed by the rising expense of improving the combustion engine. The 2025 and 2030 tailpipe CO_2 emissions regulations and the Euro 7 emissions standards – which are being planned and set to come into effect by 2025 – pose serious challenges for the cost-effective development of new combustion drivetrains. The need for elaborate injection equipment and turbochargers, as well as more complex exhaust systems mean that within the 2020s combustion engine costs will rise between 1% and 2.5% annually. Cost increases will be higher for smaller segments, as gasoline engines are also closing the efficiency gap with diesel powertrains.

The direct manufacturing costs of BEVs drop by at least 50% by 2030, depending on the segment, and more than three-quarters of that is due to the battery. Additional cost declines are a result of more power-dense electric motors and cheaper electronics.

Figure 32: Direct manufacturing costs for ICEs and BEVs, C segment vehicle

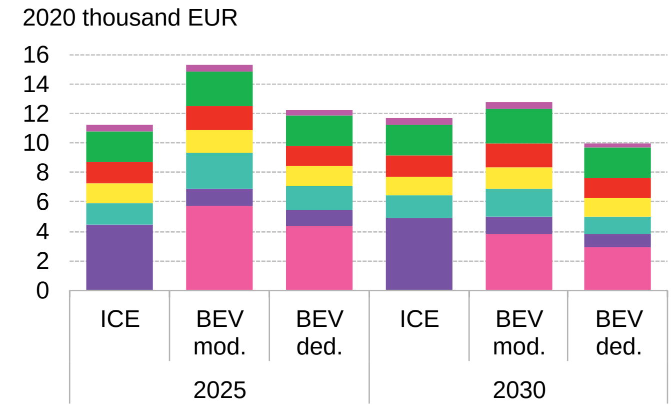
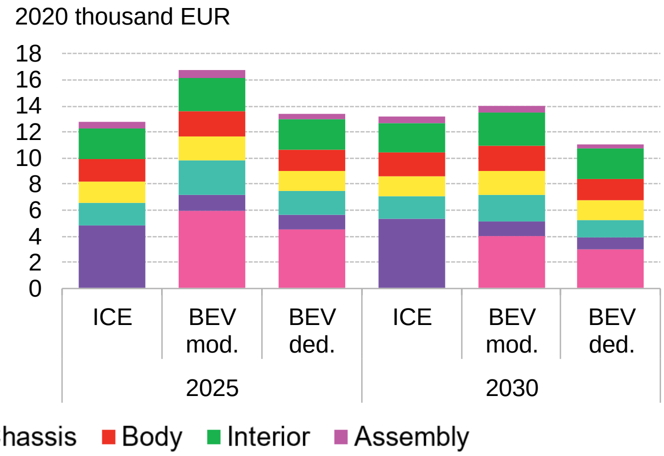


Figure 33: Direct manufacturing costs for ICEs and BEVs, SUV-C segment vehicle



Source: BloombergNEF. Note: "BEV mod." refers to the conservative pricing scenario using a modified platform and "BEV ded." to a BEV built on a dedicated platform; the drivetrain of the ICE includes the engine, transmission, etc, whereas for the BEV it includes the electric motor, its transmission and electronics; ICE is internal combustion engine vehicle and BEV is battery electric vehicle

Sensitivity analysis

The pre-tax retail prices for battery electric vehicles derived above depend on four main parameters: platform choice, battery price, driving range and vehicle efficiency. Changing these inputs (as in Table 5) provides an estimate of vehicle-price sensitivity within a wide range of the assumptions that underlie vehicle prices.

Changes in the input parameters are not mutually exclusive, though not every combination is equally likely. For example, in a lower-than-expected battery price environment, automakers may well choose to increase, rather than decrease, the driving range of their vehicles. There are several reasons for potential variations in input assumptions including consumer behavior, local and national policies, as well as companies' and countries' industrial strategies.

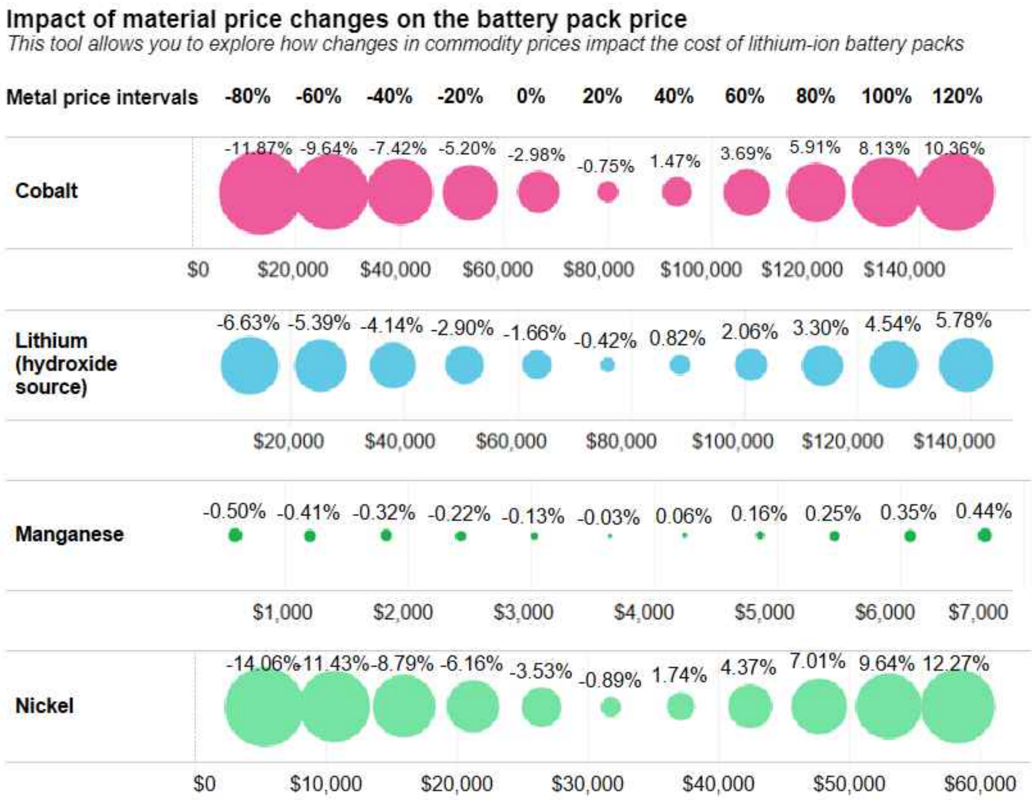
Table 5: Battery electric vehicle price sensitivity parameters

Parameter	Low value	High value
Platform	Dedicated	Modified
Battery price	-15% in 2030 vs BNEF central battery price forecast	+75% in 2030 vs BNEF central battery price forecast
Driving range	-50% vs central scenario	+50% vs central scenario
Vehicle efficiency	+12% vs central scenario	-12% vs central scenario

Source: BloombergNEF. Note: the "low" and "high" values for the platform are qualitative, rather than quantitative, labels; the driving range and efficiency depend on vehicle segment (Table 3).

For batteries, in particular, volatile input material costs pose a considerable uncertainty for their price outlook. In the last few years, the direction of raw material prices was supportive to battery cost declines. However, prices for some of those materials have been edging upward recently, while they have experienced sizeable price swings in the past. Nickel and cobalt prices have the largest effect on the cost of an NMC (622) pack. A doubling of prices of these (from around $26,000/metric ton and $65,000/metric ton, respectively, in February 2021) would increase battery costs by about 9.5% and 8.1%. If material prices reduce by 40%, then the battery pack cost would also drop by 8.8% and 7.4%. The change in the final price of a battery pack is a lot lower than that of input material costs. Even if cobalt, lithium and nickel prices double (compared to Feb 2021 prices), then battery pack prices would only increase by less than 25%. The high end of our battery prices in the sensitivity analysis here is likely to result not from higher material prices alone, but also from a combination of several factors, such as low production volumes, slow technology improvements and other factors.

Figure 34: Impact of material price changes on pack price of a NMC (622) battery



Source: BloombergNEF. Note: Bubble size represents the change in the price of a battery pack corresponding to the change in the price of one of the materials in the cathode; input material prices are from February 2021

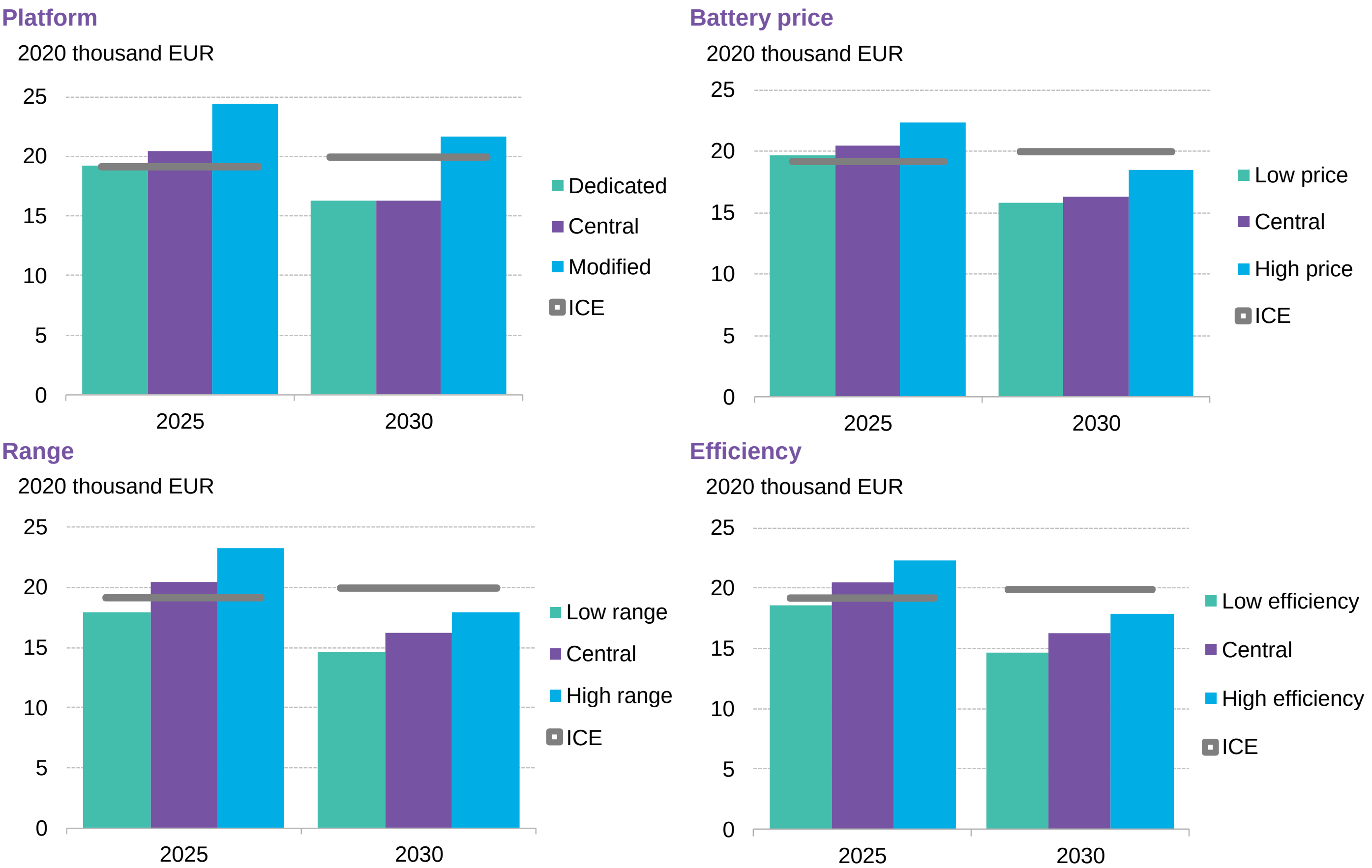
With the changes in Table 5, the pre-tax retail prices of BEVs can range from 16% lower to about a third higher compared to our central scenario. The choice of platform strategy – which encompasses the combined effects of production volume, efficient vehicle design and optimized cost structure – is crucial, as by 2030 BEVs built on dedicated platforms may cost about a quarter less to produce versus those that may still use modified ones (Figure 35).

On the individual parameters, the choice of driving range can materially change a BEV's affordability. A 50% change in the driving range of a BEV in the C segment, results in about 25%

difference in the price of the car in 2025 compared to the central case[6]. The effect of the battery price change alone is lower, at around 17% by 2025. Finally, good old engineering design should not be underestimated. Increasing a BEV's efficiency by about 10% can result in a similar magnitude improvement in costs versus the central case, as a result of fewer losses and lower vehicle weight, hence smaller battery and electric motor requirements.

The price parity years could shift by up to two years as a result of the changes in Figure 35 and range between 2025 and 2028 for the C segment vehicle, compared to 2026 for the central scenario. The biggest effect is from the battery cost, either through the $/kWh pack price or the vehicle's driving range. In the unfavorable cases of Table 5, price parity is delayed by two years, whereas it can come one year earlier with low battery prices or shorter driving ranges. Due to the performance and price advantages, we expect manufacturers not to stay behind on dedicated platform development by the latter half of the 2020s, outside some niche applications. We acknowledge that the share of the market that could make use of dedicated platforms by 2025 could be lower than three quarters. In a less optimistic scenario where the market delays, and only about half of vehicles are built on dedicated platforms, this would move the average parity year from 2026 to 2027. Automakers who move earlier could have an advantage over those who chose to stay on older platforms.

Figure 35: BEV price sensitivity for a C segment vehicle



Source: BloombergNEF Note: the scenario inputs are in Table 5 and more details on the central scenario in Section 3.2

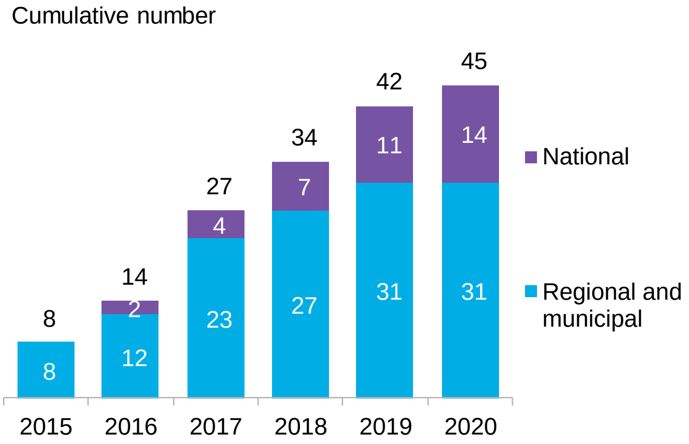
[6] For C segment vehicles, the central case is 400 km of real-world driving range, so this change results in BEVs with either 200 or 600 km of range.

Section 4. Phasing Out Internal Combustion Vehicle Sales in the European Union

4.1. Background and context

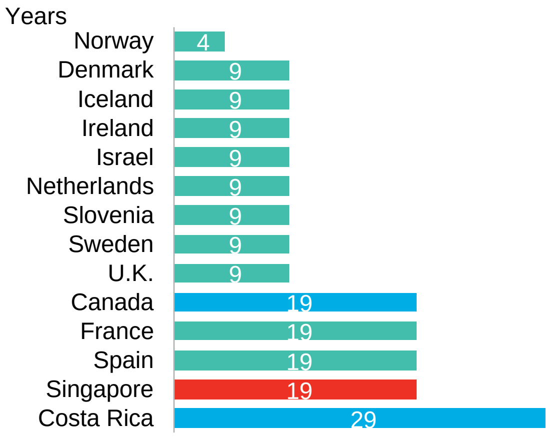
The number of countries planning to phase out sales of internal combustion engine vehicles (ICE) continues to increase. Fourteen countries have now expressed long-term policy goals of phasing out sales of ICE vehicles. Together, the national targets represented 11% of global new passenger car sales in 2019. Additionally, 31 regional and municipal governments around the world announced their intentions to phase out ICE vehicle sales (Figure 36).

Figure 36: Number of national, regional and municipal governments announcing plans to phase out sales of combustion vehicles



Source: BloombergNEF

Figure 37: Years remaining until ICE sales phase-out targets in select countries



Source: BloombergNEF. Note: U.K. target includes PHEV sales until 2035.

European countries represent ten out of the fourteen national ICE phase-out ambition announcements globally, and are among the countries with the most aggressive targeted dates (Figure 37). However, such targets globally remain vague on many aspects – around the inclusion of hybrid and plug-in hybrid vehicles and potential penalties for missing the target. There are also questions on the enforceability of national phase-outs within EU member states. Due to these uncertainties, the targets are not assumed to be hit in this outlook and are not included in our short-term and long-term EV-adoption forecast discussed below.

With only nine years left for reaching many of the targets (four in the case of Norway and 19 for France and Spain), most of the European countries with ICE phase-out plans are still some way from reaching them. At the end of 2020, Norway was on broadly on track for its 2025 target, while Iceland was half way toward the target set for 2030, with EV adoption in Sweden, the Netherlands and Denmark at 32%, 25% and 16%, respectively. The progress toward ICE phase-out targets in larger European car markets, like France or the U.K., is further behind, with the EV share of passenger car sales just exceeding 10% at the end of 2020 in both countries (Figure 38 and Figure 39).

Figure 38: 2020 Europe passenger BEV and PHEV sales, by country

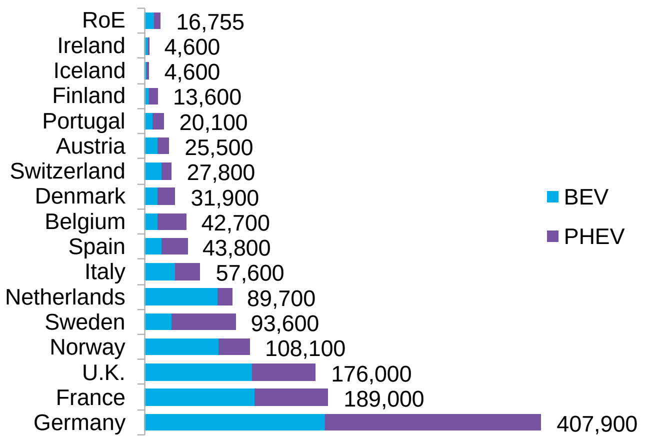
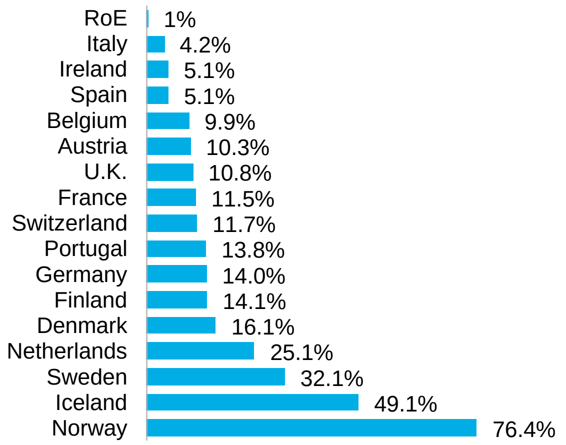


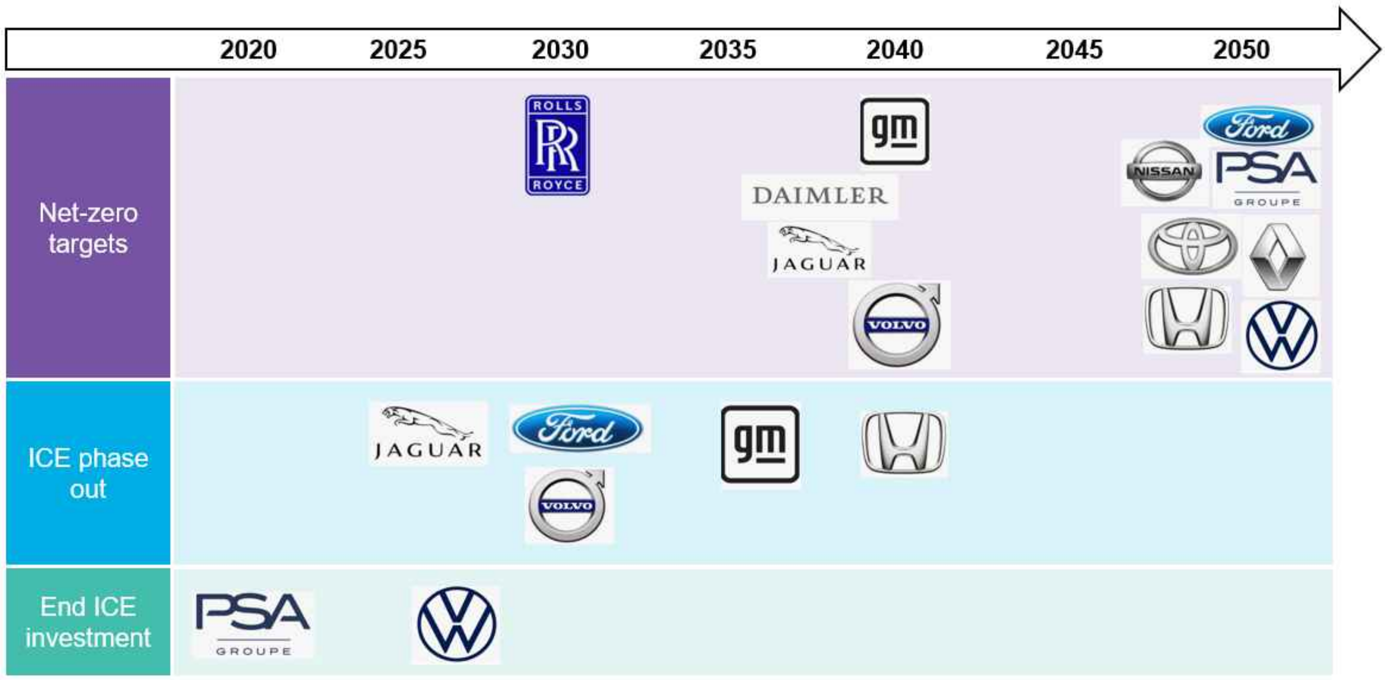
Figure 39: 2020 Europe EV share of total passenger vehicle sales



Source: BloombergNEF, Marklines, Bloomberg Intelligence, vehicle registration agencies, EV Sales Blog, EAFO. Note: Europe data includes EU27 countries plus Norway, Switzerland, Iceland and the U.K. EV sales include BEV and PHEV sales.

While France's target is still 19 years away, the U.K. will have considerably less time to scale up to 100% adoption by 2030 – which also indicates that EV sales in the country will have to grow very rapidly in the next five to six years in order to get there. Such targets in the larger auto markets can also be challenging from the supply-side perspective. However, some of the major global automakers are also increasing their ambitions in this area (Figure 40). In 1Q 2021 alone, four automakers announced new plans to phase out sales of combustion vehicles.

Figure 40: Automakers' drivetrain development targets

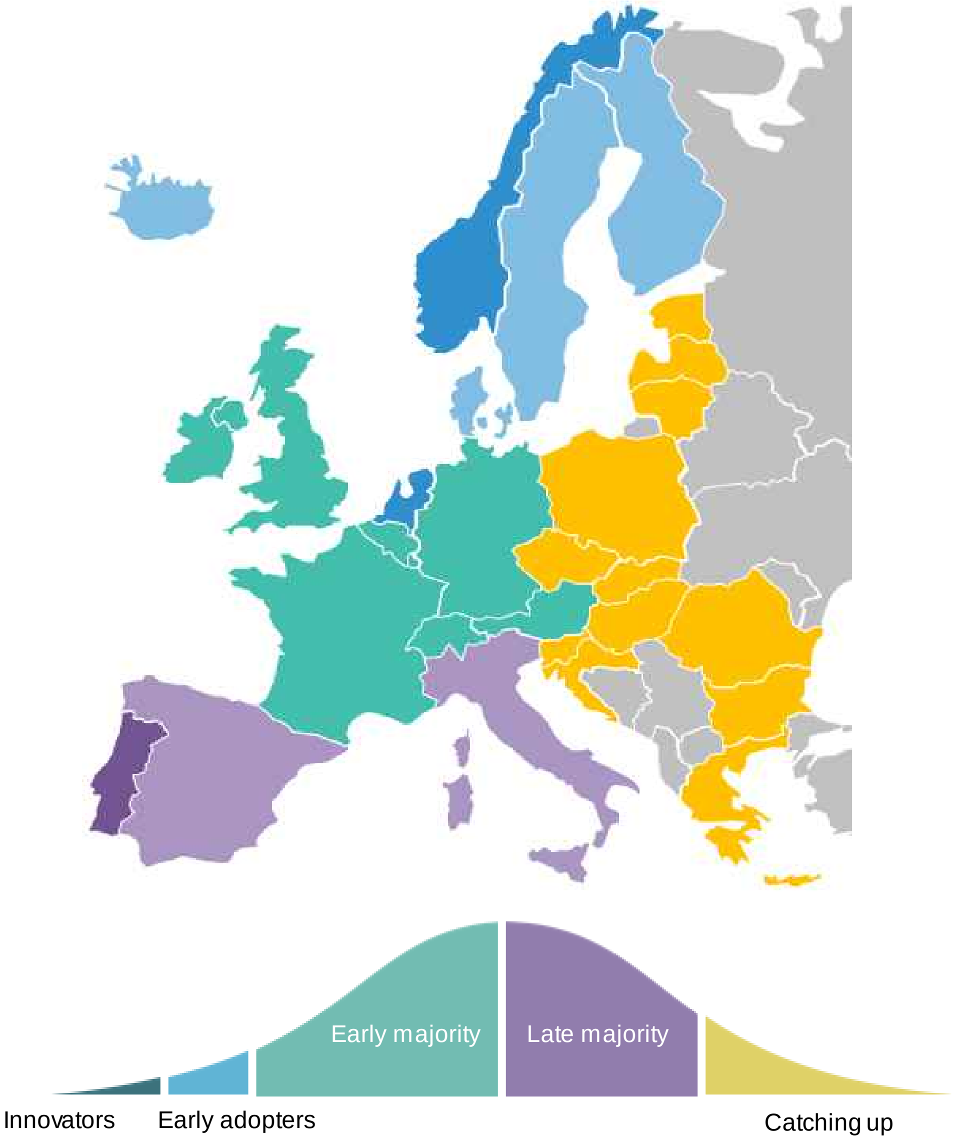


Source: BloombergNEF. Note: Ford ICE phase-out target is for Europe only.

Country groupings

To compare EV adoption trajectories across Europe, we grouped the countries in the EU, plus the UK and EFTA countries into four distinct regions: the initial innovators and early adopters, the early majority, the late majority and those catching up on EV adoption (Figure 41). The main metric for consideration is the current BEV share of vehicle sales. A number of additional metrics include total sales, fleet size, population size and GDP per capita, as well as supporting policies, phase-out targets and charging-infrastructure development.

Figure 41: Distribution of adoption groups and country grouping



Source: BloombergNEF. Note: Several countries might be slightly ahead of the region within which they are grouped. Notable are Norway, the Netherlands and Portugal, which are colored darker for this reason.

Our country groupings are as follows:

Nordics+ includes Scandinavian countries like Norway (BEV and PHEV share of 76% of sales in 2020) and Sweden (32% share), which are leading with strong support mechanisms and high adoption shares. The Netherlands (25% share) can be counted as one of these pioneering countries in terms of EV adoption, policy measures and charging infrastructure development in Europe and hence is grouped together with the Nordics. Despite boasting an average EV sales share of 17% BEV and 12% PHEV in 2020, these are relatively small markets and only accounted for 8% of all vehicle sales in Europe in 2019.

The major **Western European** markets of France and the U.K., where BEVs and PHEVs had an 11% share in 2020, and particularly Germany (14% share in 2020) show rising EV adoption, strong policy support, and large-scale infrastructure roll-out. Smaller surrounding countries like Austria, Switzerland and Belgium are on similar trajectories. Car sales in the region account for 61% of all units sold in Europe. The average BEV sales here jumped from 1.7% in 2019 to 5.7% in 2020**.**

Southern European countries have been slightly more limited in their support for EVs, but Italy has shown a rapid increase in EV sales in 2020 (from 0.7 to 4%) and regional infrastructure build-out is under way. Spain is catching up to its neighbors (5% EV sales in 2020), whereas Portugal has higher EV sales (12% BEV and PHEV share in 2020). The Southern European countries represent 21% of all vehicle sales in Europe, yet less than 8% of EV sales in 2020.

Electric vehicle adoption is just getting started in most **Eastern European** countries. EVs are picking up and have surpassed 1% of sales in many countries in this group in 2020 for the first time. Poland is the major market in this region, responsible for half of overall sales. Most of these markets are characterized by relatively low sales of new vehicles (10% of all new vehicles sold in Europe) in comparison to the share of the overall European fleet of vehicles on the road (21%) and share of the population (22%). This is due to a large second-hand market through imports from other parts of Europe. The motorization rates are similar to most other regions in Europe, but the average vehicle age is higher. Greece has been categorized in this group as well, mainly due to low turnover in recent years. Several of these countries, including Estonia and Slovenia, show slightly higher EV sales.

Table 6: Overview of country comparison metrics by region

	Nordics+	Western	Southern	Eastern
EV share of total sales 2020	17.3% BEV, 12.3% PHEV	5.7% BEV, 5.1% PHEV	2.2% BEV, 2.5% PHEV	1.4% BEV, 1.1% PHEV
EV share of total sales 2019	10.4% BEV, 3.7% PHEV	1.7% BEV, 1.1% PHEV	0.7% BEV, 0.5% PHEV	0.5% BEV, 0.3% PHEV
Total sales	1.4M (8%)	10.5M (61%)	3.6M (21%)	1.7M (10%)
Fleet size	22M (8%)	133M (47%)	70M (25%)	59M (21%)
Population	45M (8%)	251M (48%)	118M (22%)	115M (22%)
GDP/Capita	46k EUR/year	38k EUR/year	26k EUR/year	14k EUR/year
EV policy	Multi-layered support, phase-out targets	Strong support, some phase-out targets	Moderate support, some phase-out targets	Largely limited support, some phase-out targets
Charging infrastructure	Large-scale roll-out underway	Large-scale roll-out underway	Low-density network	Low-density network

Source: BloombergNEF, Bloomberg Economics, Marklines, OECD, IMF, World Bank. Note: Except for 2020 EV sales, other values based on 2019 values to exclude effect of Covid-19.

The BEV adoption outlook in the following sections is done in two parts: a bottom-up short term forecast covering 2021-2025, and a top-down, techno-economic consumer-adoption approach from 2026-2035, for each of the four country groups.

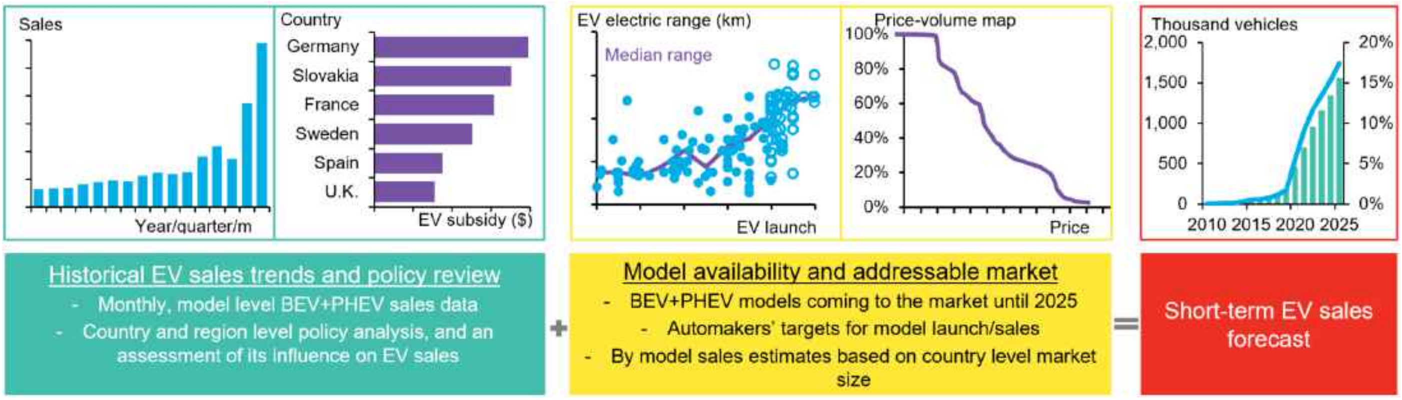
4.2. Short-term methodology and forecast, 2021-2025

Short-term methodology 2021-2025

In our short-term EV sales forecast methodology we take a bottom-up approach. We begin by updating our database of upcoming EV model releases in Europe. To compile this database we rely on company announcements, filings and third-party data.

We then project EV sales for each market in Europe by taking into account historical EV sales trends, model availability as well as any active relevant policies in place, including purchase subsidies and regulatory mandates (Figure 42).

Figure 42: Short-term EV adoption forecast methodology



Source: BloombergNEF

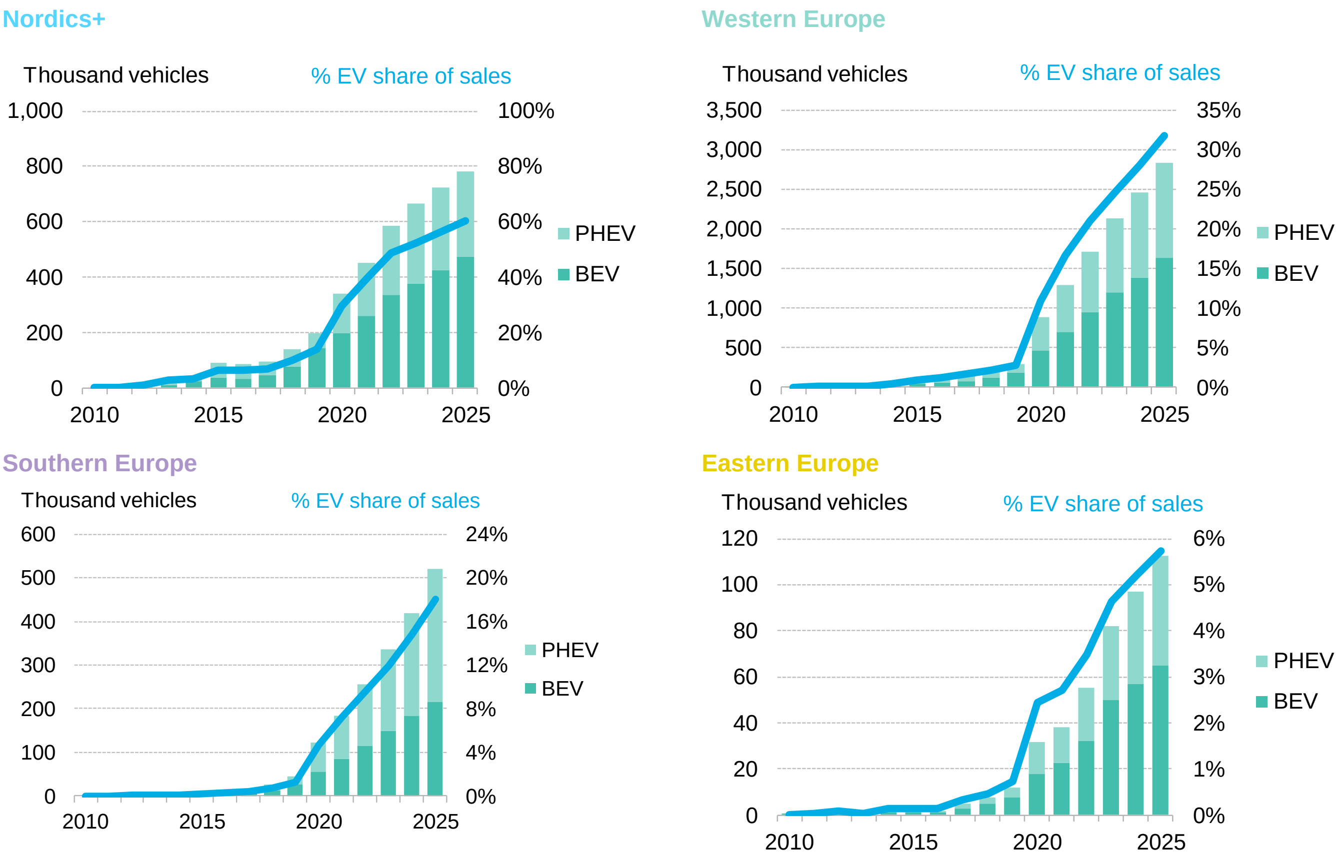
In the model review we take into account announced upcoming EV models that are to be introduced to the market until 2025. Considering their characteristics – drivetrain type, segment, range and price[7] – we use regression analysis to estimate their addressable market in any given country, and their potential sales in their specific segment up to 2025. Although we do not take concept models into consideration, we do account for various automakers' announcements as to their targeted sales or planned model introductions. For example, Hyundai Motor Group announced its plans to introduce 23 battery electric vehicles globally by 2025 – in our short-term forecast we have estimated their sales in each country, based on an assumed segment those vehicles will address. In the policy review, we look at the availability of purchase subsidies in the analyzed countries to understand the eligibility criteria – for example price caps, EV range etc. – and their influence on the upfront price of an EV model. We use that knowledge to buffer model-level sales – where we believe that generous subsidies can potentially boost a specific model's sales beyond what historical sales trends would indicate.

[7] We use various inputs to estimate the prices of upcoming BEVs: manufacturers' suggested prices, where available; prices for comparable vehicles in the same segment; or manufacturers' expectations as to the competitive vehicles with a given BEV. For upcoming models, where less information was provided by the manufacturer (usually models expected to come to the market towards the end of the short-term forecast period) we incorporate our expectations of lower cost BEVs hitting the market, as more models become available and battery prices fall further.

Short-term forecast 2021-2025

European EV sales continue to grow at a fast pace. Several European countries have already left the early-adopter phase of the market. Norway finished 2020 with BEVs and PHEVs at 76% of sales, Iceland at 49%, Sweden at 32% and the Netherlands at 25%. These are small auto markets, but they highlight how quickly things are changing. Last year, 2020, was a breakthrough for EV sales in some of the major markets in Europe as well, and those are now quickly catching up.

Figure 43: Short-term EV adoption forecast for Europe



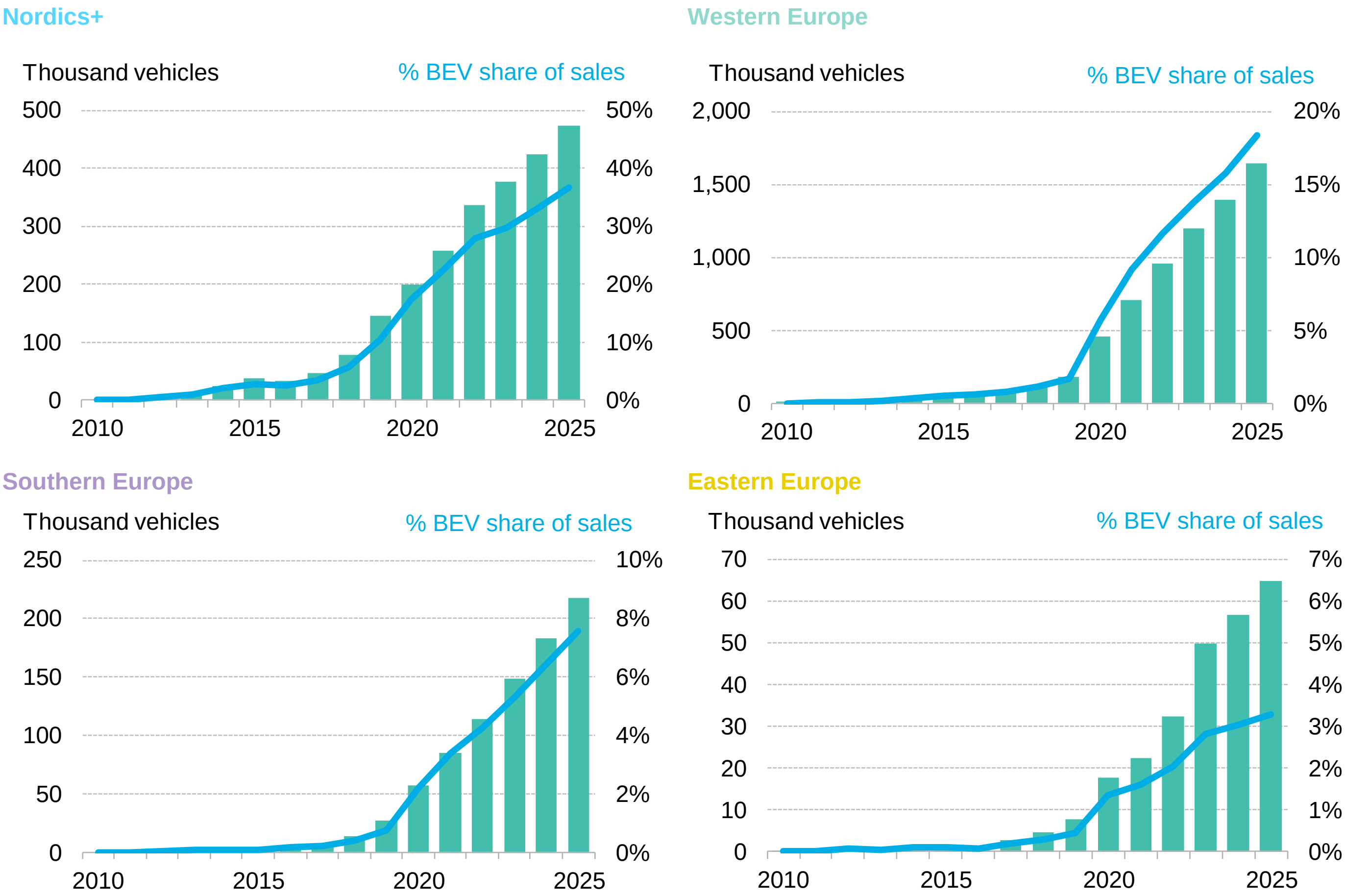
Source: BloombergNEF. Note: Each region on a different scale.

We expect electric vehicle sales in Europe to continue to grow in 2021 to just over 1.9 million units. This is up 43% from the previous year. The growth in sales will continue to be driven mainly by the CO_2 regulations. More importantly, from 2021 the average emissions of all newly registered cars from a manufacturer will have to be below the target, including the worst performing 5%, which were exempt in 2020. This means that some of the more popular automakers in Europe that rely on sales of SUVs – including Daimler or Audi – will need to double down on EV sales. The addition of the 5% least efficient vehicles to the compliance pool will also likely push PHEV sales up in the region in 2021. Automakers are responding by increasing their sales targets – Volkswagen aims to double its electric car sales in 2021, while BMW plans to increase EV sales by more than half, at the same time doubling its sales of pure electric vehicles – and by adding new electric models to their offering.

Our short-term EV sales forecast brings EV sales in Europe to a little under 4.3 million units by 2025, or around 28% of all passenger vehicles sales in the region. Adoption in the four specified groups will vary widely and not all markets will move at the same pace. While EVs reach 60% market share in 2025 in the Nordics+ and 32% in Western Europe, the adoption still hovers under 20% in Southern European countries and barely reaches 6% in Eastern Europe (Figure 43).

Battery electric vehicles will continue to contribute over half of the expected EV sales in the region. BEVs will be responsible for around 37% of all passenger car sales in the Nordics+, 18% in Western Europe, just under 8% in Southern Europe and little over 3% in Eastern Europe by 2025 (Figure 44).

Figure 44: Short-term BEV adoption forecast for Europe



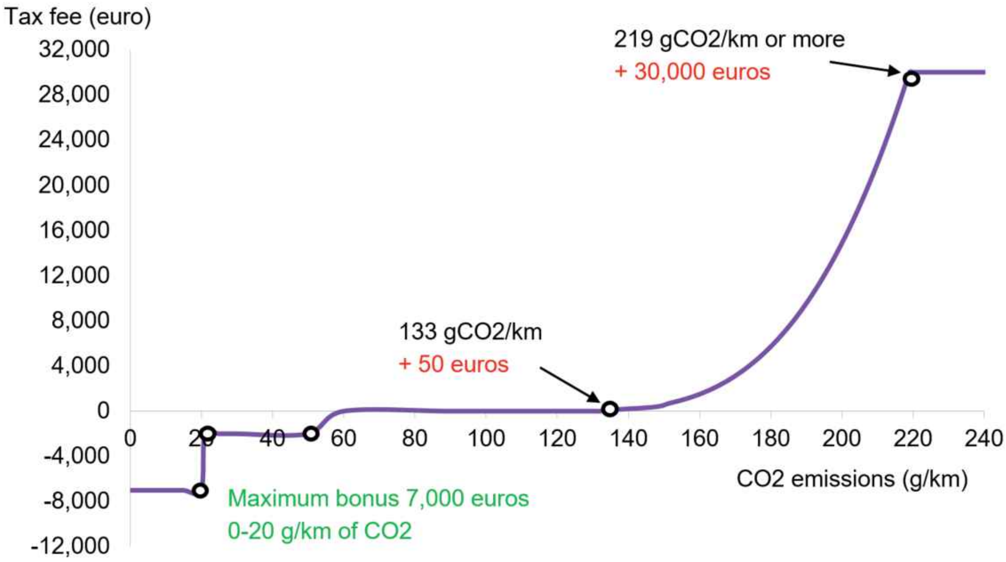
Source: BloombergNEF. Note: Each region on a different scale.

There are several reasons for the observed regional differences. First, countries in Western Europe and the Nordics have some of the most comprehensive support for EVs in Europe, and globally. Favorable tax discounts in Norway mean that EVs have been cheaper to buy there than ICE vehicles for several years now. This has led to the accelerated EV adoption in the country.

The *bonus-malus* systems in place in Sweden or France allow for the continued offering of hefty BEV and PHEV purchase subsidies (*bonus*), which are paid for by the penalizing CO2 tax levied on the purchase of most polluting vehicles (*malus*). For example, in France, buyers of new BEVs are eligible for a purchase incentive of 7,000 euros, while buyers of vehicles emitting 219g CO2 per kilometer or more have to be prepared to pay a 30,000 euros CO2 tax on top of their purchase price (Figure 45). Such a system effectively moves buyers of heavier vehicles toward plug-ins.

Similarly in Germany, EV purchase subsidies – raised in 2020 to 9,000 euros as part of the Covid-19 stimulus package – contribute more than 20% to the price of an average BEV in the country[8]. And the level to which EV purchase subsidies can lower the upfront price of an EV in any given country matters. EV purchase subsidies on offer in Spain or Italy effectively contribute only around 10% to 12% of the average BEV price in the two countries.

Figure 45: France bonus-malus system



Source: BloombergNEF, French government.

However, purchase subsidies alone are not enough to significantly boost EV adoption. In countries like Poland or Hungary, EV subsidies can also contribute more than 15% to the average price of a BEV. Despite this, even in 2020, EVs made up just a fraction of total passenger car sales in the two countries.

Countries in the Eastern Europe group (Figure 41) are predominantly second-hand car markets and are not the focus for automakers to direct their newly released EV models. For compliance with the CO2 targets, countries with high share of new car sales attract the majority of EV supply. Additionally, automakers are likely not yet considering the Eastern and Southern European consumers' "desirability" criteria, when deciding which EVs should be released next. Therefore, the "desirable" EV – meeting the price, segment, range criteria of an average buyer from the groups of Southern and Eastern European countries – may not exist yet. This is changing slowly, as brands more popular in the region, like Skoda or Dacia, begin to release new EV models – but

[8] We use the Tesla Model 3 (Standard Range Plus version) as a reference vehicle. Prices of the model are country-specific: Germany at 39,990 euros, Spain at 45,090 euros and Italy at 48,990 euros. Subsidy value used (excluding any available scrappage bonus additions): Germany at 9,000 euro, Spain at 4,500 euro and Italy at 6,000 euro.

it does show that model availability and locally preferred brands should not be underestimated when discussing the drivers for EV adoption.

Why model availability matters

1. EV models addressing popular segments can make or break a local market: A good example of this is the Mitsubishi Outlander PHEV – the first PHEV SUV globally. It was first introduced in Europe in late 2013. In 2014, EV sales in Europe jumped 85% compared to 2013, with the Outlander quickly becoming the leading EV model in the region, contributing 21% of total EV sales that year.
2. Affordable, high spec, mass market EVs can make the segments lines blurry: and therefore significantly boost their addressable market. Tesla Model 3 is an excellent example. Introduced in late 2017 in the U.S., its production was slowly ramping up, until sales went up rapidly in 2018. The Tesla Model 3 contributed 39% to the total EV sales in the U.S. that year. This is also when EV sales in the U.S. increased 80% compared to 2017. They have been relatively flat since then.

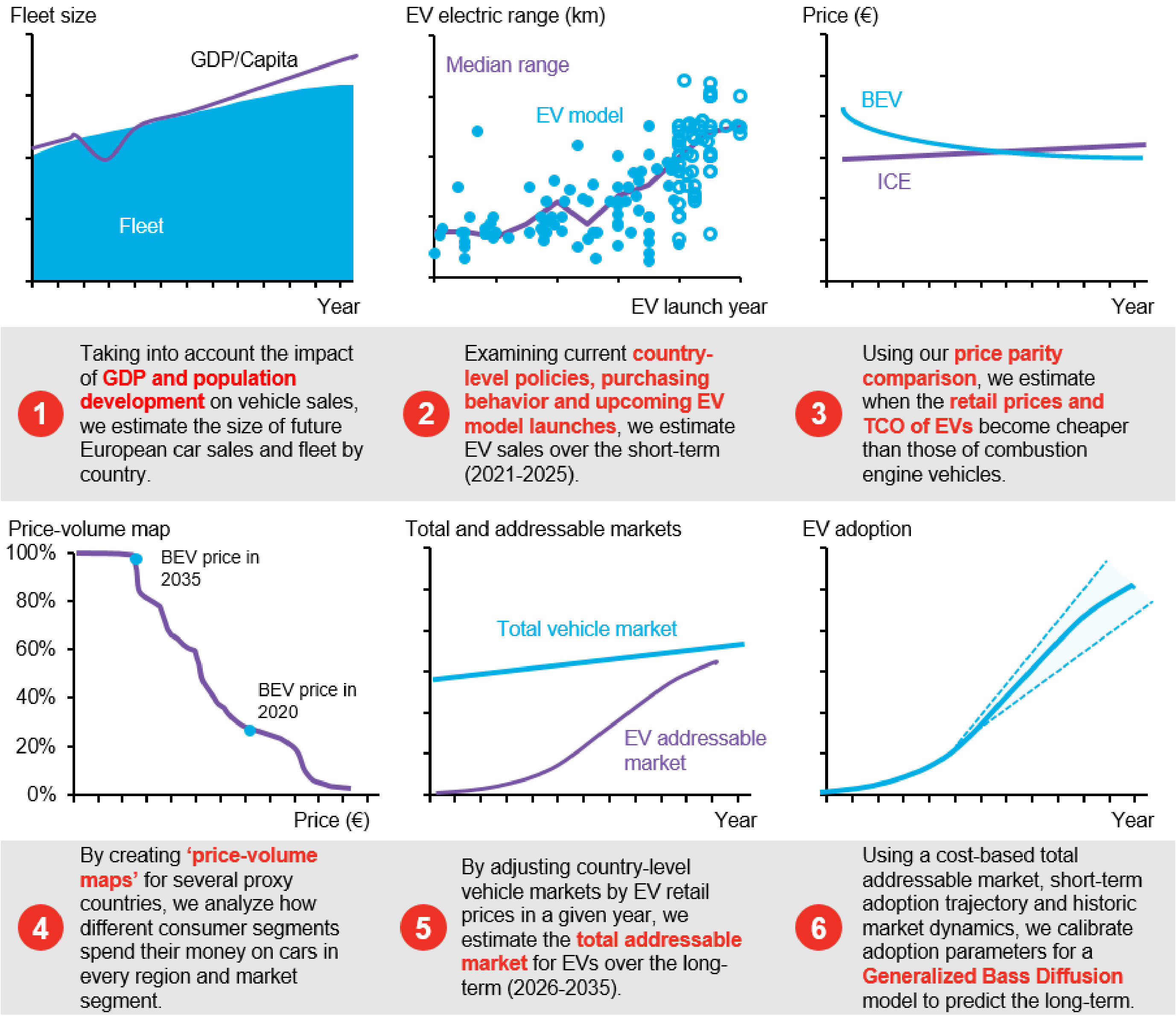
   In July 2018, Tesla sold around 14,000 units of the Model 3 in the U.S. This was remarkable since it was the highest monthly sales on record for a single EV model sold outside of China. Moreover, it was the best-selling premium mid-sized sedan in the U.S. that July and it outsold other leading vehicles in that segment – the BMW 3 Series, Infinity Q50, Mercedes C-class and Audi A4, for example. A year prior, none of the ICE models in the premium mid-sized segment in the U.S. achieved monthly sales of 14,000 or more. Most importantly though, Tesla revealed that the top five cars that the Model 3 buyers traded in (if they were not trading in an older Tesla model) included the Toyota Prius, the BMW 3 Series, the Honda Accord, the Honda Civic and the Nissan Leaf – all with a lower price tags than the Model 3. This indicates that many Tesla Model 3 buyers were trading up, which could indicate that the Model 3 is re-defining, or at least bending, current car segment categories.

4.3. Long-term methodology and forecast, 2026-2035

Long-term methodology 2026-2035

Our long-term forecast approach has six main steps (Figure 46 on the following page):

Figure 46: Simplified battery electric vehicle adoption forecast methodology



Source: BNEF. Note: Charts illustrative only.

1. **Sales and Fleet:** To build our adoption forecast, we develop an outlook for total vehicle sales over time. We start with a regression of historical sales and GDP-per-capita for each individual country in Europe. Based on country specific economic development trajectories from the OECD and IMF, we forecast future total sales and adjust this for population development using data from the World Bank. In the short-term we assume a gradual post-Covid recovery. At the same time, we also calculate the development of the fleet size, as this helps determine how quickly rising EV sales affect the electrification of the vehicle fleet. This has knock-on effects on the speed of consumer adoption, which to some measure impacted by what people see driving around.
2. **Short-term dynamics:** The short-term EV sales forecast, described in the previous section, in combination with expected total sales provides us with a view on EV adoption

share in the next five years. Combined with a timeline of historic EV sales dating back to 2015, this gives us a timeline of 10 years on which we can calibrate adoption for the 10 years ahead. For some countries, like Norway, Sweden and the Netherlands, where there is more data available dating further back, we use these to additionally inform our adoption parameters.

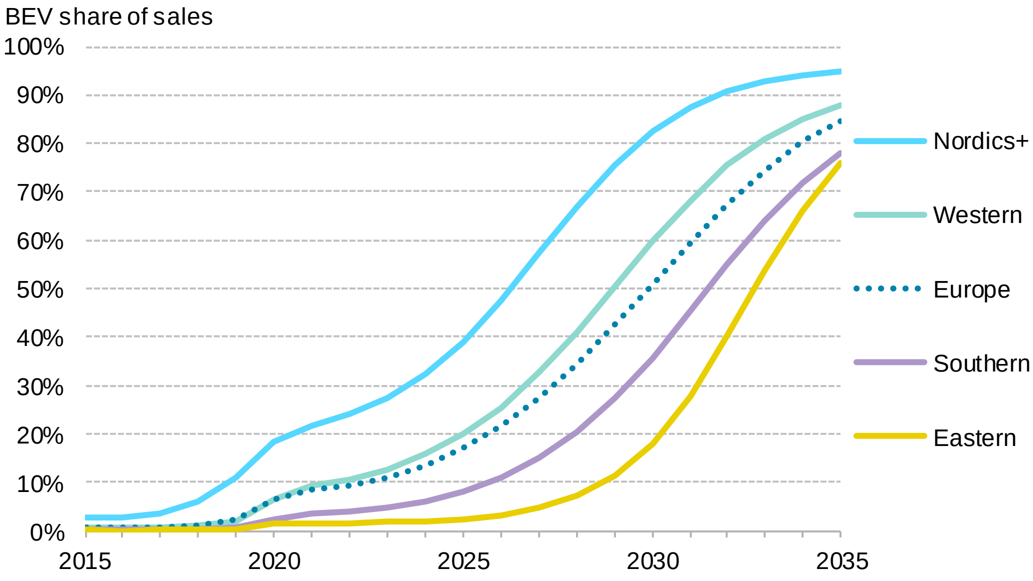
3. **Price parity comparison:** We use our price parity work as described in Section 3 to calculate upfront prices for ICEs and BEVs. However, while consumers might mainly focus on the sticker price of a car, companies particularly also focus on total cost of ownership (TCO). Taking into account factors such as fuel prices, annual kilometers travelled, residual value and maintenance cost, we calculate TCO values for both BEV and ICEs. As EVs reach TCO parity earlier than upfront price parity, this functions as an additional driver.
4. **Consumer price segments**: We analyze the car market by looking at relationships between prices and sales volumes in different countries and segments. Such 'price-volume maps' give an indication of consumers' spending patterns and provide the economically potentially addressable market for a BEV at a particular price point.
5. **Total addressable market:** As the average price of BEVs drop, the share of consumers for whom an EV would be a cheaper option rises. The speed at which this happens depends on factors such as distribution of the price-volume maps by segment and region, with larger pockets of consumers in certain price segments. Other potential factors affecting the market dynamics that could slow down or accelerate a shift to EVs, such as charging infrastructure availability and the role of shared mobility are discussed in Section 4.4.
6. **Adoption curve:** In the long term, we think the adoption of privately owned EVs is fundamentally a question of consumer technology diffusion and we use an adapted Generalized Bass model to capture such effects. This is done through BloombergNEF's proprietary EV Adoption Model, which is calibrated on historical adoption data and observed market dynamics. It includes consumer 'innovation' and 'imitation' factors, and integrates price elasticity of demand effects that reflect our forecasts for both vehicle up-front prices and total cost of ownership.

The long-term adoption forecast is demand-driven and does not assume that the currently legislated 2030 CO2 emissions targets are met. As such, the forecast does not assume any other regulatory support for BEVs in the time period to 2035.

Long-term forecast 2026-2035

European BEV sales reach 85% of total by 2035 under the current base case trajectory, having already crossed 50% by 2030 (Figure 47). BEV sales growth slows slightly between 2020 and 2025, even though sales continue to increase steadily, because of the jump in 2020 to meet the 95g CO2 target. Adoption accelerates quickly from 2025 as different segments hit price parity in quick succession and more EV models are launched.

Figure 47: Battery electric vehicle share of total annual passenger vehicle sales by region in Europe: base case scenario



Source: BloombergNEF. Note: The Europe adoption curve shows the adoption for all four regions combined according to their sales. Includes adoption of battery electric vehicles (BEV) only; does not include plug-in hybrids (PHEV). Base case shows trajectory under current economic development and policy measures, but does not take into account any constraints due to charging infrastructure, raw material availability or other factors.

The Nordics+ are expected to charge ahead on BEV adoption, with Norway largely on track to meet its 2025 ICE phase-out target. The saturation of the Norwegian market causes some deceleration on the average adoption growth across this region. Adoption in Denmark, Sweden and Finland rises quickly in the years ahead. Changing stimulus measures in the Netherlands have caused the market go forward and backward several times, but overall this region reaches very high BEV shares, hitting 39% in 2025, 82% in 2030 and 95% in 2035 (Figure 47).

Norway's trajectory provides a playbook to understand aspects of adoption in other countries as well. Battery electric vehicles there have been at similar prices with ICEs for a number of years. Still, it takes time after that parity year for adoption to exceed 50% and grow further. Some of the restrictions, such as limited model availability and patchy charging infrastructure networks, are gradually being lifted for other countries in early stages of adoption. However, other hurdles may remain, such as the need for additional BEV price declines to reach wide parts of the auto market in less wealthy places, as well as an increased consumer acceptance of the new technology.

The adoption trajectory **in Western Europe** is also rising and is a case in point. In Germany and France, generous subsidies and increased model offerings from domestic manufacturers provide support and choice to consumers, and help the region gain momentum. The U.K. is also developing well in terms of roll-out of charging infrastructure and more BEV models on sale – now and in the near future – in the popular SUV segment. The region becomes the second highest for BEV adoption and the biggest market for BEVs, which reach 20% of sales in 2025, 60% in 2030 and 88% in 2035 (Figure 47). The rate of growth in Western Europe after 2025 is stronger than in the Nordics+, but not the highest in Europe after 2025.

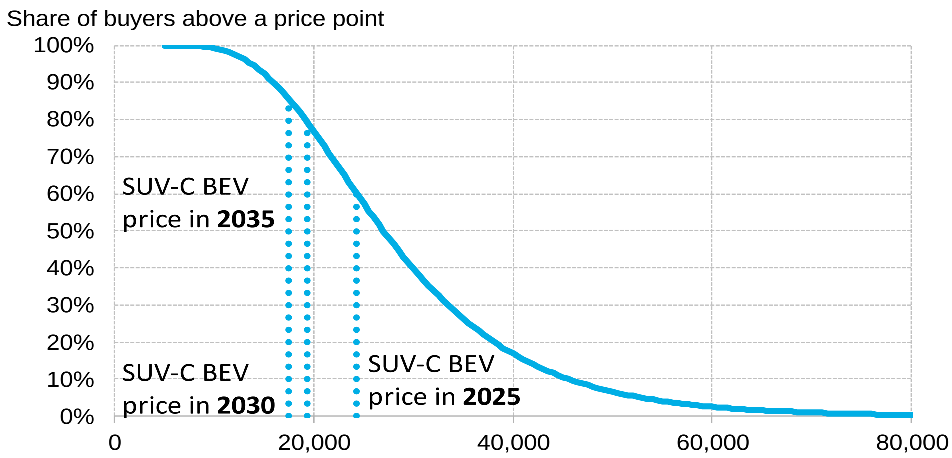
In particular, **Southern Europe** and **Eastern Europe** grow the fastest in the 2020s, as they start from a low base (Figure 47). In Southern Europe, signs are there to demonstrate a change in consumer demand for EVs in general, as Portugal (in the last couple of years), and Italy and Spain more recently experienced strong demand for electric cars. Growth rates are set to accelerate in the region and will be even higher in the second half of the current decade than between 2020 and 2025. During that period, all vehicle segments reach price parity, making purchasing BEVs a simpler choice than in earlier years. BEV adoption in Southern Europe reaches 8% in 2025, 36% in 2030 and 78% in 2035.

Despite cost competitiveness, it takes until 2030 for the Eastern Europe region to hit 18% BEV adoption based on the current trajectory. Consumer buying patterns will not flip overnight and the second-hand market remains larger than elsewhere in countries within that group. That limits BEV growth for several more years, and automakers may choose to sell lower-priced mass market ICE vehicles in these countries. However, this strategy will not hold for long. As EVs become more ubiquitous in other parts of Europe, there is a delayed, but very rapid increase in adoption rates closer to 2030 and beyond. In fact, between 2025 and 2030, BEV sales in Eastern Europe will grow twice as fast as in Southern Europe and more than five times over the rate of growth of the Nordics+ region. BEV adoption in Eastern Europe hits 76% by 2035.

Getting to 100%

BEV adoption in our base case slows down slightly in the early 2030s as some segments saturate. In the smaller vehicle segments, stripped down, low performance, low cost internal combustion vehicles will be hard to beat on price for some time, particularly given the assumed BEV ranges used in this analysis. This highlights an important difference between price parity in relation to average prices in a vehicle segment and price parity with all vehicles in that segment. Figure 48 shows that even with a BEV SUV well below the average ICE price in that segment in 2030, there are still corners of the market that remain unaddressed from a purely economic perspective. Vehicles in adjacent segments, such as SUV-B, could fill the remaining gap in that part of the market, as such vehicles could be cheap enough in the 2030s to do so. Market dynamics and potential segment shifts – eg, whether consumers are willing to buy those smaller SUVs – are likely to affect the speed and difficulty of reaching full BEV adoption in all segments.

Figure 48: Price-volume map for SUV buyers in Germany



Source: BloombergNEF. Note: the price-volume map shows the share of buyers that purchase vehicles above a given price; for example, 40% of buyers purchase SUVs costing 30,000 euros or more and the other 60% purchase SUVs that cost less than 30,000 euros; here we have combined all SUV sub-segments together.

In order to test what reaching 100% BEV adoption would look like, we built an accelerated scenario for each region, shown in Figure 49 to Figure 52. This scenario assumes that governments introduce more supportive policies that push the market toward much faster BEV adoption and, hence, does not consider additional potential constraints, such as charging infrastructure, raw material availability for batteries and other factors. In particular, short-term BEV volumes are higher by 2025, and the earlier sales momentum forms the basis for higher consumer adoption in the second half of the 2020s. At the tail-end, we assume additional support ensures a reduction in the natural slow-down that would be caused by hard-to-reach pockets and more difficult use cases. Such a trajectory relies on more expanded policy support for consumers and businesses, as well as on charging infrastructure. A non-exhaustive list of the potential tools is outlined in page 45 below.

In the accelerated scenario, the Nordics+ maintain an almost linear growth trajectory in the coming decade to hit 100% BEV sales by 2030. If Norway were to keep its current growth it could hit 100% by late 2023. However, the last 10% of any market is challenging and likely to be hard to fill. In addition, countries such as Sweden and the Netherlands have relied to PHEVs in the past, but this scenario assumes that they shift exclusively to BEVs.

In Western Europe, the U.K. already has announced updated phase-out targets (100% BEV + PHEV by 2030, 100% BEV by 2035) and is rolling out a large amount of charging network, while Germany is also investing heavily in charging infrastructure. For this group of countries, adoption has to come forward by only a couple of years to place them in the trajectory needed to hit 100% of sales just after 2030. Risks in these countries include any delay in the rollout of BEVs in the SUV segment, with buyers turning to PHEVs to meet their needs.

The accelerated adoption in Southern Europe could be similar to the 100%-trajectory of the Western countries, but delayed by a few years. The car markets in these groups have some similarities and as adoption increases in the region, BEVs start to become cost competitive. Still, overall BEV sales will have to increase by more than 40x to reach a complete ICE phase-out by 2035.

Hitting 100% BEV adoption in the countries of the Eastern Europe group will the most challenging. Due to very low adoption currently, and a limited outlook for BEV sales growth in the short-term, the region has to experience an unprecedented sales acceleration to reach the 2035 target. BEVs at the lowest end of our estimated pre-tax retail prices will be needed to spearhead adoption around 2025 in the region. That may require lower driving ranges or different, and cheaper, battery technologies.

Figure 49: Base case and accelerated passenger battery electric vehicle share of sales in Nordics+

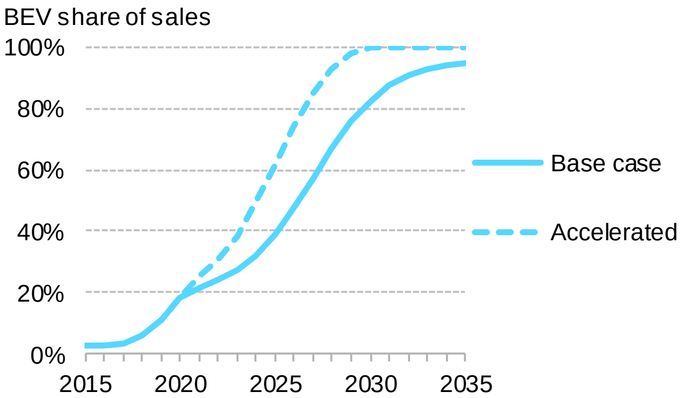


Figure 50: Base case and accelerated passenger battery electric vehicle share of sales in Western Europe

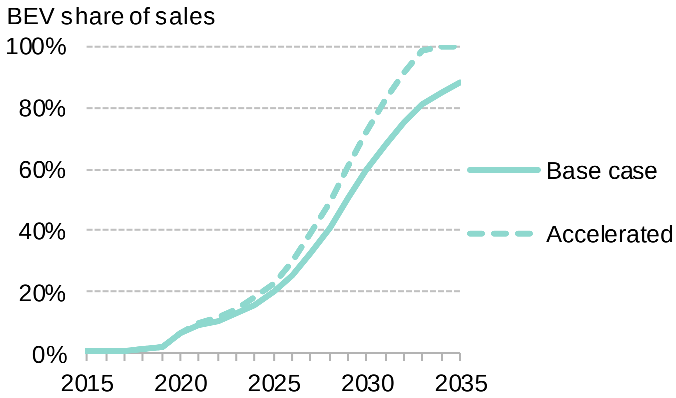


Figure 51: Base case and accelerated passenger battery electric vehicle share of sales in Southern Europe

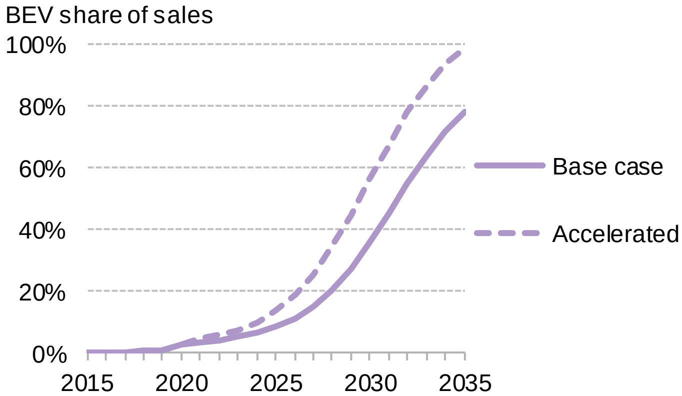
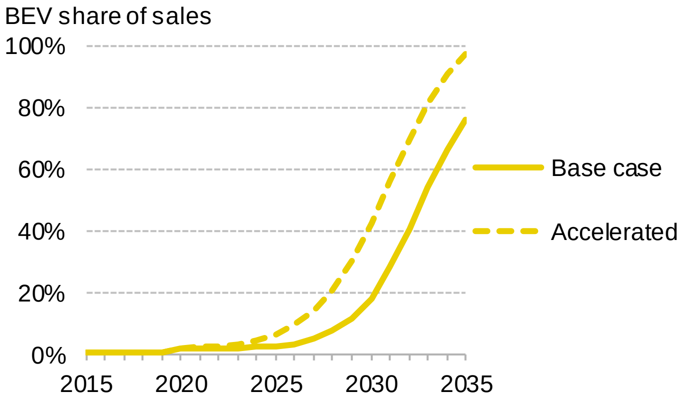
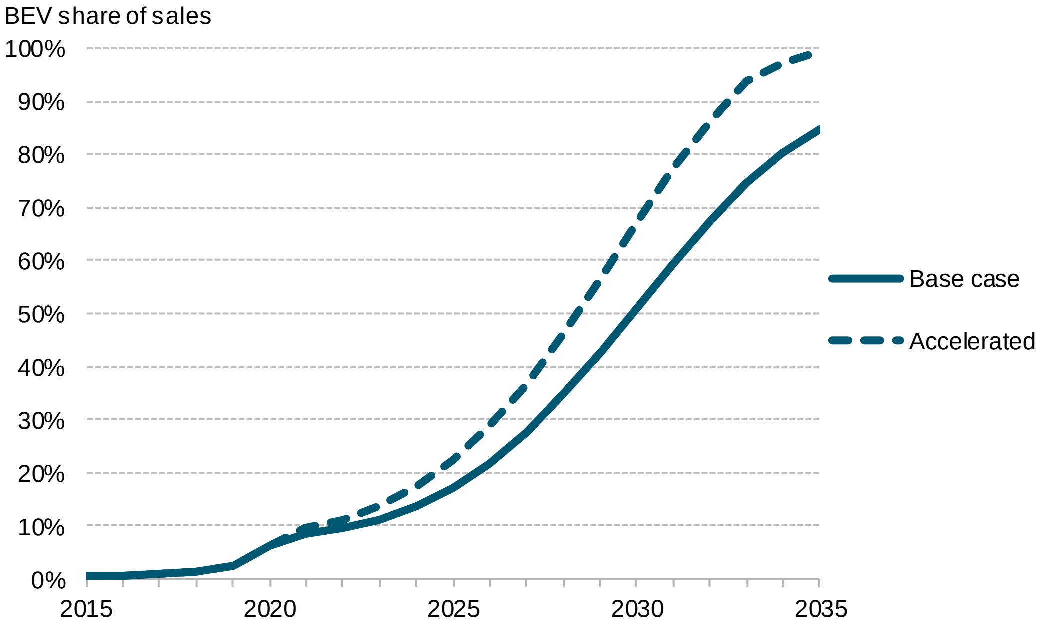


Figure 52: Base case and accelerated passenger battery electric vehicle share of sales in Eastern Europe



Source: BloombergNEF. Note: Includes adoption of battery electric vehicles (BEV) only; does not include plug-in hybrids (PHEV). Base case shows development trajectory under current technology outlook and policy measures. Accelerated shows potential scenario under additional stimulus

Figure 53: Base case and accelerated passenger battery electric vehicle share of sales in Europe



Source: BloombergNEF. Note: The Europe adoption curve shows the volume weighted average adoption for all four regions combined. Includes adoption of battery electric vehicles (BEV) only; does not include plug-in hybrids (PHEV). Base case shows development trajectory under current technology outlook and policy measures. Accelerated shows potential scenario under additional stimulus

Overall, BEV adoption in Europe follows a trajectory similar to the curve for Western Europe, which represents the majority of the market (Figure 53). Adoption reaches 22%, 67% and 100% of total sales by 2025, 2030 and 2035, respectively, in the accelerated case.

Additional policy options that can be considered to support the accelerated scenario

A full assessment of policy tools to achieve the accelerated scenario is beyond the scope of this analysis. Here we highlight several approaches that could be used to support this:

- Tailpipe CO2 emissions targets that are stricter and stretch further in time than current rules.
- Support for charging infrastructure expansion to remote and otherwise under-served locations.
- Consumer subsidies targeted to low-priced EVs to help access the full range of buyers and to the purchase of second-hand electric vehicles.
- Mandates for the electrification of fleets, including of those of governments and transport operators, such as mobility service providers.
- Tighter municipal regulations for vehicles entering urban areas.

Adoption of electric vans

Methodology

Total cost of ownership (TCO) is the main factor for forecasting the share of different powertrain technologies in commercial vehicles. TCO quantifies the present value of all relevant costs in owning and running a vehicle. It includes capital, fuel, maintenance and tires, and is normalized over the total distance traveled throughout the vehicle's usage period. The calculations here exclude driver wages. We adjust the calculations to penalize electric drivetrains for low model availability and undeveloped fueling infrastructure. However, we expect that by the mid- to late-2020s electric vans will be easily accessible to buyers.

We then stack the TCOs of the electric, diesel and gasoline vans (for both light and heavy) and estimate the market shares of the different technologies based on the ranked relative costs. In this process, the sales share of a particular fuel declines rapidly the further away it is from the cheapest option.

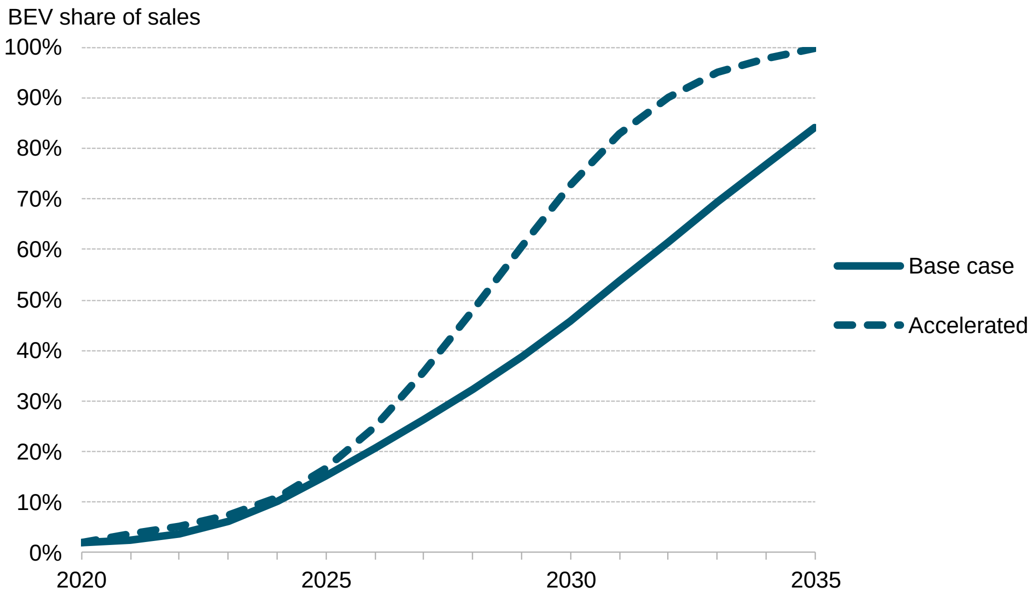
Forecast, 2021-2035

The total cost of ownership of light vans can already be lower than that of diesel equivalents for some duty cycles, especially in countries with the highest diesel- or gasoline-fuel costs. The TCO of both light and heavy vans becomes on average the lowest within the next few years. Such economic advantage drives the adoption of these vehicles in Europe to about 84% by 2035 (Figure 54), while all four country groups reach adoption shares between 70% and 86%.

The group of Western European countries starts from a higher base and grows the quickest. Still, the adoption of electric vans over time takes hold similarly in all country groups, more so than that of passenger cars. Another difference is a steadier adoption trajectory. That is due to the more economics-driven decision to purchase such vehicles. As the TCO advantage of those light-duty commercial vehicles steadily increases, wider parts of the market choose to own and operate electric vans.

Some hurdles that we expect to be gradually resolved are: the initially low model availability of suitable vehicles and the currently few charging infrastructure solutions for fleets. In addition, the predominance of smaller fleet – or even single vehicle – owners means that, until upfront cost price parity is reached, new financing tools would be required to allow capital constrained buyers' early access to such vehicles. In the next few years, large fleet owners and users will be the main buyers of electric vans, as many of them also put forward decarbonization and sustainability plans.

Figure 54: Base case and accelerated battery electric van share of sales in Europe



Source: BloombergNEF. Note: two vans classes are used, light and heavy vans, whose specifications are shown in Table 1 and Table 3.

4.4. Other considerations affecting BEV adoption

The BEV outlook in the previous sections is based on our assessment of the techno-economic factors driving adoption. There are several areas that are not considered in this analysis that could still impact adoption. These include, but are not limited to:

- **Company cars:** No differentiation was made in the analysis between private and company car sales. Company cars are a large share (more than 55% of sales in Europe in 2019[9]) of sales in the European market and a major driver of EV sales due to various tax incentives in place in different countries. Additionally, total cost of ownership (TCO) and residual values are often important factors for company car purchases. The higher focus on TCO price parity, which generally comes 1-2 years before up-front price parity, and potential further regulation could speed up adoption of electric vehicles in the corporate fleet. Sustainability considerations and corporate image concerns could provide a further push for electric company cars.
- **Shared mobility:** Shared cars including those deployed in car-sharing schemes, taxis and ride-hailing services. These have not been treated separately in the analysis. The high annual distance travelled of these vehicles – like other company cars – makes this part of the market more sensitive to TCO. Additionally, these vehicles are mainly deployed in urban environments, where air-quality concerns are rising and regulations are getting tighter. This will likely push these services to electrify faster than privately owned passenger cars. These services can also reduce private car usage, though the data here is mixed and many of the

[9] Company cars include vehicles owned by corporations rather than individuals and can include cars provided to employees, rental cars, but also cars owned through a corporate structure.

trips they displace are from other modes like public transport. We have not included the impact of shared vehicles and the rise of potential robotaxis in this report.

- **Other drivetrains: PHEVs, fuel cell vehicles**: The analysis in this report has focused on the cost trajectory and potential adoption of BEVs. There are several reasons for this. We do not see PHEVs as an attractive drivetrain technology in the long term, since there is no route for them to become cheaper on an up-front price basis than BEVs. The current data on the amount they are charged is also mixed, with newer studies showing lower rates of charging. We expect automakers to continue to use PHEVs primarily as a compliance tool to reach CO2 targets but it is not clear if governments and regulators will continue to treat them favorably unless the data on charging becomes clearer.

  Fuel cell vehicles (FCVs) could also play a role in the future, but with only 30,000 on the road globally today, we do not expect any large-scale adoption in the 2020s. Even if the fuel-cell vehicle fleet were to grow very rapidly and double every two years all the way out to 2040, it would still only represent around 1-2% of the global vehicle fleet. Hydrogen production and distribution costs and a lack of infrastructure are further constraints for adoption in the passenger vehicle segment. We expect green hydrogen to be a scarce resource for the foreseeable future, and for governments to prioritize using it in hard-to-abate sectors like heavy industry, marine applications, and some power generation as seasonal storage in grids with high shares of renewable generation.

- **Raw material constraints.** We have not factored in any raw material constraints for the adoption analysis in this report. In practice, interest in battery materials is rising quickly, with prices of lithium carbonate, lithium hydroxide and cobalt rising 72%, 47% and 58%, respectively, in the first quarter of 2021. For lithium, the recent rise in prices is welcome as prices in the last two years were not high enough to support new capacity investment. Nickel bucked the trend and prices fell after China's Tsingshan announced in March that it will seek to produce nickel matte from its nickel pig iron smelters in Indonesia. Matte is suitable for refining to battery-grade nickel, and this provides another pathway to battery grade nickel besides high-pressure acid leaching. BloombergNEF estimates that nickel needs to be around $18,000/ton to incentive new development of battery grade capacity.

  As demand for battery materials increases and prices rise, both supply and demand patterns will change. On the supply side, more investment will flow into extraction and refining. Despite this, bottlenecks are likely to emerge in some areas. Cobalt and Class I nickel look the most likely to hit deficits in the near term. On the demand side, automakers and battery manufacturers will continue to adjust battery chemistries to reflect changes in underlying prices.

- **Plant conversions and EV manufacturing capacity:** The analysis in this report does not consider any of the logistical or political challenges of switching over large amounts of manufacturing capacity to produce EVs in a relatively short period of time. Parts of the ICE supply chain in particular are concentrated in some regions where there may be pushback if local jobs and economic activity are not created in newer parts of the supply chain. Governments will need to ensure that the switch to electric drivetrains is an equitable transition.

- **Changing segment trajectories:** Different sub-segments of the auto market may develop at different speeds. Large vehicles and sports cars often are produced at lower volumes, but with higher margins for automakers. This makes these an ideal case for automakers to push electrification in these segments first, while building up their electric supply chain. The high acceleration of electric vehicles can also add to the performance for this segment of vehicles.

On the other hand, buying certain high performance cars traditionally has been linked to the engine technology of these automakers and at least some part of the market might be reluctant to switch. Automakers will look for different ways to differentiate themselves in performance and additional luxury as BEV platforms make much of the vehicle technology more commoditized.

In the past 10 years there has been a rapid rise in sales of SUV and crossover body types in different segments. In this outlook we have kept segment trajectories fixed based on sales in 2020 because predicting how segments will change in the years ahead is very difficult. However, rapid development in certain popular segments could still accelerate EV adoption, while focus on other segments could result in the opposite.

- **Changing consumer demand:** Rising incomes and changing demographics including aging and urbanization can cause changes in consumer demand and spending habits. Other less tangible factors like cultural viewpoints might also change over time, potentially resulting in different use cases for vehicles and shifting of car trips into different modes of transport for certain trip lengths where trains or bikes might actually be more suitable. We have kept the shape of our consumer demand distribution similar across years in this analysis, but acknowledge these effects might change the segments of consumers buying a car at different price points.

Charging infrastructure

EV charging infrastructure constraints are specifically not addressed in the BEV adoption scenarios, but it is worth understanding the current state of the market, and how this could affect BEV adoption in the future.

The global public charging network grew 48% in 2020, compared to the previous year, to reach 1.36 million connectors. At the end of 2020 there were 810,000 connectors in China, 360,000 in Europe and 89,000 in the U.S. (Figure 55). Annual new installations soared across China, Europe and the U.S., despite the pandemic, as a combination of policy support and business interest brought new momentum to the market. Europe installed112,800 connectors in 2020 (Figure 56), over five times the 17,400 connectors installed in the U.S., but only about a third of the new installations in China.

Figure 55: Cumulative global public charging connectors installed

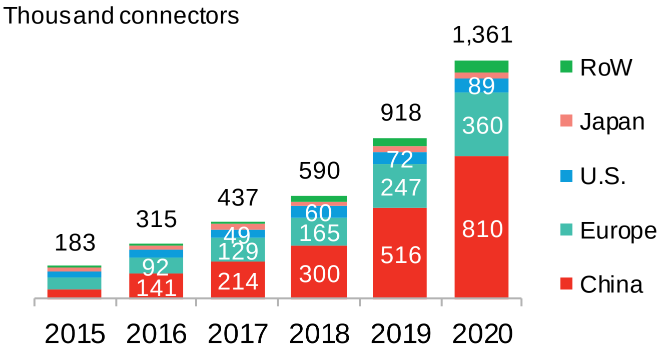
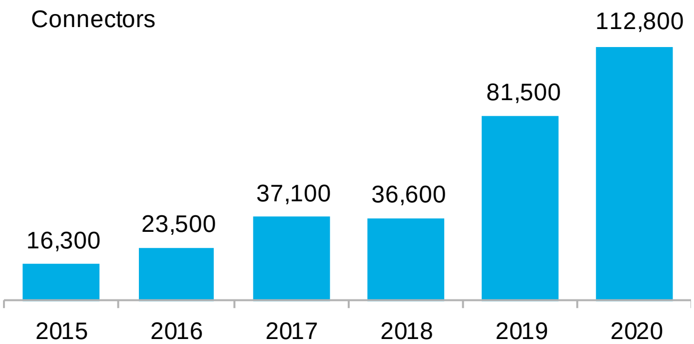


Figure 56: Annual public charging connector installations in Europe



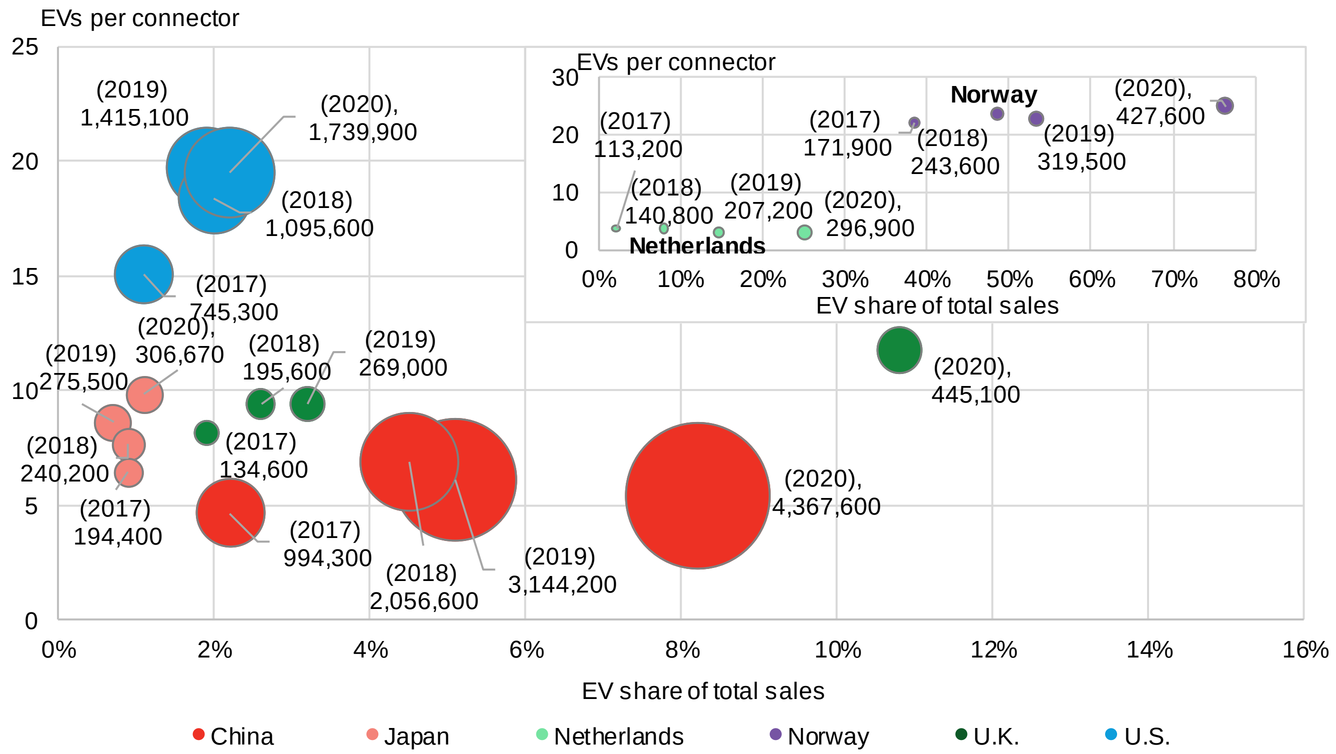
Source: BloombergNEF U.S. AFDC, Chargehub, China Electric Vehicle Charging Infrastructure Promotion Alliance, Various industry data sets. Note: Includes Tesla destination and supercharger networks even though this is semi-private.

Globally, the number of EVs per public connector stayed flat between 2019 and 2020, at 7.4 EVs per connector, showing that the growth in EV sales was matched by growth in public charging infrastructure. However, the ratio varies across countries, also in Europe. In Norway, the ratio of EVs per connector is much higher than the global average, at 25 EVs per connector. In contrast, the Netherlands has 3 EVs per connector. The differences between countries are due to a number of factors, including:

- Building stock: countries with a higher share of apartments will have a lower prevalence of home charging and are therefore more reliant on public charging.
- Public charging hardware power: countries with higher-power public infrastructure should need less connectors to charge the same number of vehicles.
- Electric vehicle stock: markets with a high number of plug-in hybrid sales will require a different blend of public charging infrastructure.

Further analysis shows that the ratio across leading EV markets has stayed consistent over the last four years (Figure 57), indicating that increasing sales of EVs act as a charging infrastructure investment signal. In the Netherlands, the ratio moved from 3.7 in 2017 to 3.0 in 2020, even though total EV sales increased 162% in that timeframe. In Norway, the ratio increased from 23 in 2019 to 25 in 2020, even as EV's share of total passenger car sales passed 70%. In the U.K., the ratio rose to 11.7 in 2020 from 9.4 in 2019. This shows slower public charging growth in the country compared to EV sales, which jumped to 11% of total sales in 2020 from 3.2% in 2019.

Figure 57: EVs per public charging connector across various regions over time



Source: BloombergNEF. Note: Bubbles indicate the size of the passenger EV fleet.

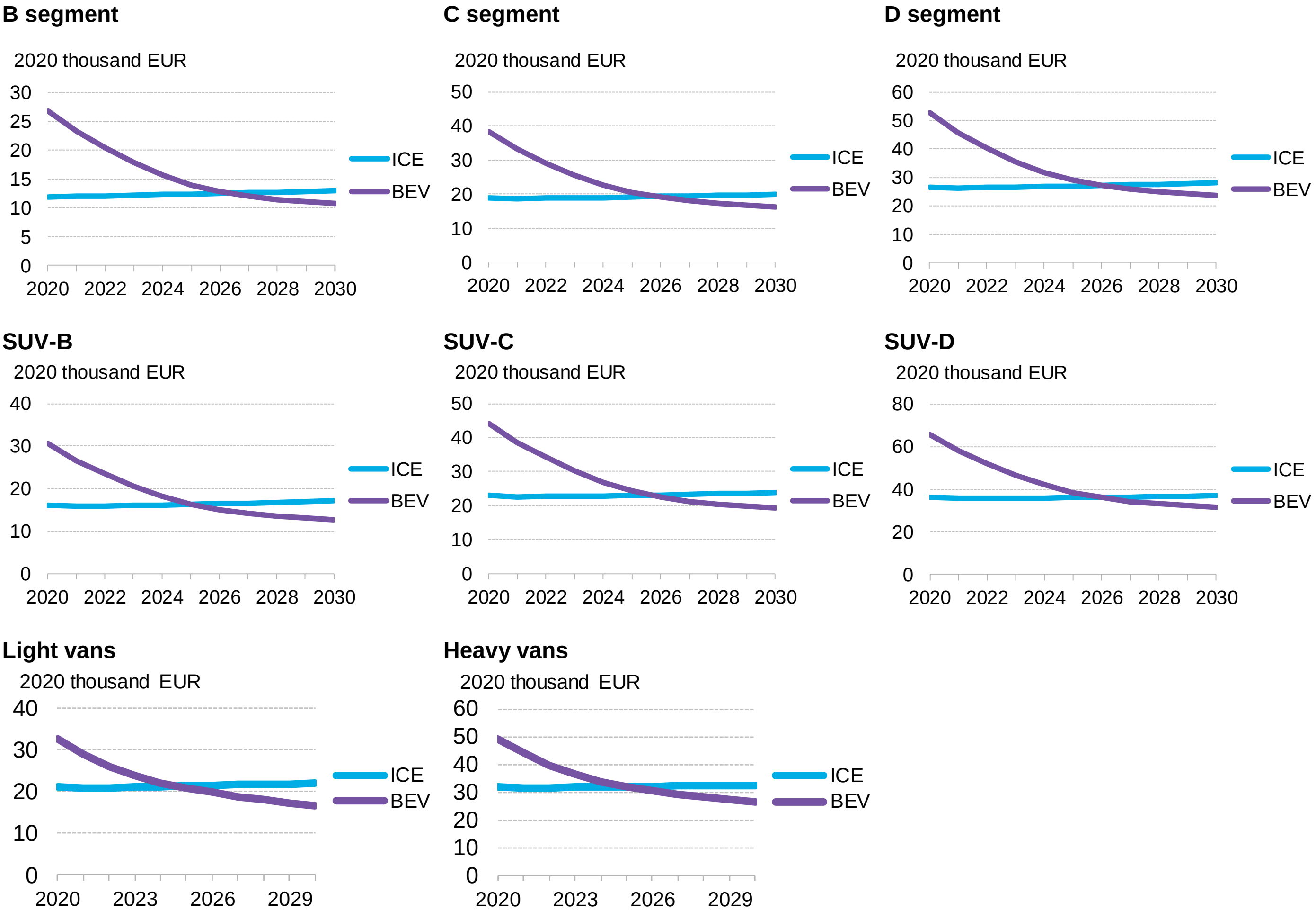
The need for charging infrastructure rollout will continue to grow. Today most EV charging takes place at home, but a robust public charging network will be needed to get to high levels of EV adoption across all buyer segments and housing types. Residents of high-rise multi-dwelling units in particular are more likely to rely on the public network than those who live in single detached homes.

We have not factored charging infrastructure spending into the BEV price parity analysis, or how a lack of public charging infrastructure could impact the adoption curves. However, BloombergNEF estimates that around 1.8 million public charging points will be needed across Europe by 2035 to support the private BEV fleet in this analysis in the base case and 2 million public charging points in the accelerated case. The total investment required for the base case public charging infrastructure requirements will be around $13.4 billion and for the accelerated case $14.6 billion. The European private EV fleet will be growing very rapidly by 2035, and the number of public charging points would need to increase further to around 2.5 million between 2035 and 2040 to continue to support this growth. This analysis does not include vans, shared vehicles or PHEVs, which may rely more heavily on public charging than private BEV vehicles.

Appendices

Appendix A. ICE and BEV pre-tax retail prices for all segments

Figure 58: Estimated pre-tax retail prices for passenger vehicles and vans



Source: BloombergNEF Note: ICE is internal combustion engine vehicle and BEV is battery electric vehicle

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Parlamentarischer Beirat
f. nachhaltige Entwicklung

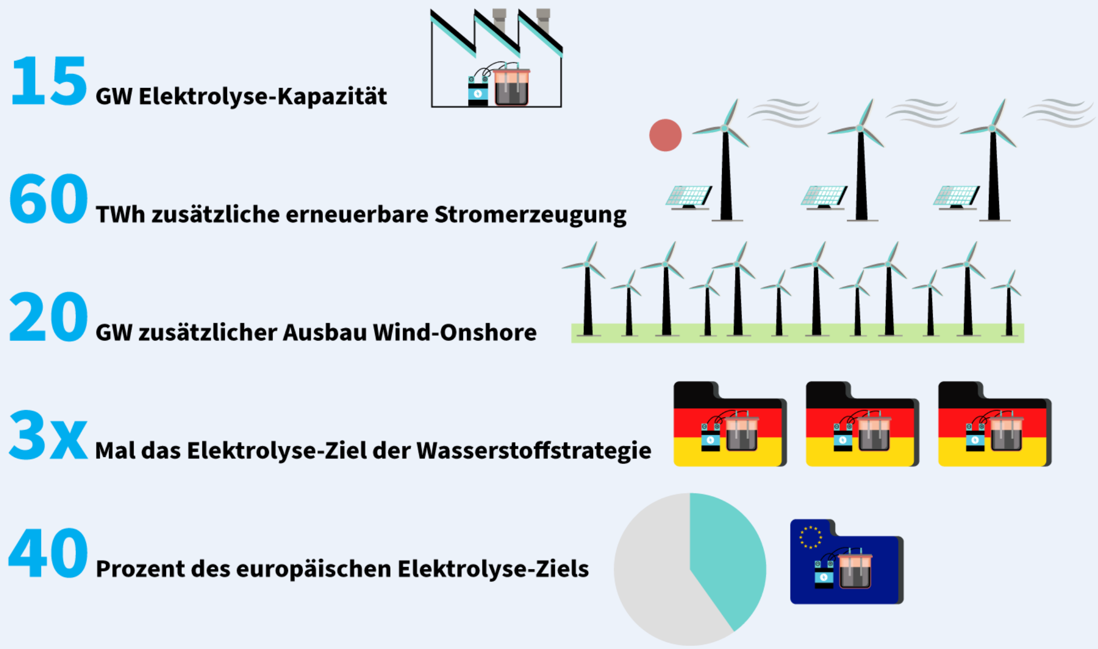
Ausschussdrucksache
19(26)117-3

Was bedeutet eine Unterquote von 5 % E-Fuels im Straßenverkehr?

Implikationen für den Ausbau von Elektrolyseuren und erneuerbaren Energieanlagen

April 2021

In einem jüngst veröffentlichten Positionspapier der CDU/CSU-Fraktion wird die Prüfung einer Unterquote für strombasierte Kraftstoffe in Höhe von 5 Prozent vorgeschlagen. Eine solche Unterquote wurde in der Vergangenheit vom Verband der Deutschen Automobilindustrie (VDA) gefordert. Transport & Environment Deutschland hat berechnet, was eine solche Unterquote für den Ausbau von Elektrolyseuren und erneuerbaren Energieanlagen in Deutschland bedeuten würde.



Um 5 Prozent Kraftstoffe, die im Straßenverkehr in Deutschland abgesetzt werden (Diesel und Benzin), durch strombasierte Kraftstoffe (E-Fuels) zu ersetzen, sind rund **15 GW Elektrolyse-Kapazität** erforderlich. Für den Betrieb dieser Elektrolyseure mit erneuerbarer Energie sind **60 TWh** Strom notwendig. Dies entspricht einer Kapazität von **20 GW Onshore-Wind**, die bis 2030 in Deutschland zusätzlich zu dem geplanten Ausbau entstehen müssten, um einen positiven Klimaeffekt dieser Kraftstoffe zu gewährleisten.

15 GW Elektrolyse ist das **Dreifache**, was in der **Nationalen Wasserstoffstrategie** bis 2030 für die deutsche Wirtschaft insgesamt vorgesehen ist (5 GW). Zugleich sind es rund **40 Prozent** des in der gesamten **Europäischen Union** bis 2030 geplanten Elektrolyse-Ausbaus (40 GW).

Mit diesen Zahlen möchten wir auf die **technische Machbarkeit** und die Implikationen für die **Dekarbonisierung anderer Sektoren** der aufgestellten Forderung hinweisen.

1. Grundlagen unserer Berechnung

Im Folgenden werden die Daten und Annahmen unserer Berechnungen im Detail vorgestellt:

Berechnung der zu ersetzenden Kraftstoffmenge	
Kraftstoffverbrauch (Diesel und Benzin) 2019	50.162 Mtoe
Annahme zum Rückgang des Kraftstoffverbrauchs aufgrund des Markthochlaufs der E-Mobilität im Jahr 2030	20 Prozent
Resultierende Annahme zum Kraftstoffverbrauch 2030	40.100 Mtoe
5 Prozent Quote basierend auf der 2030-Annahme	**2.005 Mtoe**
Wirkungsgrade und weitere technische Spezifikationen der Elektrolyse- und PtL-Anlagen	
Wirkungsgrad Elektrolyse	79 Prozent
Wirkungsgrad PtL-Anlage	72 Prozent
Volllaststunden Elektrolyse	4 000 Stunden
Gesamtanteil von Diesel und Benzin an der PtL-Produktion*	68 Prozent
Annahmen zu erneuerbarer Stromerzeugung	
Wind-Onshore in Deutschland Volllaststunden Load-Factor	 2850 0,33
Aktuell geltende Elektrolyse-GW-Ziele	
Deutschland: Nationale Wasserstoffstrategie	5 GW
EU: EU Hydrogen Strategy	40 GW in der EU

*Im Prozess der Kraftstoffherstellung in einer Raffinerie fallen verschiedene Fraktionen an (Diesel, Benzin, Kerosin, Naphtha usw.). Je nach Design der Anlage, das u. a. durch regulatorische Anreize beeinflusst werden kann, kann der Anteil verschiedener Fraktionen an dem gesamten Output variieren, zum Beispiel zugunsten eines höheren Anteils von Kerosin. Zum Zwecke der vorliegenden Berechnung wurde ein hoher Anteil von Diesel und Benzin angenommen.

2. Einordnung der Ergebnisse im Kontext der Deutschen und der Europäischen Wasserstoffstrategien

Laut der Nationalen Wasserstoffstrategie (NWS) sollen bis zum Jahr 2030 5 GW Elektrolyse-Leistung in Deutschland entstehen. Die zur Erreichung einer 5-Prozent-E-Fuels-Unterquote erforderliche Kapazität **übersteigt dieses Ziel um das Dreifache**. Sogar bei einer signifikanten Anhebung des nationalen Elektrolyse-Ziels hätte eine solche Unterquote zur Folge, dass andere Branchen und Anwendungen von der Nutzung von grünem Wasserstoff ausgeschlossen wären.

Auch die Ausbaukorridore von erneuerbaren Energieanlagen müssten entsprechend angehoben werden, um die Versorgung von Elektrolyseuren mit den hierzu notwendigen 60 TWh erneuerbaren Strom zu gewährleisten. Dies entspricht einer Kapazität von 20 GW Onshore-Wind bzw. einer **Anhebung des Ausbauziels von Onshore-Wind von heute 71 GW (EEG-Novelle 2021) auf mindestens 91 GW im Jahr 2030**. Ohne diesen zusätzlichen Ausbau kann die Nachhaltigkeit von E-Fuels nicht gewährleistet werden, mehr noch würde der zusätzliche Strombedarf bei gleich bleibendem Anteil von erneuerbaren Energien zu einer insgesamt höheren CO_2-Bilanz des Strommixes führen.

Die EU hat sich zum Ziel gesetzt, 40 GW Elektrolyse-Kapazität bis 2030 zu erreichen. 15 GW, die zur Erfüllung einer deutschen 5-Prozent-E-Fuels-Quote erforderlich sind, machen **40 Prozent des europäischen Ziels** aus. Dabei ist zu bedenken, dass auch andere Mitgliedstaaten ihre eigenen Ansprüche auf die Nutzung von grünem Wasserstoff zur Erreichung der ambitionierten Klimaschutzziele haben. Auch wenn in einem theoretischen Fall die Mobilisierung der europäischen Ressourcen in Höhe von 40 Prozent des EU-Ziels für den deutschen Kraftstoffmarkt möglich wäre, würde eine solche Strategie die Investitionen weg von den schwer zu dekarbonisierenden Sektoren umlenken und somit die Klimaschutzanstrengungen in diesen Sektoren unnötig verzögern. Zudem ist zu beachten, dass das Umlenken der Klimaschutzinvestitionen in ein auslaufendes Geschäftsmodell mit dem Verbrennungsmotor die **Transformation des Verkehrssektors stark verteuern würde**.

Häufig wird suggeriert, dass E-Fuels und Wasserstoff aus den Ländern mit besseren Voraussetzungen für die Erzeugung von erneuerbaren Energien (z. B. MENA-Region) importiert werden können[1] weshalb sie als eine Klimaschutzoption im Straßenverkehr zum Einsatz kommen sollten. Globaler Handel mit grünem Wasserstoff kann sicherlich künftig eine Rolle bei der Erreichung der Klimaneutralität in Europa sowie der Pariser Klimaziele in anderen Teilen der Welt spielen, einen bereits kurzfristig wirksamen Beitrag zum Klimaschutz bis 2030 ist dennoch nicht zu erwarten. Erstens befinden sich Projekte[2], die die Entwicklung von internationalen Wasserstofflieferketten zum Ziel haben, erst in ihrer Anlaufphase. Zweitens müssen die Rahmenbedingungen für einen solchen Handel erst geschaffen werden, vor allem der Aufbau der Transportinfrastruktur sowie die Einführung eines internationalen Zertifizierungssystems für Wasserstoff und seine Derivate.

---

[1] Z. B. Studie von Frontier Economics „Der Effizienzbegriff in der klimapolitischen Debatte zum Straßenverkehr".

[2] Z. B. deutsch-australisches Wasserstoffprojekt „HySupply", Pilotprojekt von Porsche und Siemens Energy in Chile.

3. Fazit

Die durchgeführte Kurzanalyse zeigt, dass die Einführung einer 5-Prozent-Unterquote für E-Fuels im Straßenverkehr aufgrund der enormen Anforderungen an den Ausbau von Elektrolyse-Kapazitäten und erneuerbaren Energieanlagen bis 2030 höchstwahrscheinlich nicht realisierbar ist. Eine Möglichkeit zur Erreichung einer solchen Vorgabe wäre das Umlenken von 40 Prozent der in der EU bis 2030 geplanten Elektrolyse-Kapazität sowie des zum Betrieb dieser Kapazität erforderlichen Ausbaus von erneuerbaren Energieanlagen zugunsten des deutschen Kraftstoffmarktes.

Dies macht deutlich, dass eine solche Unterquote nur auf Kosten der Bedarfe anderer Sektoren (u. a. in anderen Mitgliedstaaten) und/oder auf Kosten der Nachhaltigkeit von E-Fuels implementierbar wäre. Anreize für E-Fuels im Straßenverkehr bei gleichzeitiger Nutzungskonkurrenz von grünem Wasserstoff würde unmittelbar die Nachhaltigkeit dieser Kraftstoffe unter Druck setzen und somit den Weg für die klimaschädlichen Herstellungsarten von Wasserstoff ("blau", Strommix) bereiten. Eine Unterquote für E-Fuels im Straßenverkehr wird daher von T&E kategorisch abgelehnt.

Ohne den grünen Wasserstoff und seine Derivate wird eine vollständige CO_2-Minderung in schwer zu dekarbonisierenden Sektoren nicht möglich sein. Deshalb ist es wichtig, in den nächsten 10 Jahren die Elektrolyse- und PtL-Anlagen zu skalieren und mit der Markteinführung dieser Energieträger in der Schwerindustrie, Luft- und Schifffahrt zu beginnen. Die Investitionsentscheidungen der nächsten Jahre werden darüber entscheiden, wie gut uns diese Aufgabe gelingt. Die Fehlallokation von Ressourcen kann die Erreichung der Klimaneutralität unnötig verzögern und verteuern.

Die vorgeschlagene 5-Prozent-Quote birgt ähnlich wie andere Anreize für E-Fuels im Straßenverkehr die große Gefahr einer solchen Fehlallokation. Die Rettung eines auslaufenden Geschäftsmodells auf Kosten der CO_2-Minderung in anderen Sektoren ist eine riskante Strategie für Deutschland und Europa.

Kontakt

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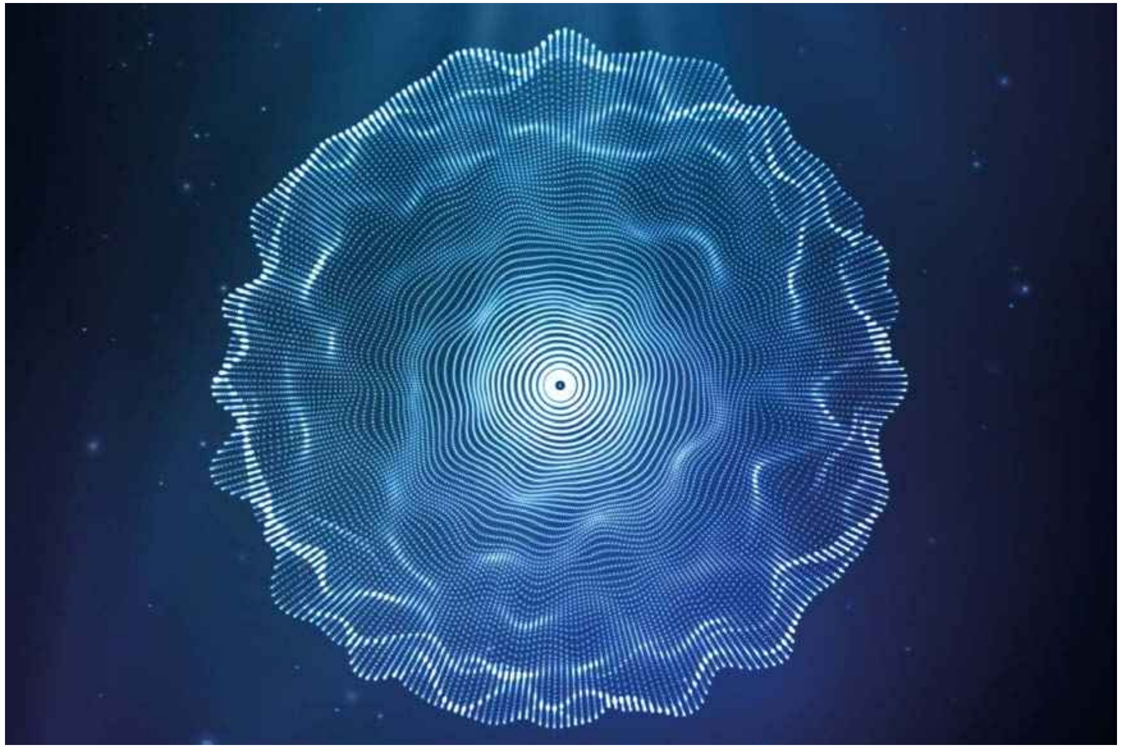
WASSERSTOFF UND SEINE DERIVATE FÜR EINE NACHHALTIGE MOBILITÄT

Deutscher Bundestag
Parlamentarischer Beirat
f. nachhaltige Entwicklung
Ausschussdrucksache
19(26)118



Prof. Christopher Hebling

- Bereichsleiter Wasserstofftechnologien
- Sprecher des Wasserstoff-Netzwerks der Fraunhofer-Gesellschaft
- Mitglied im Expertenausschuss zum Zukunftsfonds Automobilindustrie

Fraunhofer-Institut für Solare Energiesysteme, ISE

80. Sitzung des Parlamentarischen Beirates für nachhaltige Entwicklung, Berlin, 19. May 2021

Fraunhofer Strategische Forschungsfelder

Bioökonomie	Digitale Gesundheits-vorsorge	Künstliche Intelligenz	Nächste Computer Generation	Quanten Technologien	Resourcen Effizienz und Klima-technologien	Wasserstoff-technologien

- Bezahlbares Gesundheitswesen
- Energiewende vollenden
- Sicherheit und resiliente Gesellschaft
- Digitalisierte Wertschöpfungs-ketten
- Vollständige Kreislauf-wirtschaft

Fraunhofer ISE

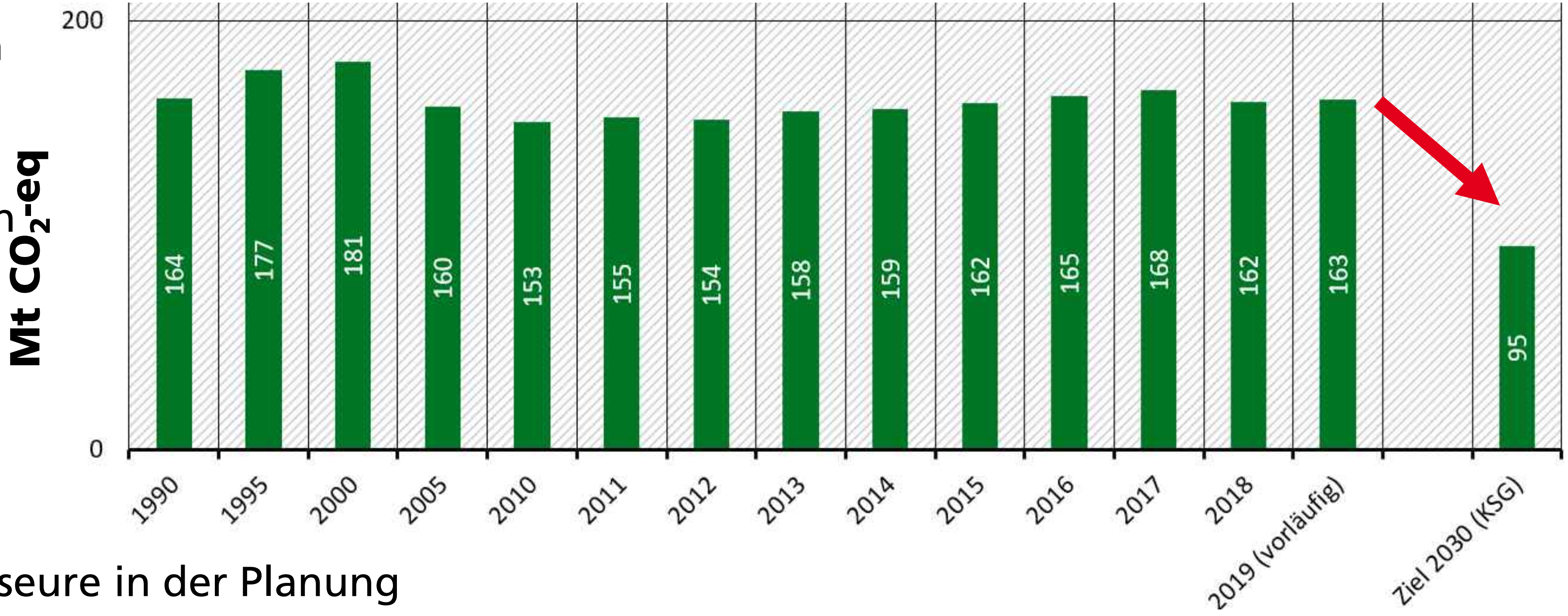
Ausgangslage

Treibhausgasemissionen im Mobilitätssektor in Deutschland seit 1990

- Das Bundesverfassungsgerichtsurteil zum Bundes-Klimaschutzgesetz führt zu massiver Verschärfung der benötigten Klimaschutzmaßnahmen inklusive dem Zeitpunkt deren Implementierung
- Zusätzlich: Verschärfung der Lokalemissionen durch Euro 7 (2025) bzw. CARB/EPA (2024)

Weiterhin:

- 189 Staaten ratifizierten das Pariser Abkommen
- > 75 Staaten streben Klimaneutralität 2050 an
- > 30 Staaten haben nationale H_2-Strategien
- $ 300 Mrd. für H_2-Prod., Transport, Nutzung in Entwicklung bis 2030
- Aktuell 17 GW Elektrolyseure in der Planung



Source: UBA 2020

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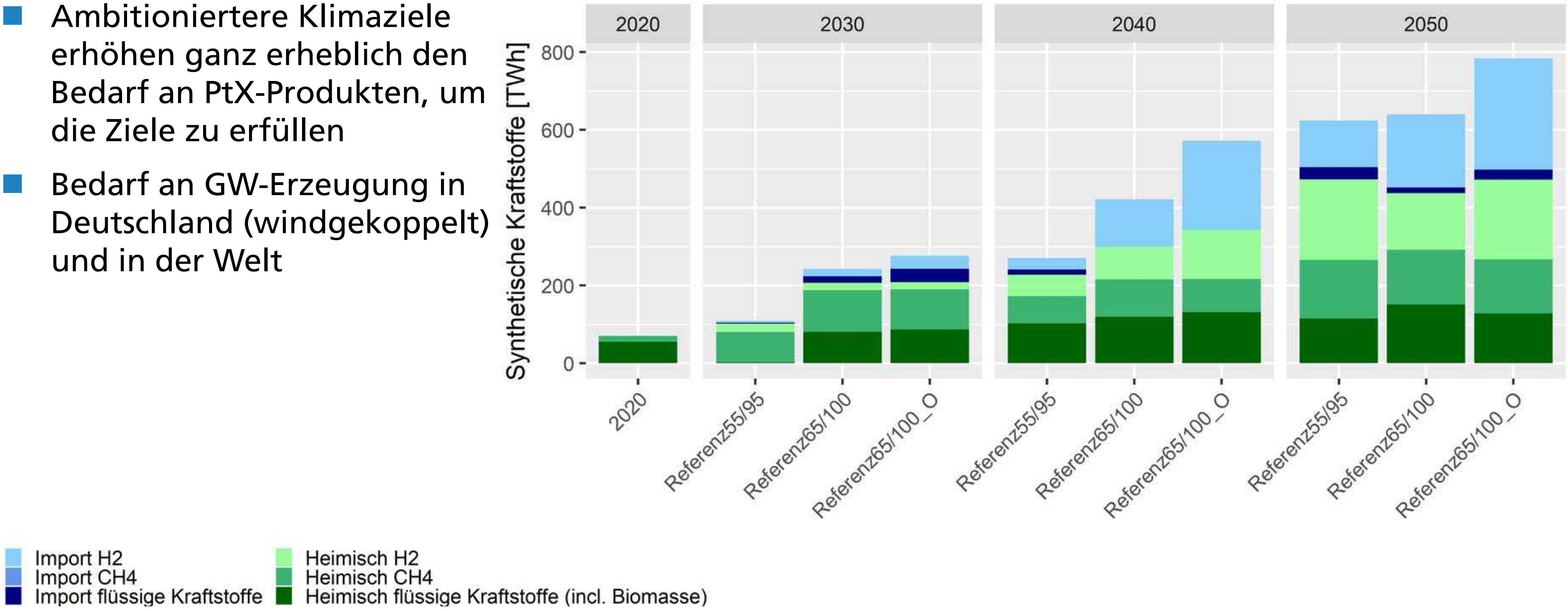
Szenarien für die nationale und internationale Produktion von PtX-Produkten

REMOD-Energiesystemsimulationen des Fraunhofer ISE

- Ambitioniertere Klimaziele erhöhen ganz erheblich den Bedarf an PtX-Produkten, um die Ziele zu erfüllen
- Bedarf an GW-Erzeugung in Deutschland (windgekoppelt) und in der Welt



Fraunhofer ISE

Meta-Studie Wasserstoff für den Nationalen Wasserstoffrat

Überblick über EU-Studien

Level	Abbreviation	Study
EU	EC 2020	COMMISSION STAFF WORKING DOCUMENT - IMPACT ASSESSMENT
	JRC 2020	Towards net-zero emissions in the EU energy system by 2050
	EC 2019	Industrial Innovation – Pathways to deep decarbonisation of industry Part 2
	EC 2018	A Clean Planet for all

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Meta-Studie Wasserstoff für den nationalen Wasserstoffrat

Überblick über betrachtete nationalen Studien, nicht älter als 2018

Level

National

Abbreviation	Study
BDI 2018	Klimapfade für Deutschland
dena 2018	Dena Leitstudie – Integrierte Energiewende
Agora 2020	Klimaneutrales Deutschland
UBA 2019	Wege in eine ressourcenschonende Treibhausgasneutralität
BMWi 2021	Leitstudie – Langfristszenarien und Strategien für den Ausbau der Erneuerbaren
ISE 2020	Wege zu einem klimaneutralen Energiesystem – Die Deutsche Energiewende im Kontext gesellschaftlicher Verhaltensweisen
Jülich 2019	WEGE FÜR DIE ENERGIEWENDE – Kosteneffiziente und klimagerechte Transformationsstrategie
NRW 2019	Wasserstoff Nordrhein-Westfalen

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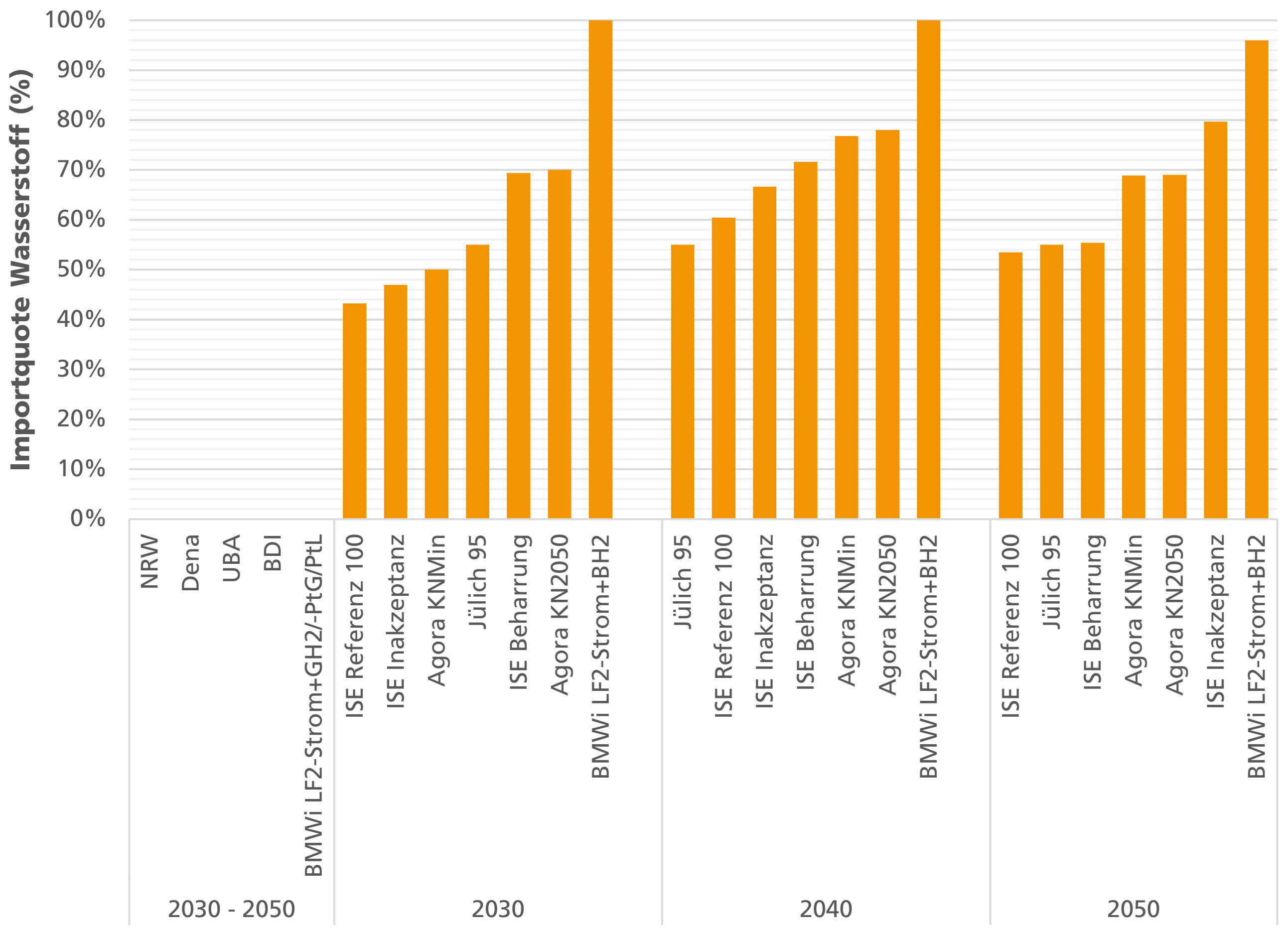
Importquoten Wasserstoff

- Importquoten Wasserstoff
  - Bandbreite 2030: 43 bis 70 %
  - Bandbreite 2040: 55 bis 78 %
  - Bandbreite 2050: 53 bis 80 %
  - Trend: Höhepunkt der Importquote in 2040, danach wieder leichter Rückgang
- UBA, Dena, BDI und BMWi LF2-PtG/PtL gehen von einer Importquote von (fast) 0% aus
  - Größere Bedeutung von Syntheseprodukten
- BMWi LF2-Strom teilt sich in zwei Angebotsszenarien, in denen Wasserstoff nicht (GH2) bzw. fast ausschließlich (BH2) importiert wird
- NRW betrachtet Importe nur in der Sensitivitätsanalyse



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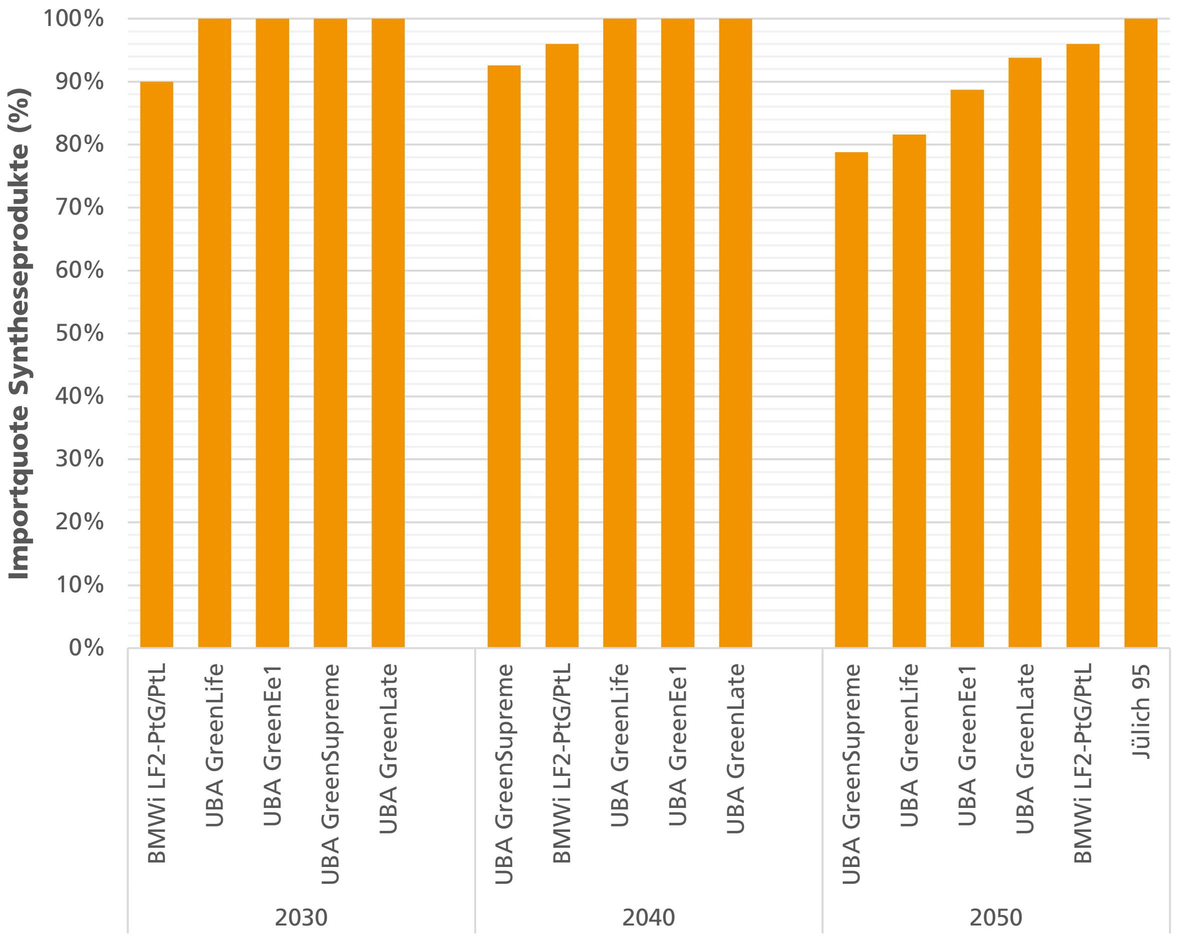
Importquoten Syntheseprodukte

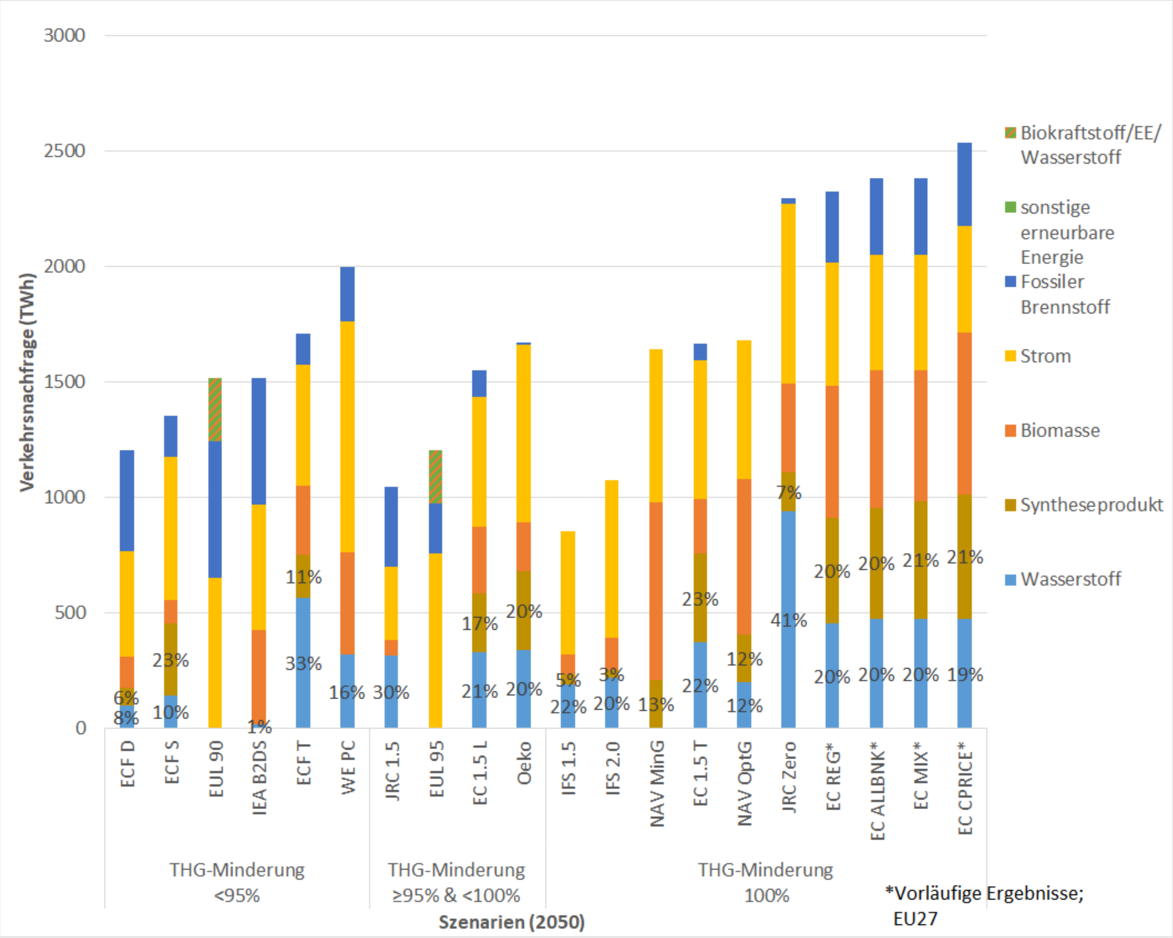
- Importquoten Syntheseprodukte
  - Bandbreite 2030: 90 bis 100 %
  - Bandbreite 2040: 93 bis 100 %
  - Bandbreite 2050: 79 bis 100 %
  - Trend: generell sehr hohe Importquoten für Syntheseprodukte, ab 2050 erschließt sich in den UBA-Szenarien z.T. auch ein Heimmarkt
- Dena: Importquote Wasserstoff- und Syntheseprodukte:
  - 2040: 22 % - 23 %
  - 2050: 74 % (EL95) – 82 % (TM95)
- BDI: Importquote Wasserstoff- und Syntheseprodukte
  - 2050: 89%
- Setzung Agora 2020: Importquote Syntheseprodukte = 100 % (2030-2050)



2050: Verkehr – Wasserstoff und Syntheseprodukt spielen in der Verkehrsnachfrage eine große Rolle

- Gesamte Verkehrsnachfrage zeigt große Abweichungen
  - Überwiegender Teil von den Szenarien enthält nur 60 % der Sektornachfrage (bzw. exkl. internationale Flüge und Schiffe)
- Bei 100 % THG-Minderung:
  - Reine Wasserstoffnachfrage eher bei ca. 20 %
  - Syntheseproduktnachfrage eher um 20 % (bei Einbezug int. Flug- und Schifffahrt)

Endenergienachfrage im Verkehrssektor EU 2050



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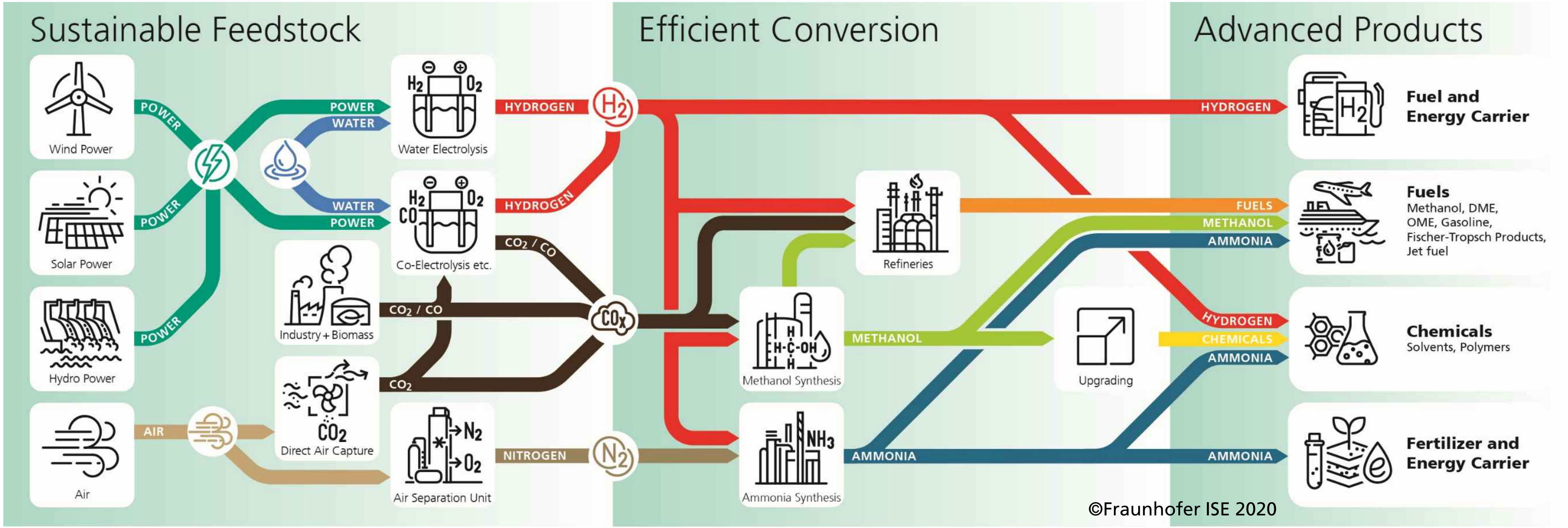
PtX-Produkte für die Mobilität, den Energiesektor und die Industrie



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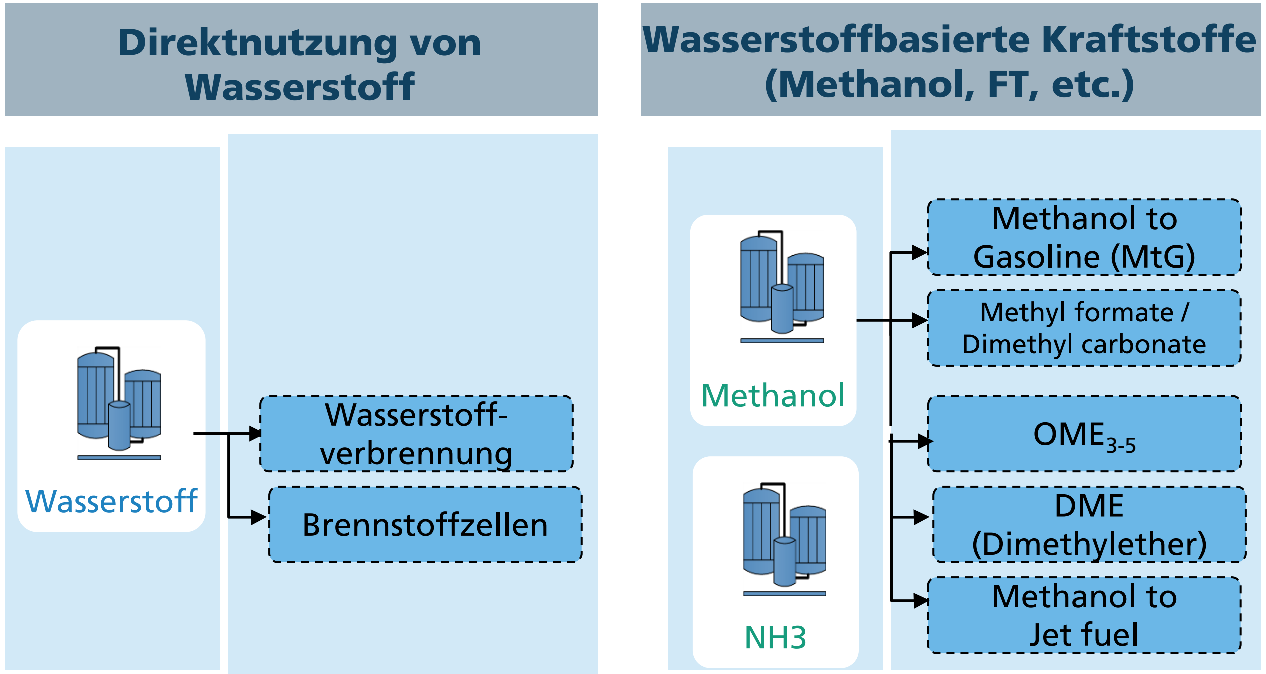
Erneuerbare Kraftstoffe

Wasserstoff und wasserstoffbasierte Derivate (MeOH, NH_3)

Kriterien*

- CO_2 "quasi"-Neutralität über gesamten Lebensdauerzyklus
- Nachhaltigkeit in Bezug auf unbegrenzte Verfügbarkeit
- Minimaler ökologischer Fußabdruck
- Ökonomische Effizienz
- Bestmögliche Integration in bestehende Technologien und Infrastrukturen (drop-in)



- Evolutionäre und revolutionäre Technologien benötigt
- Lebenszyklusanalysen verschiedener Antriebstechnologien
- Globale Perspektive ist von entscheidender Wichtigkeit

* Gaukel, K. et al. (2016) 37. Internationales Wiener Motorensymposium, Conference Proceedings, 193-223.

Mehr als 30 nationale Wasserstoff-Roadmaps

Antreiber für Wasserstoff

-Environment (Paris Agreement)
-Economy, Industry, Export
-Flexible Energy System
-Air Quality

-Economy, Industry
-Import-Independence
-Air Quality
-Environment

-Environment (RED II)
-Industry
-Export
-Economy and Industry
-H2-Production
-Environment

-Economy and Industry

-Industriepolitik
-CO2-Neutralität
-THG-Reduzierung
-Flexibles Energiesystem

-Environment
-Economic Growth

-Economy and Industry
-Self Sufficiency
-GHG-Reduction
-Air Quality

-Prosperity, Growth
-Industry
-Air Quality
-CO2-Reduction
-Supply Security
-Export

-Environment
-Economy and Industry
-Efficiency
-Import

-Economic Growth
-Import (North Africa)
-European Green Deal (GHG-Reduction, Climate Neutrality)
-Supply Security

-Economic Growth
-Export
-Independence / Self Sufficiency
-Environment
-Supply Security in isolated areas

-Air Quality
-Supply Security
-GHG-Reduction
-Industry

MENA
-Economic Growth
-Export (Europe)
-Social Stability

-Industry
-Export
-Green Mining

-Industry
-PGM-Processing

-Economic Growth
-Export
-Import-Independence
-Health
-CO2-Reduction
-Supply Security

https://de.wikipedia.org/wiki/Datei:BlankMap-World_gray.svg

Effizienz von Batteriefahrzeugen und Fahrzeugen mit Verbrennungsmotor

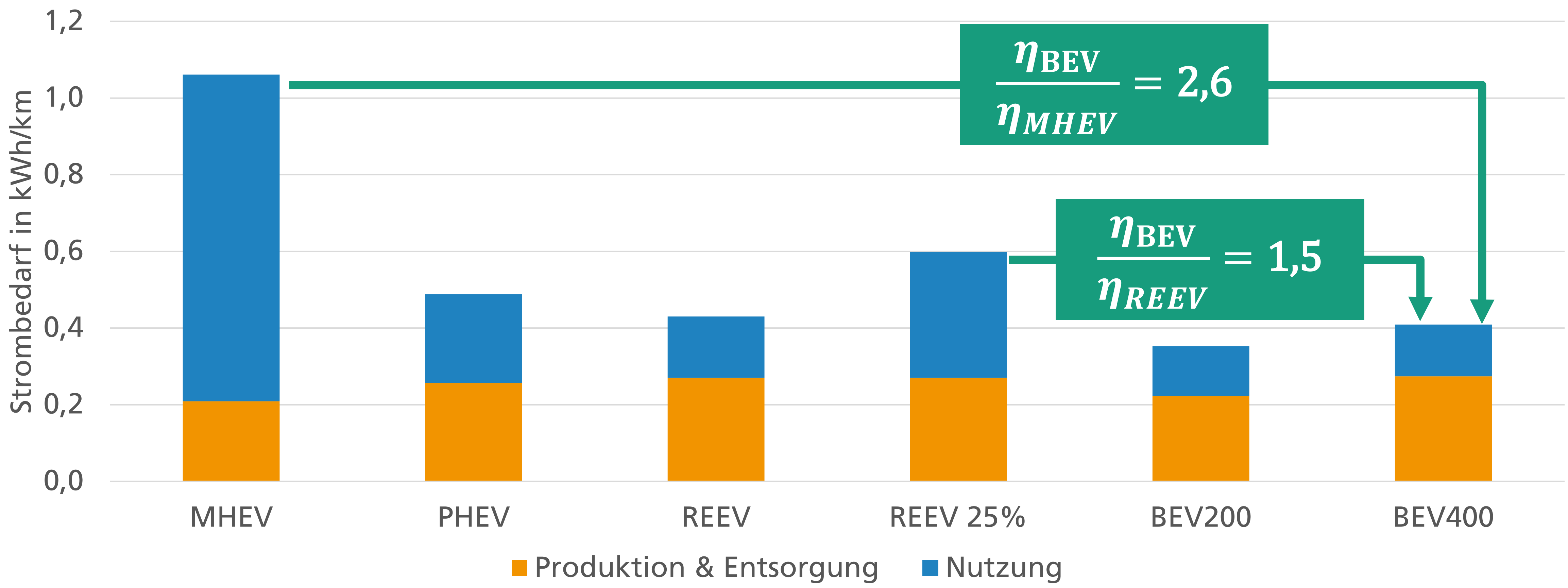
- **Aktuelle Effizienzdebatte häufig verkürzt:**
  - Batteriefahrzeug (BEV) vs. Fahrzeug mit Verbrennungsmotor (ICEV)
  - Hybridfahrzeug (HEV) wird zumeist nicht betrachtet
  - Nur Nutzungsphase wird berücksichtigt, ohne Herstellung und Recycling

$$\frac{\eta_{\mathrm{BEV}}}{\eta_{\mathrm{ICEV}}} = 5\text{–}6$$

- **Unser Ansatz:**
  - Strombedarf über gesamten Lebenszyklus (Herstellung, Nutzung und Entsorgung)
    - Herstellung: Materialien basieren auf grünem Strom (z.B. H_2-basierter Stahl)
    - Nutzung: Kraftstoffe aus Grünstrom (e-fuel)
  - Vergleich für BEV und HEV:
    C-segment in 2025+ (Daten aus [1])
    - Mild hybrid electric vehicle (MHEV)
    - Plug-in hybrid electric vehicle (PHEV)
    - Range extender electric vehicle (REEV)
    - Battery electric vehicle (BEV)

[1] Huss et al., JEC Tank-to-Wheel report v5: Passenger cars **2020**, http://dx.doi.org/10.2760/557004

Strombedarf für die Herstellung, Nutzung und Entsorgung der Fahrzeuge



Kraftstoff:	e-fuel	e-fuel + Strom	e-fuel + Strom	e-fuel + Strom	Strom	Strom

PHEV und REEV: e-fuel-Bedarf nach WLTP

REEV 25%: e-fuel wird für 25% der Fahrstrecke genutzt

Laufleistung: 200.000 km
Infrastruktur nicht berücksichtigt
Kein Second-Life berücksichtigt

MHEV: Mild hybrid electric vehicle
PHEV: Plug-in hybrid electric vehicle
REEV: Range extender electric vehicle

BEVXXX: Battery electric vehicle mit Reichweite in km

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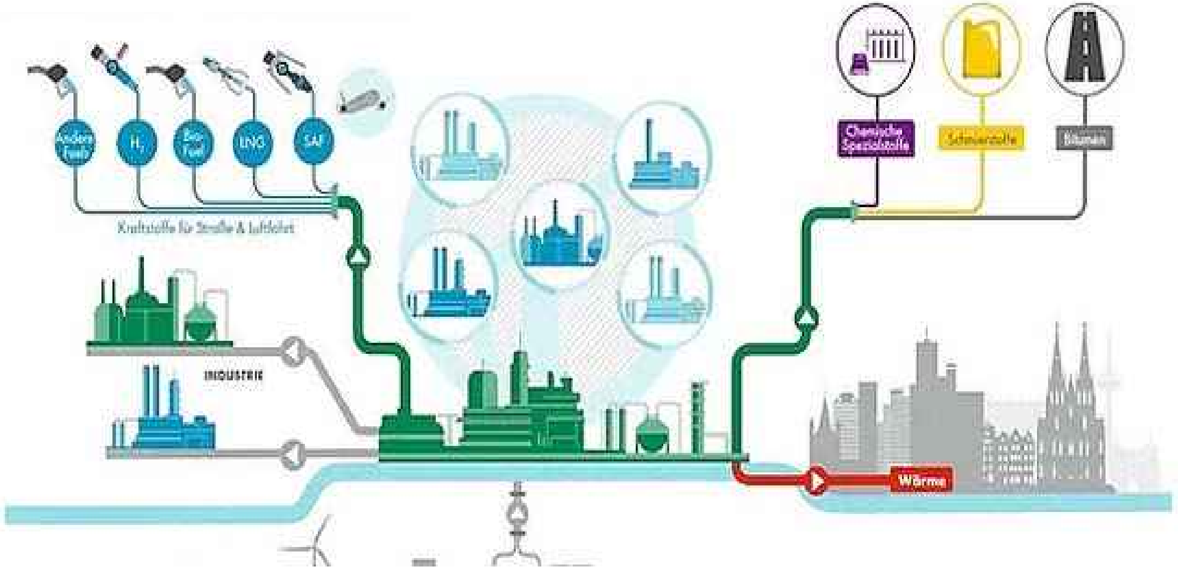
Shell: Synthetisches Kerosin – Jet Fuels

Quote bei Flugkraftstoffen: 0,5% PtL-Kerosin bis 2026, 2% bis 2030

- Herstellung nachhaltiger Flugkraftstoffe geplant
  - Bio-PtL-Anlage
  - PEM-Wasserstoff-Elektrolyse-Anlage
    - Aktuell 10 Megawatt
    - Zusätzlich 100 Megawatt
    - Kapazität 2025 zunächst 100.000 t Kerosin pro Jahr



https://www.shell.de/ueber-uns/die-marke-shell.html

https://www.shell.de/ueber-uns/projects-and-sites/shell-rheinland-refinery/aktuelles/shell-will-synthetisches-kerosin-in-rheinland-raffinerie-produzieren.html

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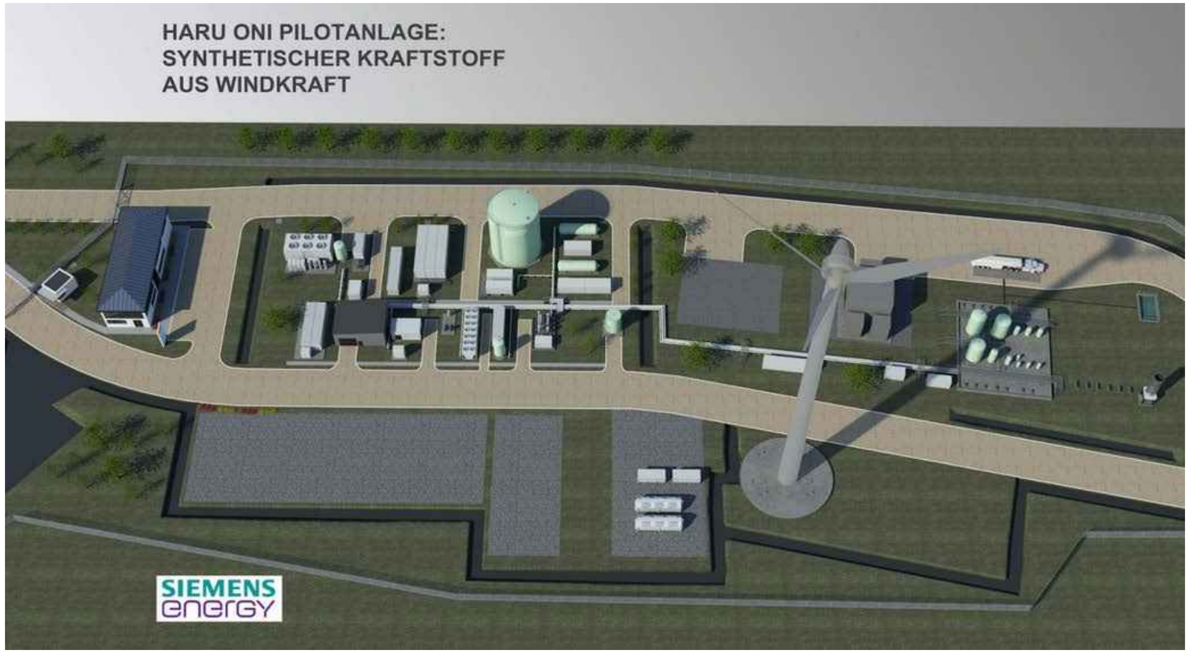
Porsche und Siemens Energy

E-Fuels in Chile

- Weltweit erste integrierte Großanlage zur Herstellung synthetischer, klimaneutraler Kraftstoffe
  - 2022: 130.000 Liter E-Fuels
  - 2024: 55 Millionen Liter E-Fuels
  - 2026: 550 Millionen Liter E-Fuels basierend auf Methanol und Methanol-to-Gasoline



- Individualverkehr in Deutschland (Quelle: KBA)
  - Durchschnittliches PKW-Alter in Deutschland: 2019: 9,3 Jahre (Europa 15-17 Jahre)
  - PKW-Bestand in Deutschland: 2021: 48,3 Millionen
  - Neuzulassungen von Elektro-PkW (BEV) in Deutschland: 2020: 194.200

https://newsroom.porsche.com/de/2020/unternehmen/porsche-siemens-energy-pilotprojekt-chile-forschung-entwicklung-synthetische-kraftstoffe-efuels-23020.html

Maersk: „Methanol und Ammoniak werden eine bedeutende Rolle spielen“

Maersk Nachhaltigkeitsbericht 2020

- Verfügbarkeit von ‚net-zero‘-Technologien
- Keine Verwendung von ‚Übergangskraftstoffen‘ (wie LNG), sondern direkter Übergang zu vollständigen ‚net-zero‘-Kraftstoffen
- Klimaneutrales Schiff 2023 betrieben mit CO_2-neutralem Methanol
- Entwicklung eines Dual-Fuel Motors für Ammoniak

„Continued research on priority future fuels (biodiesel, methanol, lignin fuels and ammonia) confirming that net-zero technologies are available

MAERSK

https://www.maersk.com/news/articles/2021/02/23/maersk-backs-plan-to-build-europe-largest-green-ammonia-facility

Der globale Handel von Erneuerbaren-Energien-Produkten basierend auf Wasserstoff beginnt jetzt

- Wir werden die Energiewende im Sinne der Klimaneutralität nur dann erfolgreich umsetzen, wenn wir den **grundlegend neuen Charakter des neuen Energiesystems** verstehen
- **Fossile Energie** inkl. deren inhärenten Eigenschaft der Speicherung **muss in allen Sektoren vollständig ersetzt werden**
- **Wasserstoff und wasserstoffbasierte Kraftstoffe** ermöglichen neben batterieelektrischen Antrieben eine **nachhaltige Mobilität** in Brennstoffzellensystemen sowie in verbrennungsmotorischen Antrieben
- **Nationale Politik muss klare Pfade und Ziele für Klimaneutralität** vorgeben und dabei Well-to-Wheel-Betrachtungen zugrunde legen (Unterquoten für nachhaltige Energieträger in allen Sektoren)
- Die Bedeutung von **grünen Elektronen und grünen Molekülen** steigt gleichermaßen
- **Die Transformation ist kosteneffizient** sobald CO_2-Emissionen entsprechend verteuert werden
- **Internationale Betrachtung der Transformation** ist Voraussetzung für eine schnelle Umsetzun für **langfristige Handelsbeziehungen und sichere Investitionsumgebungen**

Vielen Dank für Ihre Aufmerksamkeit

Foto © Fraunhofer ISE

Fraunhofer Institute for Solar Energy Systems ISE, www.ise.fraunhofer.de

Prof. Christopher Hebling, christopher.hebling@ise.fraunhofer.de

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Anlage 6

Sustainable Energy & Fuels

PAPER

View Article Online
View Journal | View Issue

Check for updates

Cite this: *Sustainable Energy Fuels*, 2018, **2**, 1244

Economics & carbon dioxide avoidance cost of methanol production based on renewable hydrogen and recycled carbon dioxide – power-to-methanol

Christoph Hank,[ab] Svenja Gelpke,[a] Andrea Schnabl,†[a] Robin J. White,*[a] Johannes Full,[a] Nikolai Wiebe,[a] Tom Smolinka,[a] Achim Schaadt,[a] Hans-Martin Henning[a] and Christopher Hebling[a]

The synthesis of sustainable methanol based on renewable electricity generation, sustainable hydrogen (H_2) and recycled carbon dioxide (CO_2) represents an interesting sustainable solution to integrated renewable energy storage and platform chemical production. However, the business case for this electricity based product (denoted hereafter as eMeOH) under current market conditions (*e.g. vs.* conventional fossil methanol (fMeOH) production cost) and the appropriate implementation scenarios to increase platform attractiveness and adoption have to be highlighted. The aim of the following study was to perform a dynamic simulation and calculation of the cost of eMeOH production (where electricity is generated at a wind park in Germany), with comparison made to grid connected scenarios. Consideration of these scenarios is made with particular respect to the German energy market and potential for the reduction in fees/taxes (*i.e.* for electrolyser systems). This evaluation and indeed the results can be viewed in light of European Union efforts to support the implementation of such technologies. In this context, CO_2 is sourced from EU relevant sources, namely a biogas or ammonia plant, the latter profiting from the resulting credit arising from CO_2 certificate trading. Variation in electricity cost and the CO_2 certificate price (in the presented sensitivity study) demonstrate a high cost reduction potential. Under the energy market conditions of Germany it is found that eMeOH production costs vary between €608 and 1453 per tonne based on a purely grid driven scenario, whilst a purely wind park supplied scenario results in €1028–1067 per tonne. The reported results indicate that the eMeOH production cost in Germany is still above the present (although variable) market price, with the economical evaluation indicating that electrolyser and H_2 storage represent the lion share of investment and operational cost. Substitution of fMeOH results in CO_2 avoidance costs between €365 and 430 per tonne of CO_{2eq} avoided for green methanol produced in Germany. The presented assessment indicates that the eMeOH production cost in Germany will reach market parity in *ca.* 2030–2035 with the price for the avoidance of CO_{2eq} turning from a cost to a benefit at around the same time. Optimistically, the cost is predominantly influenced by rapidly reducing renewable electricity costs as is already the case in South American and Arabic countries offering the potential for methanol production at a cost of <€500 per tonne.

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DOI: 10.1039/c8se00032h

rsc.li/sustainable-energy

Introduction

With the steadily increasing contribution of renewable energy (RE) to the electrical grid, efficient and economic solutions to fluctuating energy supply storage are currently required. For example, the European Union (EU) aspires to reach a contribution of renewables to primary energy supply >80% by 2050.[1–3] Currently storage at the TWh level is needed to avoid curtailing of RE power output (Germany: 4.7 TWh in 2015; 3.7 TWh in 2016)[4] during periods of high supply from solar and wind in combination with the continuous operation of large scale fossil and nuclear power plants. Stationary storage technologies need to provide large capacities whilst simultaneously being efficient and economically attractive. The conversion of electrical into chemical energy is one solution in this context that can also provide a route to clean synthetic fuels, potentially resulting in a reduction of greenhouse gas (GHG) emissions in the mobility sector. Future mobility, besides battery and fuel

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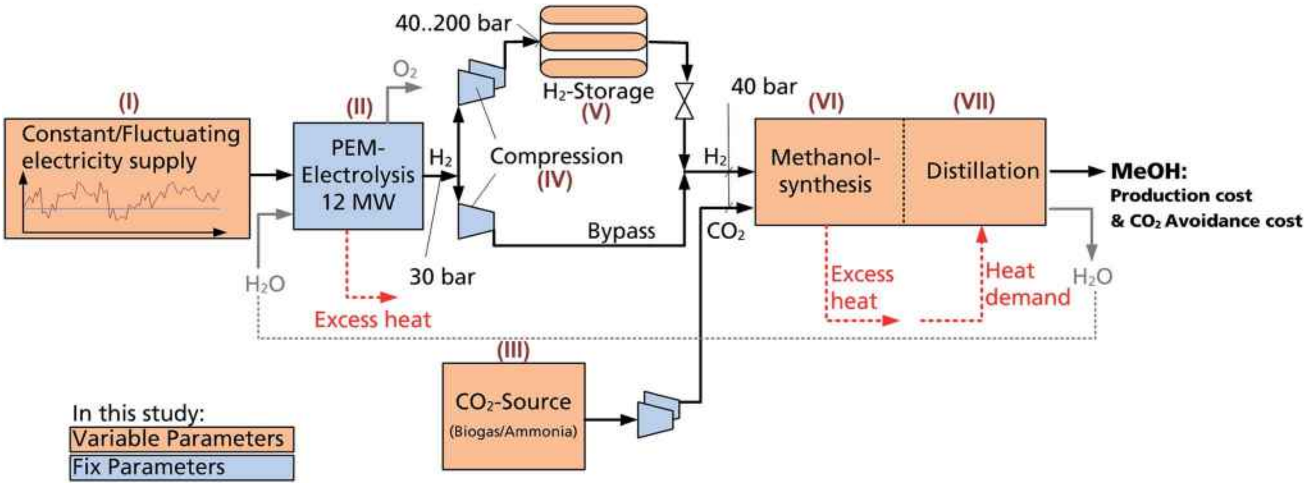


Fig. 1 The production of methanol based on renewable energy, water electrolysis and recycled carbon dioxide, commonly referred to as the "Power-to-Liquid" (PtL) process chain.

cell electric vehicles for private transport, will also be dependent on liquid fuels with energy densities suitable for heavy road freight, aviation and shipping. It would be an extremely attractive proposition if this could be achieved whilst generating suitable sustainable platform chemicals for the chemical industry and the decoupling of energy production from energy use.[5,6] Such a scheme, if based on the conversion of CO_2 will contribute to GHG emission reduction targets established through a number of national and international agreements (*e.g.* COP21).[7]

There has been much interest in the literature and at the industrial level regarding the interface between RE storage and chemical/fuel production schemes such as Carbon Capture & Utilisation (CCU) and Emissions-to-Liquids.[8] Currently in Germany, this concept is generally referred to as "Power-to-X" (PtX). X equals gas (H_2 or CH_4 – Power-to-Gas (PtG)), chemicals and liquid energy carriers (*e.g.* MeOH, Fischer–Tropsch diesel – Power-to-Liquid (PtL)). Regarding PtL, this scheme is based on the recycling of CO_2 from industrial exhaust gases or biomass plants and its hydrogenation (with H_2 produced from RE powered H_2O electrolysis) to produce long lasting chemical molecules (Fig. 1). Taking MeOH as the desired liquid product, this C1 alcohol offers numerous potential benefits:[9]

(1) An industrially established synthesis under moderate conditions such as $T < 270$ °C and $p < 80$ bar.

(2) A relatively high energy density (at ambient conditions; 16.9 MJ L^{-1}) and suitability as a storage molecule for RE (*i.e. via* 12.6 wt% (H_2)).

(3) A highly versatile platform molecule (*e.g.* olefins and acetic acid) for higher fuel production.[6,10]

(4) High volume, existing market (*ca.* 75 Mt a^{-1}; 2016) and a high ratio of market price to production cost in the case of conventional fossil production.[11]

However, the extremely low price of CH_4 (the main basis for current industrial MeOH production *via* reforming and syngas conversion[6]) makes adoption and market entry somewhat difficult for PtL.[12]

The option to recycle CO_2 is attractive as it could reduce industrial costs related to CO_2-certification, whilst holistically elevating CO_2 from a liability to a potential commercial asset.[5] It is important to note that currently the capture of industrial CO_2 and its utilisation (CCU) in chemical processes is not included in the EU Emission Trading System (EU ETS)‡ and, for this reason, does not lead to CO_2 certificate savings (*i.e.* not as for Carbon Capture and Storage (CCS)).[12,13] For the current energy system, the regulatory context is extremely important to support the economical implementation of CCU.[13–15] In January 2017 the European Court of Justice pronounced that in the case of CCU the transferred CO_2 is not to be seen as an emission, as it is not released into the atmosphere.[16,17] Hereby the emitter (*i.e.* a lime producing company implementing CCU for the production of precipitated calcium carbonate) is not obliged to purchase CO_2 certificates. In this ruling, the court annulled the second sentence of Article 49(1) of the monitoring regulation with reference to the existence of sufficient means of monitoring for the avoidance of feared CO_2 loopholes. This case is foreseen as a critical legal precedent for any CCU project which, after careful assessment of its CO_2 mitigation potential, is found to result in reduced CO_2 emissions. Therefore a comprehensive LCA is mandatory. Therefore, in this study it is assumed that imminent legislation will consider CCU as a part of the EU ETS market resulting in a credit due to the saving of CO_2 certificates. For any large scale implementation of CO_2 converting PtL processes it is important to shift focus towards biomass based CO_2 sources. Only these (besides the still cost intensive direct air capture methods) enable the recycling of CO_2 from distributed emitters. For the following economic evaluation we consider an

‡ Annex I of the EU Directive 2003/87/EC underlines that "under the EU ETS rules for any other transfer" than in the case of long-term geological storage "of CO_2 out of the installation, no subtraction of CO_2 from the installation's emissions is allowed".

industrial/fossil and a biogenic source of CO_2, namely an ammonia and a biogas plant.

Regarding the synthesis of fossil based methanol (denoted hereafter as fMeOH), three key stoichiometric equations are important (eqn (1)–(3)). The reforming and gas cleaning involved in the syngas preparation give rise to high specific CO_2 equivalent emissions. These range from 0.50 to 0.77 $t(CO_{2eq})\ t(fMeOH)^{-1}$, ref. 18 and 19 respectively, including direct specific CO_2 emissions of 0.24 $t(CO_{2dir})\ t(fMeOH)^{-1}$.[20] These emissions are coupled with a very high environmental impact as a consequence of fossil fuel exploration and processing.[21] Positively, the synthesis of electricity based methanol (denoted hereafter as eMeOH) based on the direct hydrogenation of a pure CO_2 feed is also known (eqn (1)).[22,23] According to the equilibrium reaction, the production of 1 metric tonne of MeOH (CH_3OH) requires 1.370 kg(CO_2) and 188 kg(H_2) are converted (producing 558 kg(H_2O) as a side product) (N.B. this value ignores CO_2 and H_2 consumption *via* the Reverse Water Gas Shift reaction (eqn (3)) which becomes increasingly favoured with rising reaction temperature). This equilibrium reaction occurs under exothermal reaction conditions and as a consequence is favoured at low T and because the volume reducing reaction requires high p. Efficient compression of the feed stream(s) as well as integration of the exothermal reaction heat are important factors determining the overall process efficiency.

$$CO_2 + 3H_2 \rightleftharpoons CH_3OH + H_2O,\ \Delta H_{R(298\ K,50\ bar)} = -40.9\ kJ\ mol^{-1} \quad (1)$$

$$CO + 2H_2 \rightleftharpoons CH_3OH,\ \Delta H_{R(298\ K,50\ bar)} = -90.7\ kJ\ mol^{-1} \quad (2)$$

$$CO_2 + H_2 \rightleftharpoons CO + H_2O,\ \Delta H_{R(298\ K,50\ bar)} = +42.0\ kJ\ mol^{-1} \quad (3)$$

The commercial demonstration of PtL is exemplified by the George Olah Renewable Methanol Plant (Carbon Recycling International, Iceland), operating at 5 million litres per year production. Plant operation here is based on a very low electricity cost due to inexpensive renewable geothermal power and associated low cost H_2/CO_2 sourcing.[24]

One significant distinction and possible advantage of developing CH_3OH production based on direct CO_2 hydrogenation is the avoidance of the cost intensive syngas production step (*e.g.* CH_4 reforming at T > 700 °C). It typically accounts for *ca.* 60% of total plant investment.[22] Whilst replacement of syngas production with CO_2 and H_2 sources can be relatively capital intensive, depending on the overall process conditions, investment in such a scheme can result in a "multi-benefit" system: MeOH production, recycling of CO_2 emissions, system services for the electrical power grid and indirect avoidance of fossil CO_2 emissions. In this regard, a number of recent reports have sought to evaluate the cost-effectiveness of PtL, focusing predominantly on evaluation of eMeOH synthesis with little consideration given to the preceding process steps in the process chain.[3,11,25–34] Therefore, it is the aim of the following work to investigate different electricity and CO_2 purchase options, the fundamental influence of total and partially dynamic system operation and, in turn, the impact on eMeOH production cost, H_2 storage requirements and associated investment costs. Furthermore, a complementary parametric sensitivity study is presented, highlighting the most important factors concerning eMeOH production cost (*e.g.* in a future RE system). Concerning the environmental impacts of PtL-schemes, the economic evaluation presented is concluded with the CO_2 avoidance cost – *i.e.* an important key performance indicator when evaluating technologies for CO_2 emission mitigation.

Power-to-liquid – MeOH production: a brief process description

The PtL scheme for eMeOH production, denoted hereafter as Power-to-Methanol (PtM), can be divided into six primary process steps (Fig. 1):

(I) Electricity as the main power source for the process is generated from renewables on-site or purchased from the grid.

(II) H_2, the first educt for eMeOH synthesis, is obtained *via* H_2O electrolysis or industrial streams providing high concentrations of H_2 (*e.g.* coke oven gas from steel mills). The PtM process is investigated with the intent to minimise CO_2 emissions. For this purpose, H_2 used in hydrogenation should not be generated (in-)directly from fossil resources (*e.g.* steam reforming of CH_4 and H_2O electrolysis powered by the electricity grid mix). Please note that a valuable by-product of H_2O electrolysis is high purity O_2, which will be discussed in the following evaluation.

(III) CO_2, the second educt for eMeOH production, is captured from industrial processes, biogas or even ambient air.[35–38] Source dependent purification of the CO_2 is necessary.

(IV) Compression of the feed H_2 and CO_2 and the associated energy demand. This will be source dependent.

(V) Temporary storage, the size of which will be related to the fluctuation of the electricity production and the range of the systems' dynamics.

(VI) Catalytic conversion of H_2 and CO_2 to MeOH is based on established technology. Recent studies focus on higher efficiency and dynamic operation.[23,31,39,40]

(VII) Synthesis is followed by a purification step based here on distillation.

The PtM process steps that are varied within this study are marked in orange (*i.e.* power supply, CO_2 source, H_2 storage, and MeOH synthesis; Fig. 1). The non-variable components of the PtM process steps are marked in blue (*i.e.* polymer electrolyte membrane electrolysis (PEMEL), compression and pressure levels, and distillation).

Technical analysis – general framework, examined PtM scenarios and process variables

A total of six different PtM production scenarios (each with two different CO_2 sources) are considered (Fig. 2). In this study, two different electricity sources are considered: a constant grid supply (scenarios 1–4) and a local power supply (scenarios 5 and 6) from a 36 MW onshore wind park (which in turn provides a dynamic, fluctuating electricity supply for this study). Grid connected energy is further differentiated as a constant full load power supply (scenarios 1 and 2) or a price dependent power supply (scenarios 3 and 4), (*i.e.* dual tariff based on electricity availability). Wind park electricity supplies a 100% dynamic electrolyser and a MeOH reactor differentiated into a dynamic ($20\% < P_{RL} < 100\%$, scenario 5) and a stationary model ($P_{RL} = 100\%$, scenario 6; P_{RL} = rated load). A dynamic MeOH synthesis reactor is at present not realised at the industrial scale as a consequence of the unknown effects on catalyst degradation/behaviour and the challenges of efficient heat integration (*i.e.* when operating under partial load). Dynamic simulation of each system leads to H_2 storage capacities between 'zero H_2 storage' and a '50 000 kg H_2 storage' reflecting the synthesis ability of flexible operation. The investigated scenarios are additionally differentiated regarding the application of electricity fees. Finally, all six resulting scenarios are evaluated based on the utilisation of two different CO_2 sources, namely from a biogas treatment plant (biogenic CO_2, indicated by 'B') and from an ammonia production plant (fossil CO_2, indicated by 'A'). CO_2 from biomass offers, besides air capture methods, the only possibility to close the global carbon-loop and offer a long-term solution for a PtL-process independent from fossils. Regarding ammonia plant-derived CO_2, a high purity is assumed and is considered an exemplary scenario for other industrial processes (*e.g.* cement, steel or bioethanol production). In the subsequent section a down-stream modular overview of the evaluated PtM process is provided. The various parameters identified for the generated economic evaluation are discussed and simulation results based on a combined Matlab/Simulink-based analysis and previously reported data are used.[41,42]

Electricity purchase

Purchase from the German electricity market (scenarios 1–4): these scenarios refer to the spot market (*i.e.* short-term purchase, normally the next day) whereby the final purchase price is dependent on the actual spot market price plus taxation, fees and apportionments (electricity, grid and concession fee, the EEG, 'KWK' and offshore apportionment and the apportionment according to §19 'StromNEV' and §18 'AbLaV').

Low spot market prices are available in times of high production from RE (*e.g.* low or even negative residual load),[43] or during periods of low energy demand (*e.g.* at night). Therefore, electricity purchase during such periods can aid in the reduction of the final production cost. The stock price is, however, not the biggest share since *ca.* 80% can be attributed to taxation and fees. Under certain circumstances (*e.g.* amount of energy consumed/total utilisation hours/specific electricity cost intensity), it is commonplace in Germany, as an industrial customer, to receive a tax reduction down to 15% (EEG 2017). For this study, electricity prices are calculated either with tax and fees (scenarios 1 and 3) or based on the aforementioned reduction of fees and taxes (scenarios 2 and 4). The respective reduction was calculated depending on the specific electric energy demand in the scenarios. Furthermore the calculation model differs between electric energy demand of the electrolyser and the 'rest' of the plant (*i.e.* compressors and eMeOH-plant). According to 'Energiewirtschaftsgesetz' (EnWG, §118 (6)) and 'Stromsteuergesetz' (StromStG, §9a), electrolysers are found to be exempt from the grid fee and electricity tax, respectively. The exemption from EEG apportionment for electrolysers and the energy demand of additional components in the PtM system takes effect after the first consumed GWh of electrical energy. After analysing the specific tax and fee reduction potential for each scenario, electricity prices are found to be between 3.11

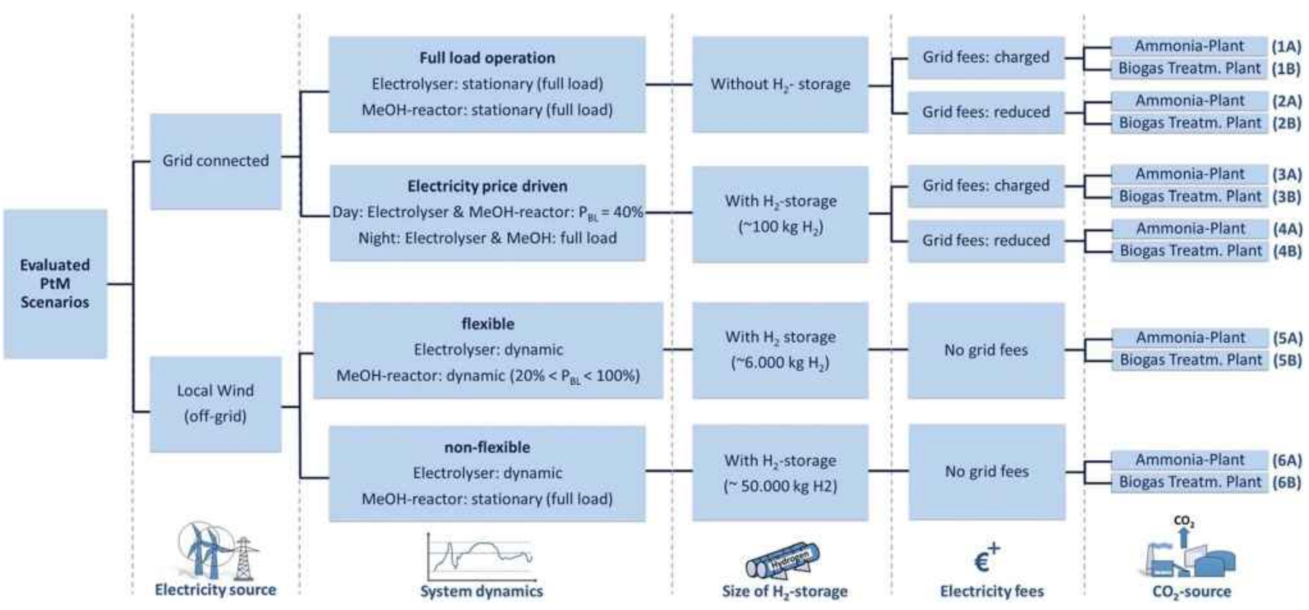


Fig. 2 Overview of the six different "Power-to-Methanol" (PtM) scenarios (1–6) evaluated in this study; each differed in the sourced CO_2 either from an ammonia-plant (A) or from a biogas upgrading plant (B).

and 3.28 ct€ per kWh with reduction, or 14.29–14.63 ct€ per kWh without the reduction. The partial reduction of EEG apportionment (6.88 ct€ per kWh full/0.18 ct€ per kWh reduced), grid fees (2.26–2.77 ct€ per kWh full/0.00 ct€ per kWh reduced) and electricity tax (2.05 ct€ per kWh full/0.00 ct€ per kWh reduced) is the most significant since they have the largest reduction potentials.

Another possibility for electricity purchase is based on participation in an operating reserve market (support of grid stability), where negative reserve (increase of load/H_2 production) and positive reserve (decrease of load/H_2 production) could both be provided. In our study, the German operating reserve market has been utilised as a model. Since market entry in this case is simplified (*e.g.* pooling is possible), there are more and more participants in the market, resulting in decreasing revenues. The exact economic benefit of participation in the control energy market, whilst an important global consideration, is not discussed in this study. Kopp *et al.* had a first evaluating insight into this topic in their work regarding the PtG plant in Mainz, Germany.[44]

It is important to note that PtM scenarios using grid electricity only produce eMeOH, if mainly RE is fed into the grid. The RE share will keep increasing following German/EU Climate Targets (>80% RE in 2050).[44]

Electricity purchase from a local onshore wind park with a rated power of 36 MW (scenarios 5 and 6): for the simulation, values at minute intervals have been applied. If insufficient wind electricity is available for H_2 production (*i.e.* the amount required for eMeOH production), the difference is covered by either the flexible adaption of the eMeOH production rate (scenario 5) and/or an H_2 storage (scenarios 5 and 6). A limited flexible operation of eMeOH synthesis is a novelty, and therefore for the purposes of this study is assumed technically feasible. For the wind electricity driven scenarios 5 and 6 an additional grid connection to acquire electricity in periods of low wind supply is not considered for the purpose of a remote renewable scenario. The levelized cost of electricity (LCOE) from onshore wind energy is assumed to be 4.4 ct€ per kWh,[45] without any additional fees or taxes since wind electricity is used for personal consumption and without grid connection (as defined by the "Renewable Energy Act" ("Erneuerbare Energiengesetz" EEG) of the German Government in 2014 (§61, subsection 2, sentence no. 2)).[46]

H_2 production and O_2 valorisation

A PEM electrolyser (PEMEL) is adopted in this study for H_2 production as a consequence of its ability to operate under both dynamic and steady state conditions with only a marginal reduction in efficiency.[1,47] During dynamic operation, a PEMEL is capable of following fast load changes and load-ramp curves with high inclination ($\pm$138% P_{RL} per min).[42] Large-scale PEMELs with production capacities >10 N m^3(H_2) h^{-1} do offer efficiencies as high as alkaline electrolysers (AELs) (PEMEL: <*ca.* 5.3 kWh$_{el}$ per Nm^3(H_2); AEL (pressurised): <*ca.* 5.0 kWh$_{el}$ per Nm^3(H_2); both system-related); a positive technical learning curve has been traversed over the last few years, indicating that further efficiency improvements can be expected in the coming decade.[48–50] Additionally, PEMELs operate very well under variable loads, down to $P_{RL} = 0\%$ and an overload of up to $P_{RL} = 150\%$ (for up to 15 min).[51,52] The product purity from the PEMEL operation is high grade (*i.e.* H_2 purity > 99.9 vol%), whilst the operating temperature is typically low (50–100 °C), facilitating a faster start-up (*i.e.* in comparison to an alkaline electrolyser).[52] The operating PEMEL parameters evaluated in this study are displayed in Table 1.

Molecular O_2 is produced as a high purity by-product and as such is included in this study as a consequence of its valorisation potential. The selling price depends on purity, with O_2 purities > 99.99% (and without S or CO impurities) making it useful for many high-tech applications (*e.g.* medical use in hospitals, electronics industry, and oxy-fuel processing).[53] If possible, O_2 is utilised locally to avoid the associated energy intensive liquefaction and transport needs.[3] For these reasons, the use of O_2 from large electrolysers in nearby chemical/energy plants is considered the most appropriate option (*e.g.* in epoxide/polycarbonate production *via* oxidation of propylene and CO_2 addition).[54]

CO_2 sourcing

Technical processes for the capture of CO_2 include both chemical and physical absorption processes (*e.g.* amine scrubbing, Rectisol®, Selexol®, cryogenic methods, *etc.*) based on the use of a variety of solvents, membranes and solid capture media.[9,35,36,55–57] Likewise, there are various CO_2 sources, which can be distinguished on the basis of volumetric output, CO_2 concentration, presence of impurities, pressure level, CO_2 origin (biogenic/fossil), impact on up-stream processes due to carbon capture, and CO_2-price (prices from negative to positive possible).[35,55] Which CO_2 source is captured by which method depends on the operating conditions of the emitting process. Concurrently, the downstream CCU process has its own requirements regarding required purity, tolerable impurities and volumetric demand.

In this study, two different CO_2 sources are considered, namely a biogas treatment plant and an ammonia plant. In the case of biogas, CO_2 is separated during a treatment process of the raw biogas. This is conventionally composed of CH_4 (70–50 vol%) and CO_2 (30–50 vol%), with the exact composition influenced by the biomass or waste being converted, which also dictates the presence of other compounds and impurities (*e.g.* N_2, H_2S, H_2O, and organosulfur compounds). Taking Germany again as the example, the quality requirements for the feed-in of treated biogas to the gas grid are regulated.[58,59] CO_2 sourced from biomass is designated as biogenic.

Table 1 PEM electrolyser: parameters for dynamic simulation

Rated load, P_{RL} [MW]	12
Efficiency, η_{Ely} [kWh per Nm^3]	4.76
Output pressure, P_{H_2} [bar]	30
Grid connected scenario	P_{RL}: 40% (day), 100% (night)
Wind electricity driven scenario	0% < P_{RL} < 100%

For CO_2 capture from an ammonia plant, it is assumed that CO_2 is already a component of an existing ammonia production process and therefore is designated as fossil-based (from steam methane reforming as a process related step in ammonia production).[60]

H_2 storage

All process scenarios examined in this study, apart from the full-load power supply scenario, include H_2 storage facilities. In this study, the incorporated H_2 storage units consist of medium pressure vessels operating dependent on a load capacity in the range 30 bar < $P_{H_2,storage}$ < 200 bar. The required size and range of this storage has been identified, based on dynamic simulation *via* Matlab, to be in the range 100 kg(H_2) < $m_{H_2,storage}$ < 50 000 kg(H_2). It is important to mention that H_2 storage with a 50 tonne capacity would rather be realised as an underground cavern facility. However, due to a strict dependence on local conditions, the possibility of an environmentally sound disposal of the resulting brine, and socio-economic conditions in the case of underground cavern storage, and for a better comparability, the installation of storage vessels is assumed for all the evaluated scenarios in the present study.

In the first of the examined scenarios 1 and 2 (*i.e.* grid connected, constant supply), no storage is necessary as a consequence of a constant H_2 production. The resulting H_2 mass flow of 5.47 t(H_2) d^{-1} is directly converted to MeOH. For the other scenarios, H_2 storage requirements depend on the assumed dynamics of the MeOH synthesis reactor (Fig. 2). In wind powered scenarios, MeOH mass flow is a function of the actual wind power, the H_2 storage pressure and the possible dynamics of the MeOH synthesis reactor (Fig. 3).

Compressor

Both H_2 and CO_2 streams require compression since MeOH synthesis is favoured under pressure (here designated at 40 bar). The output pressure of the PEMEL is 30 bar. In the case of direct feed *via* a by-pass to the MeOH synthesis reactor, a single-stage H_2 compression step is deemed technically appropriate. If sourced from H_2 storage, a maximum pressure of 200 bar is available. For the compression of the PEMEL H_2 product stream for storage (*i.e.* 30 to 200 bar), a two-stage reciprocating compressor is considered. For the CO_2 stream where a compression from ambient to 40 bar pressure is necessary, a two-stage reciprocating compressor is utilised. The compressor specifications are based on the manufacturer's operational details (*e.g.* in terms of energy demand).

MeOH production and distillation

The hydrogenation of CO_2 takes place under exothermal reaction conditions (eqn (1)–(3)). The final theoretical MeOH yield is based on a stationary simulation model generated using the ChemCAD® software platform. The selected reactor type is designated as an ideal adiabatic tube reactor with a reaction pressure of 40 bar.[42] For calculation of the CO_2 amount needed for MeOH production, a per pass conversion efficiency of 90% is adopted resulting in 10% of the CO_2 feed not being converted to MeOH. Evaluation of the simulation is based on the results produced from the hydrogenation of CO_2 on a lab scale MeOH production facility operated at Fraunhofer ISE. In this study, the total theoretical amount of MeOH produced varies between 4000 and 10 000 t_{MeOH} a^{-1}.

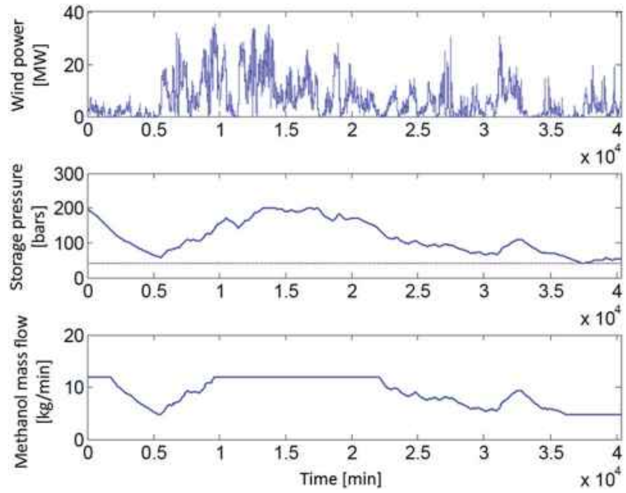


Fig. 3 Operating ranges for scenario 5: 'wind electricity driven, flexible' methanol production.

Economic analysis – general framework

To establish a fair economic evaluation, the framework conditions for the study have to be defined (Table 2). Referring to the energy needed for eMeOH production, calculations include the electric energy demand. A large share of thermal energy demand results from distillation and is mainly covered by the exothermal MeOH synthesis. Cooling duties and advanced heat integration are not yet considered and will be addressed in a later report. Where possible, the economic evaluation is based on price data from manufacturers within the model market (*i.e.* Germany). Otherwise, values are taken from literature sources as indicated and adjusted accordingly for use with eqn (4).[61]

$$\mathrm{Co}_1 = \mathrm{Co}_2\left(\frac{C_1}{C_2}\right)^m \tag{4}$$

Co_1: plant costs new, Co_2: plant costs old, C_1: plant capacity new, C_2: plant capacity old, and m: digression coefficient = 0.67.

If not included in the component's investment cost, additional costs for delivery and setup are added at a proportionate share of the total investment cost (TIC). Maintenance costs are either based on literature values for the specific component or comparable processes. Not considered in this economic evaluation are costs associated with land, buildings or employees. As mentioned earlier, alongside MeOH, the by-product of H_2O electrolysis, namely O_2, is also considered as a valuable product in the plant and its potential sales are also included. Credit for

Table 2 Economic assumptions: plant investment & operating expenses

Recovery period	10 years	—
Interest rate	2.5% p.a.	Ref. 62
PEMEL specific investment	800€ kW^{-1}	Ref. 48, 49, 63 and 64
PEMEL grid connection	66€ kW^{-1}	Ref. 48
PEMEL stack life-time	50k hours	Ref. 64
PEMEL stack reconditioning cost	2.0% of spec. invest.	Ref. 64
PEMEL maintenance & insurance	2.0% of spec. invest.	Ref. 64
H_2 storage specific investment	Depending on storage size	Ref. 65
H_2 storage maintenance & insurance	2.0% of spec. invest.	Ref. 62
MeOH synthesis specific investment	810€ t^{-1} a^{-1}	Ref. 66
MeOH synthesis maintenance & insurance	10.0% of spec. invest.	Ref. 66
Other installation maintenance & insurance	2.0% of spec. invest.	Ref. 62
Technical staff	14 h per week at 100€ h^{-1}	Own estimate
Plant buildings and facilities	7.0% of spec. invest.	Ref. 64
Engineering, planning, delivery, and setup	Inspired by internal experiences	—

O_2 is considered at 50€ $t(O_2)^{-1}$,[67] which is a relatively conservative value. Atsonios *et al.*[29] and Matzen *et al.*[30] considered a credit of *ca.* 75€ $t(O_2)^{-1}$ for their calculations (see Table 5) (NB: any possible future increase of installed electrolysis capacity may act to decrease the impact of the O_2 market value, unless a large increase in oxidation chemistry is anticipated).

The supply cost of CO_2 differs for different sources. From the considered biogas plant source, the CO_2 production cost is assumed to be 0€ $t(CO_{2,capt.})^{-1}$, as this is essentially a waste product from biogas cleaning and therefore, the cost for separating CO_2 is assigned to CH_4 production cost. Based on ammonia production, CO_2 capture costs are 3€ $t(CO_{2,capt.})^{-1}$.[36,68] Furthermore, assuming that avoided CO_2 emissions will also be considered within the European Emission Allowances (EUA) in the near future, a projected price of −10€ $t(CO_{2,emitt.})^{-1}$ is obtained. These allowances are tradable and the resulting CO_2 feedstock price is −7€ $t(CO_2)^{-1}$ (Table 3). Biogas treatment plants do not take part in the EUA trade, since the emitted CO_2 is of biogenic origin.

The operating and full load hours of the PEMEL and the MeOH synthesis reactor differ for the different scenarios. For purely wind electricity driven scenarios, the PEMEL full load hours are in the range of 3585 to 3896 h a^{-1} and the operating hours (the period during which the PEMEL is operational at any load factor) at 7044 h a^{-1} (Table 4). The costs for maintenance and replacement of the PEMEL stacks do reflect the specific operating hours and a predicted stack life-time of 50 000 h. Furthermore, the yearly amortisation payments are calculated based on a linear depreciation over 10 years.

Table 3 Evaluated CO_2 sources

	Biogas treatment plant	Ammonia plant
Capture cost [€ $t(CO_{2,capt.})^{-1}$]	Excluded	3
CO_2 certificate price [€ $t(CO_{2,emitt.})^{-1}$]	0	−10
CO_2 feedstock price [€ $t(CO_2)^{-1}$]	0	−7
Output pressure [bar]	Atmosph.	Atmosph.
Environmental burden	Biogenic origin	Fossil origin

Results and discussion

Investment cost

The TIC for every investigated scenario is found to be within the margin of 14.4–27.1 M€ (Fig. 4). The TIC is strongly influenced by the investment cost related to PEMEL use. The PEMEL is a necessary procurement, with an assumed cost of 800€ kW_{inst}^{-1} without and 866€ kW_{inst}^{-1} with grid connection related to installed capacity (kW_{inst}). Considering that the mid-term (for the year 2023–2030) cost of a PEMEL on the MW-scale ranges from 750 to 1600€ kW_{inst}^{-1},[48,49,63,64] these values can be seen as an optimistic target value. The European Multi-Annual Implementation Plan of the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) targets 720€ kW_{inst}^{-1} for PEMEL systems with production capacities <1000 $kg(H_2)$ d^{-1}.[51] Schmidt *et al.*, based on interviews with experts from industry and academia, quantify PEMEL specific investment in 2030 between 850 and 1650€ kW_{inst}^{-1} under the assumption of no changes in technology funding and without a production scale-up. Intensified R&D funding as well as a production scale-up could lead to a further 24% reduction in specific investment.[52] Saba *et al.* reported even lower cost estimations of 397–955€ $kW_{HHV\text{-}output}^{-1}$.[50]

All scenarios take a PEMEL as a basis, even though the grid-connected scenarios would be able to function reasonably using an AEL electrolyser. As mentioned earlier, the TIC will likely decrease in the future as a consequence of further technology development, efficiency improvements, and more widespread use, with a target value of 440€ kW^{-1} considered desirable for large water electrolysis systems >10 MW.[67] The 12 MW PEMEL included in this investigation has a TIC of 9.6 M€ (without a grid connection) and 10.4 M€ (with grid connection), representing *ca.* 60–70% of the TIC of the overall process. An exception to this observation is the wind-driven scenario using a non-flexible MeOH reactor (scenario 6), since a large H_2 storage is included, representing a significant expense in itself (*i.e.* TIC (PEMEL) = 35%; TIC (PEMEL + H_2 storage) = 79%). Mignard *et al.* arrived at a similar conclusion in a previous report where the electrolyser's share of the TIC is within 65–82%, by far the biggest share, followed by the H_2 storage and

Table 4 Operating hours and production capacities

	Grid connected constant supply	Grid connected electricity price driven	Wind electricity driven flexible	Wind electricity driven non-flexible
PEM-electrolysis – production capacity [t a^{-1}]	1906	992	791	1210
PEM-electrolysis – energy demand [GWh a^{-1}]	100.80	55.44	43.02	46.75
PEM-electrolysis – operating/full load hours [h]	8400/8400	8400/4620	7044/3585	7044/3896
Hydrogen storage – volume [m^3]	—	6	345	2840
Carbon capture – capturing capacity [t a^{-1}]	15 225	7765	6392	9780
Methanol reactor – production capacity [t a^{-1}]	10 031	5139	4188	6408

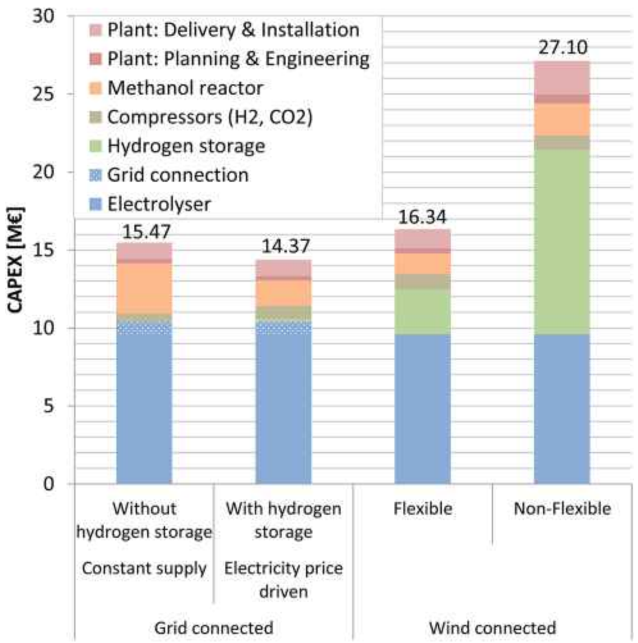


Fig. 4 Investment cost (CAPEX) of the different plant scenarios in M€.

compression cost, with a share of 9–16%.[27] The impact of investment in the MeOH reactor depends on the annually produced MeOH, which is assumed in this study to be 810€ t^{-1} a^{-1}.[66] Therefore, the grid connected scenario without H_2 storage (scenario 1) has the highest MeOH reactor cost (3.3 M€), since this scenario produces the greatest amount of product. The potential of additional cost for a flexible reactor is not considered in detail. Excluding this mentioned scenario, the MeOH synthesis reactor's influence is comparatively low. For future assessments a detailed investigation of the cost incurred by a dynamic reactor design should be included. Additionally, since methanol from syngas with high CO_2 content and H_2 potentially offers higher purity (free of most ketones, paraffins and other by-products) compared to methanol from syngas, a reduced demand for distillation could have a cost decreasing effect.[23,69]

Operational & annual costs

Each scenario has a different operational mode with different resulting operating costs, ranging between 4.00 and 12.93 M€ a^{-1} (Fig. 5). It can be seen that the main factor is electricity cost, as long as a reduction in taxation/fees is not possible (left bar of each scenario). In that case, the operational cost (OPEX) is *ca.* 2.5 times higher than in scenarios including a reduction, which results in a share of electricity cost of *ca.* 70–81% of the OPEX (with 45–59% reduction). Wind energy-based scenarios however indicate that the electricity cost share lies approximately between 42 and 44% and therefore represents a reduction relative to grid-connected scenarios. Due to the high electricity demand of the PEMEL, slight changes in the electricity price have significant impacts on the electricity cost. A similar observation was made by Atsonios *et al.*[29] Although this report assumed a low electricity price of 2.9–5.0 ct€ per kWh, electricity still represents the largest share of the OPEX. The CO_2 feedstock costs by comparison (*e.g.* for ammonia plant scenarios) are very low (*i.e.* 19 000–46 000 € a^{-1}). As mentioned earlier, the trade of the EUA in the amount of recycled CO_2 is assumed to be possible in the near future. Since this generates a negative value, it may even lead to positive revenues (Table 3). However, the assumed certificate price is very low at the current time (*ca.* 10€ $t(CO_2)^{-1}$) and the revenue, based on current values, is accordingly small. It is important to consider that the EUA value is increasing and a rise to just 30€ $t(CO_2)^{-1}$ would lower the OPEX by between 1.7 and 5.0% (or 0.17–0.3 M€ a^{-1}).

Methanol production cost

The eMeOH production cost (MPC) is calculated using eqn (5).

$$C_{\text{spec.}} = \frac{A + C_{\text{total}}}{M_{\text{total}}} \tag{5}$$

$C_{\text{spec.}}$: specific production cost, A: annuity, C_{total}: annual operational cost, and M_{total}: total amount of produced methanol.

Currently, the MPC of all considered scenarios (Fig. 6) is above the actual market price (*i.e.* Methanex average 2017 (Jan to June):[70] 410€ $t(\text{eMeOH})^{-1}$), which has featured a low-level upward trend of +3.20€ per month over the last 2.5 years. The scenario with the lowest MPC (scenario 2B, grid connected with constant supply, fee reduction, without H_2 storage, CO_2 from biogas, 608€ $t(\text{eMeOH})^{-1}$) costs 1.5 times the possible market revenues, whereas the most uneconomical scenario (scenario 3A, electricity price driven, without fee reduction, with H_2 storage, ammonia, 1453€ $t(\text{eMeOH})^{-1}$) is 254% above the 2017 market price level. The electricity price has a huge impact on the MPC: where a fee reduction is not possible, MPCs are in the

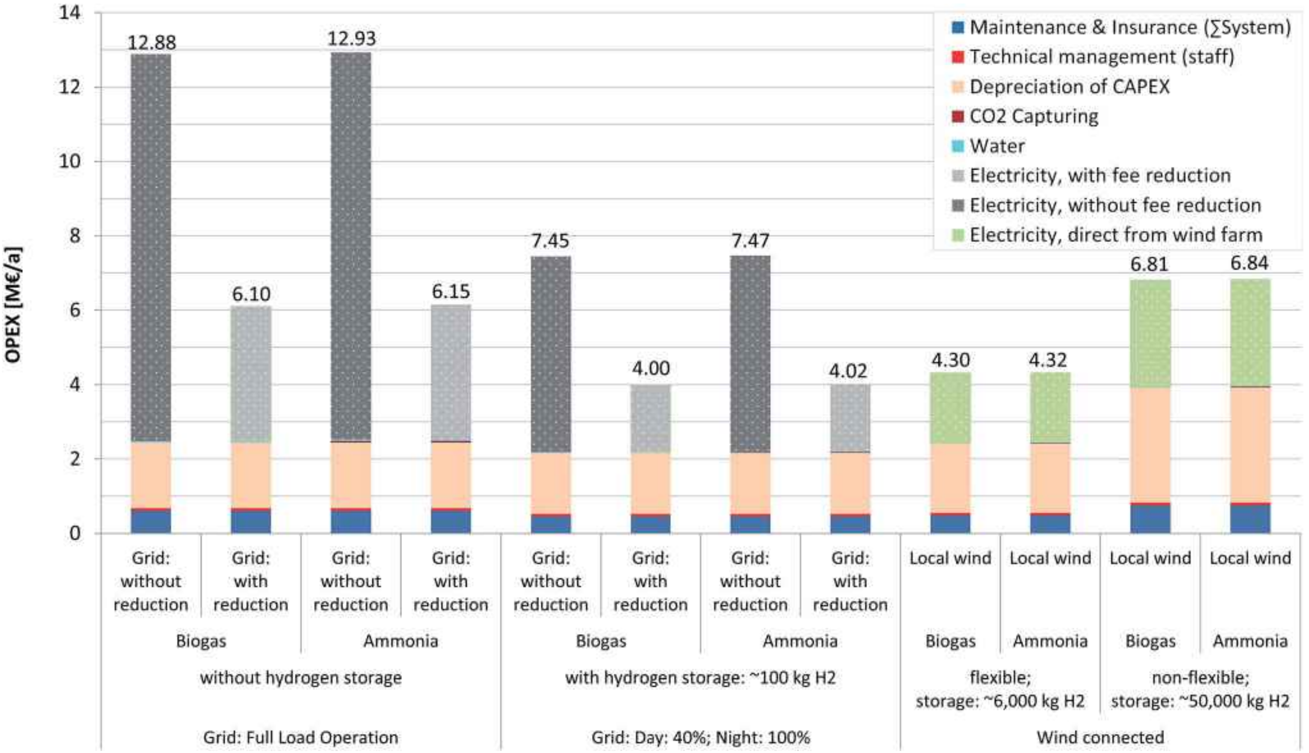


Fig. 5 Operational cost (OPEX) of the evaluated scenarios in M€ per year.

range of 1284 to 1453€ $t(eMeOH)^{-1}$. If taxation and fees do not have to be paid in full, the MPC will decrease to 608–782€ $t(eMeOH)^{-1}$. The wind driven scenarios feature MPCs in the range of 1028–1067€ $t(eMeOH)^{-1}$, which are characterised by large H_2 storage capacities and associated high investment costs.

In this study, a positive value of 50€ $t(O_2)^{-1}$ for selling the electrolyser by-product was used. Previously Atsonios *et al.* considered an O_2 revenue of 87€ $t(O_2)^{-1}$ reflected in a decrease in eMeOH production cost (*ca.* 10% reduction as a consequence of O_2 sales).[29] Matzen *et al.* also included O_2 sales in their process evaluation and concluded that a price of 75€ $t(O_2)^{-1}$ had a positive impact on the economic feasibility of their process.[30] Likewise, Rivarolo *et al.* assumed a much higher market value of 150€ $t(O_2)^{-1}$.[34] Compared to the 50€ $t(O_2)^{-1}$ used in this study, this results in a difference of 150€ $t(eMeOH)^{-1}$ (1.5 $t(O_2)$ $t(eMeOH)^{-1}$ produced). For further analysis a detailed evaluation of the necessary process steps for pressurizing, bottling and transportation of O_2 has to be included as well as a discussion of the development of the O_2 market price in the case of increasing market penetration for electrolyser technology.

Sensitivity study

The economic feasibility of PtM is influenced by a number of parameters, and it is essential to know which parameters, besides the obvious electricity price, have a high impact on the process economy. Therefore, a sensitivity study was performed for the wind-powered, flexible MeOH synthesis based on biogas-derived CO_2 (scenario 5B). Based on a biogenic CO_2 source and a local supply of wind power the chosen scenario represents the most preferable option up to now regarding the establishment of a sustainable eMeOH production route. Only one parameter has been varied at a time; the unchanged parameters are based on the one set for the economic evaluation of scenario 5B (see also Table 2). Displayed are the costs (negative slope) and benefits (positive slope); the steeper the slope the stronger the influence of the parameter on the process economy (Fig. 7). The most important factor is identified to be the MeOH selling price, since it has a direct impact on the specific profit. Increasing MeOH selling prices are consequently directly visible in the process economics. The electrolyser investment is another important impact factor. At 12 MW, a reduction of the specific investment has a large impact on the TIC. A specific investment reduction of only −10% leads to an investment decrease of 1 M€ (−6.2% of the TIC). If an investment target value of 440€ kW^{-1} for water electrolysis systems could be reached, the TIC would decrease by an amount of *ca.* 4.3 M€ (−27% of the TIC). Regarding the expected price decrease of the PEMEL, eMeOH production costs should decrease in the long term. Thirdly, as already discussed in the context of operational cost, the electricity price has a strong impact on the overall process economy. Marginal changes in electricity price are directly visible in the eMeOH production cost. Therefore, the availability of green but inexpensive electricity (*e.g.* in periods of excess or over-production and regions with significantly lower RE generation costs) is a basic prerequisite for an economic elaboration of PtM. Although the investment in the methanol synthesis reactor is not a key indicator for the TIC, scaling-up of

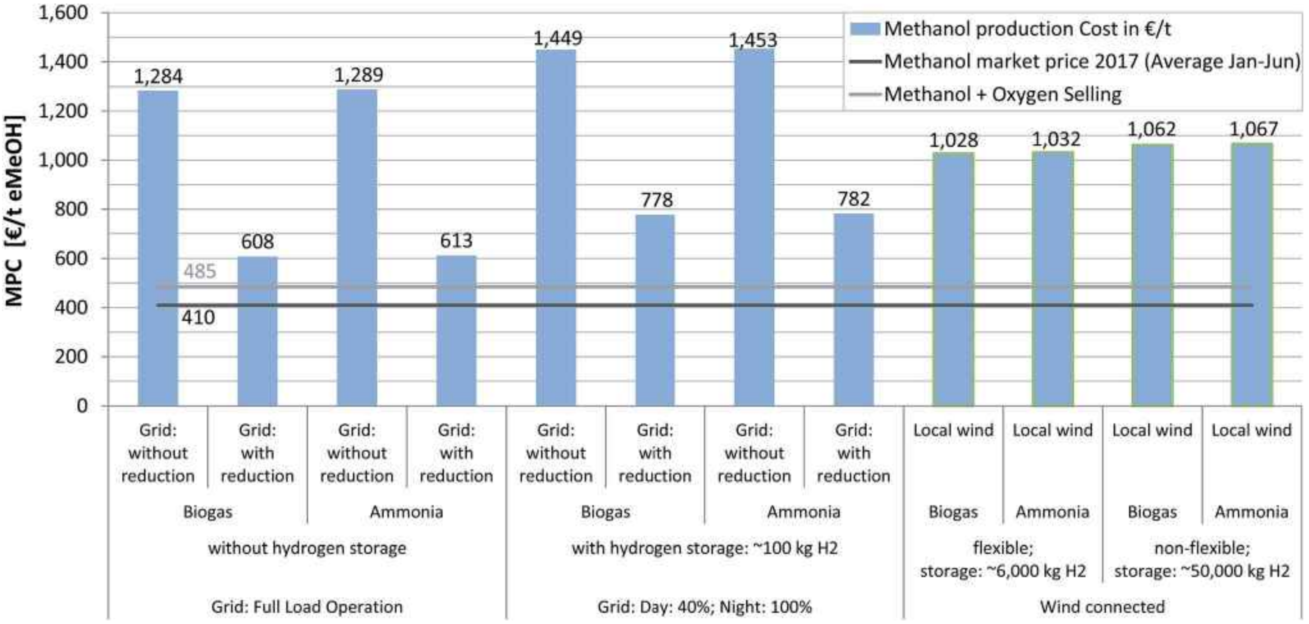


Fig. 6 Methanol production cost (MPC) for the evaluated scenarios in € t(eMeOH)$^{-1}$.

the methanol reactor will also have a decreasing effect on the reactor specific investment cost and hence on the TIC of the PtL systems. Hence, to improve the economic viability of PtM and decrease the difference between the current market price level and the production cost, the above-mentioned parameters are important starting points to be considered and in turn optimised.

Evaluation

To provide an overview and classification of the results generated from this study, in comparison with previously reported studies and data, Table 5 has been compiled. In this comparison, monetary values that were not given in € were calculated based on a time-dependent currency exchange rate (the average exchange rate in the year of the study). For a better comparability of the values, eMeOH production costs were also converted based on the current currency exchange rate (average 2017). For the calculation of production capacity, 350 days per annum were assumed if no value for working h a^{-1} was available. All values not directly stated in the studies were calculated on the basis of the available values (where possible).

Due to the different parameter assumptions used in the calculation of eMeOH production costs, the results vary considerably from study to study. Therefore selection of system boundaries, system components and framework conditions is critical as they have a significant impact on the final results and as a consequence, different studies should be compared carefully.

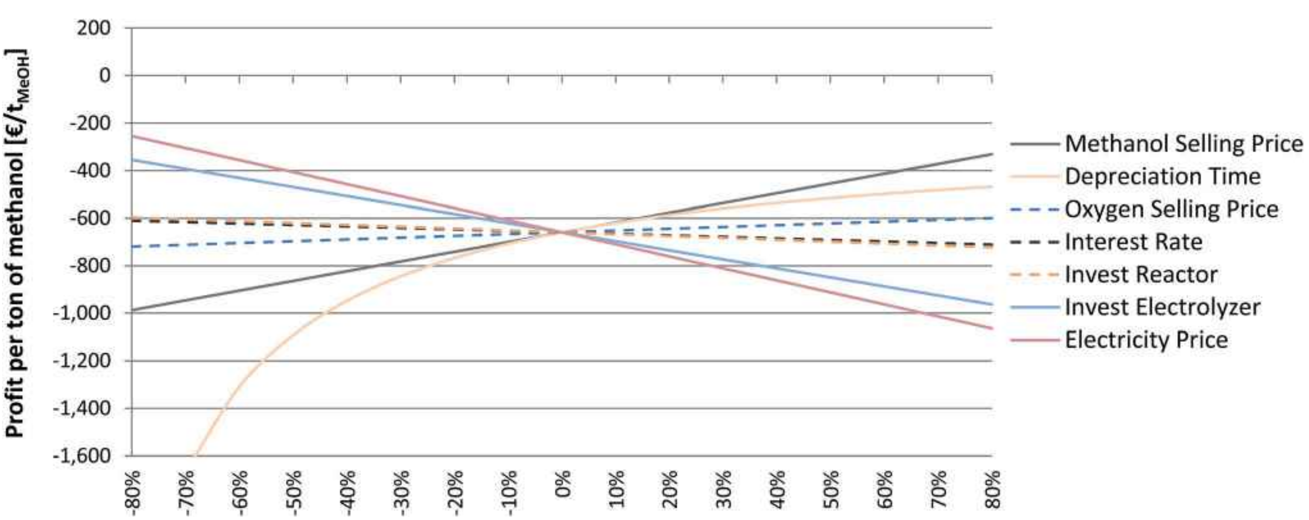


Fig. 7 Sensitivity study for the wind powered, flexible synthesis based on biogas-derived CO_2 (scenario 5B).

Table 5 Comparison of different PtM studies

Electricity		Electrolyser			CO_2		Storage		Methanol reactor + distillation					
Source	Price [ct€ per kWh]	Type	Spec. invest [€ kW^{-1}]	O_2 price [€ $t_{O_2}^{-1}$]	Source	Spec. cost[a] [€ $t_{CO_2}^{-1}$ a^{-1}]	H_2	CO_2	Spec. invest[b] [€ t_{MeOH}^{-1}]	Plant capacity [t d^{-1}]	Pressure level [bar]	Plant depreciation time [a]	Methanol production cost [€ t_{MeOH}^{-1}]	Source
Grid	3.74–13.43	PEM 12 MW	800	50	Biogas/ammonia	0/3	No	No	1514	29	40	10	608–1615	This study
Grid	3.67–14.13	PEM 12 MW	800	50	Biogas/ammonia	0/3	6 m^3	No	2745	15	40	10	816–1969	This study
Wind onshore	4.4	PEM 12 MW	800	50	Biogas/ammonia	0/3	345 m^3	No	3830	12	40	10	1040–1051	This study
Wind onshore	4.4	PEM 12 MW	800	50	Biogas/ammonia	0/3	2840 m^3	No	4144	19	40	10	956–967	This study
Hydro power	1.3	—	—	—	Flue gas/atmosphere	—	—	—	—	200	—	15	258/387	1999-Specht and Bandi
Hydro power	2.5	—	—	—	CPP/atmosphere	—	—	—	—	200	—	15/20	529/717	1999-Specht *et al.*
RES	1.5–2.2	AEL 100/500 MW	422–1409	102	Flue gas (CPP)	—	Floating head/pressurised tanks	—	1299–2420	178–372	50	15	498–711[c] 429–613[d]	2003-Mignard *et al.*
Grid/RES	4	AEL 2 MW	200	Sold/used	Flue gas (CHP)	15	100–900 t_{H_2} underground gas storage	No	—	890	144	—	555	2010-Clausen *et al.*
Grid/CPP	2.9–5	AEL 140 MW	376	87	Flue gas (CPP)	44	Partially	—	—	318	65	25	870–913	2015-Atsonios *et al.*
Wind	6.3	AEL 41 MW[e]	440	75	Ethanol plant	—	Pressurised storage	Liquid storage	850	97	50	10	324–781[c] 389–938[d]	2015-Matzen *et al.*
CPP	9.5–12.1	—[f,g]	—[f]	—[f]	Flue gas (CPP)	0	—	—	497	1320	76	20	724	2015-Perez-Fortes *et al.*
—[f]	9.3	—[f,h]	—[f]	—[f]	Purchased	50	Yes[f]	No	1329	138	75	10	980	2015-Tremel *et al.*
RES	2.6/3.3	SOEC 50 MW	—	Used	Flue gas (CPP)	20	—	Buffer storage	1000	96/235	—	20	450/484	2015-Varone *et al.*

Table 5 (*Contd.*)

Electricity		Electrolyser			CO_2		Storage		Methanol reactor + distillation					
Source	Price [ct€ per kWh]	Type	Spec. invest [€ kW^{-1}]	O_2 price [€ $t_{O_2}^{-1}$]	Source	Spec. cost[a] [€ $t_{CO_2}^{-1}$ a^{-1}]	H_2	CO_2	Spec. invest[b] [€ t_{MeOH}^{-1}]	Plant capacity [t d^{-1}]	Pressure level [bar]	Plant depreciation time [a]	Methanol production cost [€ t_{MeOH}^{-1}]	Source
—	5	SOEC 20 MW	1469–5785 (SOEC)	Sold	—	3–10	—	—	6115 (SOEC)	58 (SOEC)	78	20	5459 (SOEC)	2016-Rivera-Tinoco *et al.*
		PEM 24 MW	600 (PEM)						883 (PEM)	49 (PEM)			891 (PEM)	
RES	1–5	PEM 2190 MW	700	40	Flue gas	40	—	—	1247–2495	5003	—	15	400–2775[i]	2016-Bertau *et al.*
RES + grid	3–5	AEL 1 MW	—	150	Biogas/purchase	10	—	—	—	—	80	10	—	2016-Rivarolo *et al.*

[a] Without including CO_2 certificate revenues. [b] Whole methanol plant. [c] Currency exchange rate in the year of the study (average). [d] Currency exchange rate of 2017 (average). [e] Calculated with the daily needed hydrogen amount for methanol production. [f] Outside system boundaries. [g] Assumed purchase price for hydrogen: 3090€ t^{-1}. [h] Assumed purchase price for hydrogen: 3000€ t^{-1}. [i] Conversion with low heating value (LHV), RES = renewable energy sources, CPP = coal power plant, and CHP = combined heat and power plant.

In this context, CO_2 sourcing differs from study to study. Typically, flue gas of a Coal Power Plant (CPP) is used. Varone *et al.* evaluated an integrated oxy-fuel/co-electrolysis process, where the oxy-fuel coal plant delivers the CO_2 and the O_2 by-product from the electrolysis is used for the oxy-fuel process.[32] Such combined processes are indeed logical but have not been considered thus far by other studies. Besides CO_2 captured from coal fired power plants is of fossil origin and should therefore not be part of a future energy system with the intention to provide sustainable fuels. The use of CO_2 from the atmosphere has been considered by Specht *et al.*,[25,26] and was recently revisited by the German-Swiss initiative of Audi, Sunfire and Climeworks.[71] More recent studies have considered this possibility but assess the acquisition cost to be still too high (*e.g.* Bertau *et al.*[3]). The EUA has, except for this study, so far not been considered by other authors. Depending on the source, the assumed costs to provide CO_2 lie between 0 and 50€ $t(CO_2)^{-1}$.

Compared to the actual MeOH market price of 410€ $t(MeOH)^{-1}$ (Methanex, average 2017),[70] almost all reported production costs are above the market price and the production *via* H_2 and CO_2 is as such not considered economical (when excluding additional O_2 sales). The cost of producing fMeOH from conventional processes *via* natural gas or coal varies depending on the geographical location of the production site between 51€ $t(fMeOH)^{-1}$ and 408€ $t(fMeOH)^{-1}$. They are therefore less expensive than any process based on RE, H_2 and CO_2.[6] If legislation or regulation regarding either RE or CO_2 conversion is established (*e.g.* within the EU), it remains to be seen how long these relatively low prices will be maintained. The smallest difference compared to the actual price level was reported in 1999, by Specht and Bandi (*i.e.* an eMeOH production cost of 258–387€ $t(eMeOH)^{-1}$).[25] This report was based on an unrealistically low electricity price of 1.3 ct€ per kWh (in 1999), leading in turn to low eMeOH production costs. However, recent reports demonstrate the rapid reduction in renewable electricity costs (*e.g.* solar power in Dubai[72,73] or Chile[74,75] with prices <3 ct€ per kWh).

The highest eMeOH production costs (excluding the production *via* High Temperature Solid Oxide Electrolysis)[33] with >2000€ $t(eMeOH)^{-1}$ were reported by Bertau *et al.*[6] In this work, eMeOH production costs depended on the electricity price and operating hours per year. With less than 2000 h a^{-1}, the MeOH production costs rise sharply, reaching values up to 2800€ $t(eMeOH)^{-1}$. Their calculations show clearly that the maximisation of operation is desirable regarding an economical production. A comprehensive PtL-overview focussing on electrofuels for the transport sector is provided by Brynolf *et al.*(2018).[76]

CO_2 avoidance cost

The economic inefficiency of the evaluated PtM scenarios on the one hand results from the energy and capital intensive structure of the PtM process itself. On the other hand cheap production conditions in the case of fossil based methanol production are reflected in a low market price. The lack of performing legislation taking into account the environmental burdens resulting from the production and provision of fossil based syngas leads to a 'free-lunch' for coal and methane based production of methanol. The internalization of direct and indirect environmental damage would mean further expenses for (up-stream) production processes which are very intense in terms of, for example, CO_2-, CFC-11- and SO_2-equivalents (eq)§ and can result in thorough land-occupation and -change. In terms of climate change and curtailing global warming CO_{2eq}-emissions are in the focus of scientific and political discussions. We evaluated the global warming potential (besides other impact categories) in a profound life-cycle-assessment (LCA) for the 'green' methanol production. In the frame of the present study we establish a first interconnection between the higher production costs and the possibly lower CO_{2eq}-footprint of the green methanol pathway compared to the fossil reference¶ by calculating the CO_2 avoidance cost:

$$CO_{2,AC} = \frac{PC_{eMeOH} - PC_{fMeOH}}{GWP_{fMeOH,C2G} - GWP_{eMeOH,C2G}}; \quad \left[€\ t_{CO_{2eq}}{}^{-1}\right] \quad (6)$$

The CO_2 avoidance cost ($CO_{2,AC}$) (eqn (6)) is expressed as the ratio of the differences between the production cost (PC) of green ('electricity based') and fossil based methanol (PC_{eMeOH} and PC_{fMeOH} respectively) and their respective global warming potentials (GWPs).

The $CO_{2,AC}$ can be seen as a key performance indicator when discussing the future of CCU processes and the establishment of an economy covering the majority of its C-demand with recycled carbon. It is important to note that the CO_2 avoidance cost is an indicator for the connection of economic and ecological efficiency besides many other ecological parameters such as water demand and indirect land use change or occupation. For a holistic evaluation of PtM and other CCU processes and their comparison to fossil based references a multitude of economic and, even more importantly, ecological parameters have to be included in a process' evaluation.

For the production cost of green methanol the results obtained in scenarios 5B and 6B with production cost of 1028 and 1062€ $t(eMeOH)^{-1}$, respectively, have been used. The production costs for fossil methanol depend on geographical location, ranging from 51€ $t(fMeOH)^{-1}$ (Saudi Arabia) to 408€ $t(fMeOH)^{-1}$ (Europe) and are dominated by the cost for the syngas feedstocks.[77] In order to put a price on the amount of avoided CO_{2eq} not emitted within the European region we decided to compare 'our' green methanol pathway (mainly dominated by the German electricity prices) with any fossil-based methanol production facility located within European borders. Therefore for this evaluation the production costs for fossil methanol are set to a 'European level' of 400€ $t(fMeOH)^{-1}$.‖ It could be argued that for other regions featuring significantly lower production costs for fossil methanol such as Saudi Arabia or China the difference between cheap fossil and cost-expensive green methanol production would increase. But likewise a lower levelised cost of renewable electricity would have a clear decreasing effect on green methanol production cost and would partly balance the cheap market conditions for the fossil production.

Regarding the GWP for the green methanol production the values are based on a life cycle assessment based on hydrogen from a wind-powered PEM electrolyser in combination with CO_2 from a biogas upgrading plant** (representing scenarios 5B and 6B). The LCA was performed using the Umberto NXT Universal software with the Ecoinvent-v3.3 database. With a GWP of 506 $kg(CO_{2eq})\ t(eMeOH)^{-1}$ during the production phase and an uptake ('molecular binding') of 1374 $kg(CO_2)\ t(eMeOH)^{-1}$†† the PtM process can be seen as 'netto-negative' (506–1347 = −868 $kg(CO_{2eq})\ t(eMeOH)^{-1}$) in terms of CO_{2eq}-emissions when evaluated by a cradle-to-gate approach. Expanding the system boundaries by containing also the utilisation of the produced methanol (cradle-to-grave, C2G),‡‡ all C-content will be oxygenated (1388 $kg(CO_{2eq})\ t(MeOH)^{-1}$) again and released into the environment. Utilisation could be in the MeOH-form as a partial fuel substitute or further processed to downstream derivatives such as DME or OME_{3-5}. In this case the resulting cradle-to-grave emissions would add up to 520 $kg(CO_{2eq})\ t(eMeOH)^{-1}$.§§

As a reference for the GWP of a European based fossil methanol production process we used the Ecoinvent process 'methanol production [GLO] from natural gas'.¶¶ Where possible the contained activities have been adjusted to an assumed methanol production in Europe. This accounted for the supply of natural gas for syngas production and the market for electricity as well as the provision of tap water. The adjusted EU-based fossil methanol production results in slightly higher specific CO_{2eq}-emissions (cradle-to-gate: 526 $kg(CO_{2eq})\ t(fMeOH)^{-1}$ (global) *vs.* 623 $kg(CO_{2eq})\ t(fMeOH)^{-1}$ (EU-based)) which mainly arise due to the transport intensive provision for the syngas production with natural gas/process heat in Europe (GWP_{100a}: +18.3 and +33.4% resp.). Concurrently the electricity supply shows a lower GWP (GWP_{100a}: −36.0%) presumably due to higher efficiencies in fossil electricity production and higher shares of renewables within the EU. For fMeOH also a complete oxygenation of the C-content is assumed for the utilization phase (1388 $kg(CO_{2eq})\ t(fMeOH)^{-1}$) resulting in cradle-to-grave-CO_{2eq}-emissions of 2011 $kg(CO_{2eq})\ t(fMeOH)^{-1}$.

Based on these values the CO_2 avoidance costs are 421€ $t(CO_2)^{-1}$ (scenario 5B) and 444€ $t(CO_{2eq})^{-1}$ (scenario 6B) giving

§ Listed examples for equivalent (eq) emissions: CO_{2eq}: climate change, $CFC\text{-}11_{eq}$: stratospheric ozone depletion, and SO_{2eq}: acidification.

¶ In this evaluation: methanol production based on syngas from steam-reforming of natural gas.

‖ In the case of assuming lower fossil MPC for example for any production facility in Saudi Arabia or China, the green MPC would also decrease presumably because of lower renewable electricity generation cost (PV electricity in Abu Dhabi @ 2.45 ct€ per kWh; in Chile @ 2.91 ct€ per kWh; and levelised cost of electricity for large PV plants within the G20 states below 4.10 ct€ per kWh).

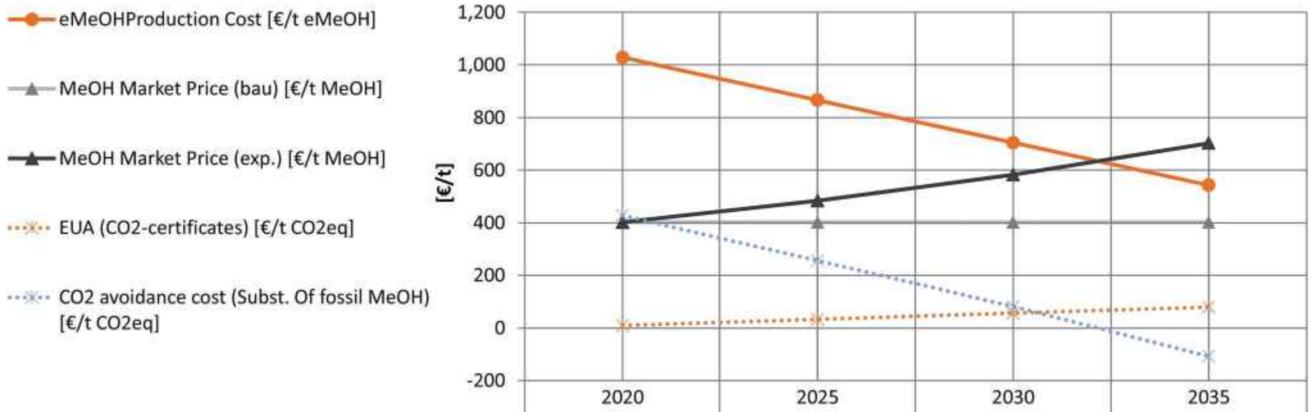
** To be reported in a forthcoming article.

†† 41 kg of CO_2 are vented during the synthesis step. Therefore 1388-41 = 1347 kg of CO_2 per t(eMeOH) are 'bound' in the product.

‡‡ The cradle-to-grave assessment does not consider impacts resulting from transportation of the produced methanol and any recycling of the infrastructure. However it is assumed that impacts resulting from these phases in the eMeOH and the fMeOH are in a comparable range.

§§ GWP_{100a}, method CML 2001, allocation cut-off.

¶¶ Original ecoinvent activity methanol production [GLO]: GWP_{100a}: 52 545 $kg(CO_{2eq})$; method CML 2001, allocation cut-off.



	2020	2025	2030	2035
eMeOHProduction Cost [€/t eMeOH]	1028	866	705	543
MeOH Market Price (bau) [€/t MeOH]	402	402	402	402
MeOH Market Price (exp.) [€/t MeOH]	402	484	583	703
EUA (CO2-certificates) [€/t CO2eq]	10	33	57	80
CO2 avoidance cost (Subst. Of fossil MeOH) [€/t CO2eq]	428	256	82	-107

Fig. 8 Estimation for the future development of green methanol production cost and CO_2 avoidance cost in the case of fossil methanol substitution.

emitted CO_2 significantly higher prices than the recent prices envisioned by the European Emission Trading Scheme (EU-ETS) with CO_2-certificate prices of *ca.* 5€ $t(CO_{2eq})^{-1}$ for the last 12 months (Sept 16 to Aug 17).||||

Future development of methanol production cost & the corresponding CO_2 avoidance cost

For future development of the parameters until 2035 we assumed the development of some central sensitive parameters. The initial point for this assessment sets scenario 5A. Parameters are set considering in-house studies for the decrease of large-scale PEMEL specific cost (2035 @ 300€ $kW_{inst}{}^{-1}$), a significant increase in CO_2 certificate prices (2035 @ 80€ $t(CO_2)^{-1}$),[78] and a further decrease in the levelised cost of renewable electricity in general and PV-electricity in particular (2035 @ 1.8 ct€ per kWh_{el}).[72–75] The resulting predictions in green methanol production costs and the corresponding CO_2 avoidance costs are compared with a constant (business as usual, 'bau') and the exponential forward projection of the methanol market prices ('exp') based on the Methanex European posted contract price for the last 15 years.[70]

Fig. 8 contrasts the resulting development of eMeOH with an increasing methanol market price, demonstrating a prediction for market parity in *ca.* the year 2032. At around the same time the CO_2 avoidance cost will turn negative (based on the assumptions made regarding investment and operational costs) which can be interpreted as the market offering an economic incentive to the industry for utilising their CO_2 emissions instead of emitting them. These points of time fit the published results for the development of the market demand for electrolyser technology showing a clear market launch from the year 2032.[78,79] Furthermore a future increase of the GWP for fMeOH production could be assumed due to the necessity of a more intensive exploration of fossil resources and longer transport distances. This would have an additional lowering effect on CO_2 avoidance cost, which was not considered here.

|||| EU CO_2 Emission Allowances (Sept 16 to Aug 17) according to the European Energy Exchange.

Conclusions

The presented evaluation shows that the economic feasibility of a specific PtL process (*i.e.* for eMeOH) strongly depends on electricity and H_2 production cost, CO_2 cost (also reflecting any introduced carbon taxes), specific electrolyser cost and the possible dynamics of the methanol reactor (having an impact on the necessity and size of H_2 storage). Furthermore, indirect parameters such as carbon taxes will have an impact on the willingness of the market to pay for eMeOH (and derived sustainable chemicals) and as such can be considered desirable.

Under the evaluated process conditions in this study, the production of eMeOH in Germany is currently not economically competitive, if one presupposes the competition with fossil based large capacity methanol production and its current low price. The investment and operational costs are currently inhibitory and therefore, the eMeOH production price exceeds the expected revenues. Currently, conventional large scale methanol production based on CH_4 reforming has a very low price due to very inexpensive fossil supply (*e.g.* from increased fracking in the USA and increased production of fMeOH from coal in China). A high degree of capacity utilisation is advantageous and favourable for low eMeOH production cost. Therefore maximised plant operation (*e.g.* in terms of hours) is also to be highlighted as an important factor in achieving eMeOH economic feasibility.

The presented sensitivity study demonstrates that a decrease in the specific investment costs of the PEMEL leads to a major economic efficiency improvement for the described PtM process. Heading towards the target value for specific electrolyser investment (target value: 440€ kW^{-1}) is in general an important step towards the economic feasibility of PtL-systems. The low-emission eMeOH production scenario (wind energy driven) had a higher production cost due to the additional requirement for H_2 storage (*i.e.* 2^{nd} largest share of investment costs). A reduction in specific H_2 storage size and costs would therefore be beneficial. The possibility of underground H_2 storage in salt caverns (*e.g.* in northern Germany) depends on local conditions but offers a promising way for mitigating the strong interlinkage between H_2 storage volume and its associated investment costs.[64] In the long-term it will be necessary to offer possibilities for a more dynamic operation of the synthesis step to reduce the storage demand for H_2.

To successfully introduce any PtL process, it is initially important to think of potential synergies: the methanol production of Carbon Recycling International is underpinned by low-cost geothermal electricity and CO_2 from a geothermal power plant (located adjacent to the plant). Thyssenkrupp AG is aiming to significantly cut their CO_2 emissions by utilising the waste gases from steel production (coupled with additional H_2 production) to generate side streams of fuels and chemicals.[80] The presented PtL scenarios are all on a small-scale compared to fossil based plants on the Mt-scale. Future large-scale PtL-plants, coupled with existing chemical or heavy industry, would also have a number of advantages: instant access to low-cost grid electricity, availability of (highly concentrated) CO_2 streams (which still need purification) or unused H_2 in off-gases, if necessary access to HT-process heat/steam and last but not least, the vast cost-reducing effect of a PtL plant scale-up.

Regarding policy instruments to support the introduction of economically viable PtL schemes, amendment of general policy frameworks and taxation systems (*e.g.* special grid fees for energy storage and grid-supporting technologies, and an improved European Emission Trading System) would be beneficial. A modified taxation system for CO_2 emissions could generate a CO_2 certificate price and market conditions appropriate for an industrial business case for CCU. Another approach could be a tax reduction for "renewable fuels". The gradual reduction of fossil fuel subsidies would also aid in the long term attractiveness of PtM schemes, particularly as the amount of the RE share in the electric grid increases. The proposed 'double counting'*** of 2^{nd} generation biofuels according to the revision (iLUC Directive 2015/1513/EC[81]) of the RE directive RED (2009/28/EC[82]) is a first step when also including CO_2-based fuels. Regarding fossil-based production, environmental costs and impacts are generally not internalised and therefore factoring environmental burdens would lead to a higher price of fMeOH. One example is the introduced foundation for climate protection and CO_2-compensation (Foundation for Climate Protection and Carbon Offset (Stiftung Klimaschutz und CO_2-Kompensation, Klik)),[83] following the revision of Swiss CO_2-law. It commits producers and distributors of fossil fuels to provide compensation for the environmental impacts of their products and in turn provides investment in funding programs focusing on Swiss GHG emission reduction.

The presented analysis highlights that the CO_2 avoidance costs for the evaluated wind electricity based scenarios are currently in the range of 421–444€ $t(CO_{2eq})^{-1}$ avoided and strongly depend on the process and market conditions within the selected scenarios. The process conditions (electrolyser efficiency, synthesis pressure, source of CO_2, *etc.*) not only influence eMeOH production cost but also the results for the CO_{2eq} footprint and thus the CO_2 avoidance cost. It has been shown that for future technological optimisation of some CCU key components (resulting in the improvement of central economic process parameters) even for cost intensive 100% RE based set-ups the green methanol production cost can be strongly decreased (543€ $t(eMeOH)^{-1}$, −47%, scenario 5A) within the next two decades bringing market competitiveness with fossil based methanol within the realms of possibility. In the same time frame the CO_2 avoidance cost will feature a clear drop (−124%) resulting in negative values and through this provide an incentive for industries to reinterpret their CO_2 emissions from waste to feedstock.

It is important to consider that the CO_2 avoidance cost should be used only as one key-criterion for the selection among the variety of possible CCU processes.[84] In combination with the specific CO_2 avoidance potential of each PtL-/CCU-technology, the most cost- and eco-efficient routes should therefore be selected. In this context, a detailed Life Cycle Assessment (LCA) is mandatory to identify the specific CO_2 avoidance cost and potential. Positively, the analysed technology will be supported by (and also support) the rapidly growing and intended expansion of RE (*e.g.* in Germany and the EU in general) over the next few decades. This growth will necessitate consideration of technologies such as PtL, further supported in terms of economic readiness by the ever reducing RE price per ct€ per kWh. PtX technologies will be one important pillar of the integrated-energy concept ('sector-coupling') within the European markets of electricity, heat and mobility. Further postponement of integrating renewable energies in the mobility sector and chemical industries will further impede the climate protection programs.[79]

Our results demonstrate that off-grid wind electricity is promising for eMeOH production, but in the case of an isolated wind energy system and without large H_2 storage it cannot ensure a high degree of capacity utilisation. For realisation of an off-grid renewable PtL process, the coupling of wind power with photovoltaic or solar thermal electricity generation and/or additional baseload supplies (*e.g.* biogas plants or combined heat and power plants based on biomass, offering also a biogenic CO_2 point source) would lead to higher capacity utilisation and a reduced storage demand. Thinking globally,

*** Double counting of advanced/second generation biofuels: regarding the extension of the Renewable Energy Directive (RED) 2009/28/EC (28.04.2015) member States must ensure that 10% of the final energy consumption in the transport sector is provided by renewable sources. The share provided with advanced/second and/or third generation biofuels is double weighted.

relocation to regions with higher solar irradiance (*e.g.* the Maghreb region, Australia or south western parts of North America) and/or reliable wind power (*e.g.* Chile, Peru, South Africa, or Scandinavia) offers the possibility of a low cost RE supply. Low cost RE electricity of around 2.5 ct€ per kWh_{el} (reflecting recent price bids for PV electricity[72–75]) and a higher degree of capacity utilisation due to a less fluctuating RE potential MPC of ~500€ $t(eMeOH)^{-1}$ and below are in a realistic range. Regions with a current and prospectively low RE production cost provide opportunities for the further development of a business case for PtL (and PtX) technology within the coming decade. Further installation of pilot plants and the associated operational experiences, coupled with expected economies of scale, will lay a path to improved PtL economics, even in countries where RE electricity costs are currently prohibitive.

Conflicts of interest

There are no conflicts to declare.

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Comparative well-to-wheel life cycle assessment of OME_{3-5} synfuel production *via* the power-to-liquid pathway†

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Oxymethylene Dimethyl Ethers (OMEs) are promising diesel fuel alternatives and interesting solvents for various industrial applications. In this report, a well-to-wheel life cycle assessment of short OME oligomers as produced *via* a Power-to-Liquid (PtL) pathway has been conducted. Variations in electricity and carbon dioxide supply as well as the hardware demand for the PtL plant components (*e.g.* PEM water electrolysis, carbon capturing, and 36 kta OME plant capacity) have been considered. Conventional diesel fuel is used as the comparative benchmark. In scenarios with a high share of renewable electricity well-to-wheel greenhouse gas emission for OME_{3-5} fuel is advantageous compared to fossil diesel. For the best case, well-to-wheel greenhouse gas emissions can be reduced by 86%, corresponding to 29 g(CO_{2eq}) km^{-1} (OME_{3-5}-fuel) compared to 209 g(CO_{2eq}) km^{-1} (diesel fuel). However, these results are highly sensitive to the applied method with regard to system multifunctionality. A sensitivity analysis indicates that input electricity at ~50 g(CO_{2eq}) kWh_{el}^{-1} enables well-to-wheel greenhouse gas emissions of <100 g(CO_{2eq}) km^{-1}. For other environmental impact categories, acidification, eutrophication, respiratory effects, photochemical ozone creation and resource depletion exceed significantly the fossil fuel reference. A high share of these impacts can be assigned to electricity production, either through direct electricity consumption in the PtL system or during upstream production of hardware components. The presented results and discussion demonstrate the necessity for global defossilisation including material efficient manufacturing of renewable energy plants which remains mandatory for synfuel production addressing a wide range of environmental impact categories. Furthermore, PtL production concerning well-to-wheel greenhouse gas emissions could be beneficial even in Germany if dedicated renewable energy capacities are considered. However, operation of large-scale PtL plants will predominantly be conducted in countries with high renewable energy potential, resulting in low levelized cost of electricity and high full load hours.

Introduction

There is tremendous pressure to limit the global temperature increase to 1.5 °C, which requires intensive defossilisation efforts by the international community.[1] In Germany especially the mobility sector stays way behind the sector specific targets which were set up in order to achieve the self-imposed national greenhouse gas (GHG) reduction targets.[2,3] Additionally, we face controversial discussions about the impact and handling of high road traffic related local emissions, especially particulate matter (PM) and nitrogen oxides (NO_x). Based on renewable energy (RE), carbon dioxide (CO_2) capture and its downstream catalytic conversion with renewable hydrogen (H_2), the Power-to-Liquid (PtL) approach to chemical and fuel production can support defossilisation and enable integration of the energy, chemical and mobility sectors. PtL, as part of the Power-to-X (PtX) process schemes, is an important element of sector-coupling, enabling the infusion of RE into the primary energy demands of our global economies. The electrification of central end uses such as heating and road transport will lead to a significant rise of electricity in the final energy consumption from 19% today to 29% by 2050.[4] In particular the electrification

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of mobility applications is expected to increase from <1% in 2016 to 27% in 2050. With regard to urban transport the European Union targets a 50% reduction in 2030 and a complete phase out of conventionally (fossil) fuelled cars.[5] While battery electric vehicles are favourable for shorter driving distances (*i.e.* <300 km) long hauls or heavy road transports can in terms of life cycle GHG emissions be more sustainable when fuelled by hydrogen fuel cells or synthetic fuels.[6] The Deutsche Energieagentur (DENA) assessed the potential of electricity-based fuels for low-emission transport in the EU. Even for 2050-scenarios favouring electric powertrains, more than 49% of the total fuel demand of all mobility applications will be met by electricity based liquid fuels.[7] Studies with a focus on the future German energy system aiming at a 95% GHG reduction quantify a total necessary electricity provision of 129 TW h_{el} for PtL for its application in sector-coupling and future mobility[8] (gross electricity generation in Germany in 2018: 649 TW h_{el}).[9]

In addition to reduction of life cycle GHG emissions, local emissions of PM and NO_x shift into the focus of political debate and legislation. In the context of new mobility fuels, short chain oligomeric Oxymethylene Dimethyl Ethers (denoted as OMEs; molecular formula $H_3CO{-}(CH_2O)_n{-}CH_3$; where $n = 1$–5) can be produced from CO_2 and H_2 typically *via* methanol (CH_3OH).[10] OME_{3-5} are of interest as diesel additives or substitutes as they are non-hazardous, weakly corrosive, miscible with conventional diesel[11,12] and their combustion is almost free of PM.[13–17] Due to a high oxygen content (48 wt%)[18] and cetane number, OME_{3-5} mixtures have been blended with conventional diesel without modification of the internal combustion engine.[13,19,20] OMEs offer a high tolerance towards exhaust gas recirculation and hence can eliminate the PM–NO_x trade-off which inevitably occurs in the case of conventional long-chain diesel fuel.[13,21,22] Another perspective and a promising market for OMEs is their application as solvents, with OME_1 already established as an industrially applied solvent.

Currently, industrial OME_n production provides capacities of *ca.* 30–40 kta but is characterized by low overall process efficiency.[23] The production is based on CH_3OH traditionally synthesised *via* syn-gas obtained from steam-reforming of fossil energy carriers (*e.g.* methane). For the production of OME_{3-5} from a PtL basis, whilst economically feasible (as we have reported previously),[24] life cycle assessment (LCA) and associated ecological impacts have yet to be examined in detail, especially with regard to the utilisation phase (*e.g.* combustion). A holistic Well-to-Wheel (WtW) LCA is thus important to determine whether this energy carrier offers environmental advantages compared to fossil-based equivalents. In this regard and within the framework of our current research[24–27] this article addresses the following questions (*i.e.* the goal of the performed LCA):

→ Environmental efficiency of OME_{3-5}: what are the environmental impacts resulting from the production and utilisation of OME_{3-5} as a fuel? How does the synfuel perform in comparison to the production and utilisation of conventional fossil diesel fuel?

→ What are the systems most impacting life cycle phases and components in terms of environmental impact minimization?

Necessity for the environmental evaluation of OME_{3-5}

Thus far, reports in the literature regarding the LCA of OMEs have focused on either pure OME_{1-8} derived from forestry biomass with Canada as the geographical reference[28] or on the production of shorter chain OME_1 based on electrolytic H_2 applied in the form of OME_1–diesel-blend (35 vol% OME_1).[21] OME_1, commercially known as "Methylal", has a high vapor pressure, relatively lower specific volumetric energy and low flash point. These are drawbacks when blended with diesel fuel and when long-term storage in the current infrastructure is considered. Both previously reported LCAs indicated that at low blending rates (<35 vol% OME_1) soot emissions can be significantly reduced. The WtW GHG emissions can be reduced considerably when either forestry biomass or low-carbon electricity acts as the energy source for synthetic fuel production. A more detailed description of the addressed assessments is provided in the ESI (S1).†

Regarding testing of OME fuel in real internal combustion engines Avolio *et al.* conducted tests with different OME–diesel blends in different diesel engines.[29] Regarding life-cycle emissions it was stated that a 30% OME-content leads to an 18.5%-reduction in WtW CO_2-emissions 'under the premise of a sustainable production from renewable sources'. Further explanation of the assessment background for the WtW emissions was not included in the report.

Therefore and to the best of our knowledge there is currently no publicly available LCA of OME_{3-5} which is required to support further R&D, process optimisation and indeed policy decision making.

As it is a critical consideration, when conducting the ecological evaluation of sustainable fuels and chemicals, terminologies such as "CO_2- or environmentally-neutral" or even "carbon-negative" have to be handled carefully.[17,30–33] It is to be emphasised that none of the proposed future mobility options, if powered directly by electricity or by chemical energy carriers, will lead to CO_2-neutrality. As such in a WtW approach (*i.e.* including upstream impacts of fuel production), there will always be net-positive CO_2(equivalent) emissions (denoted as CO_{2eq}). Instead of discussing mobility concepts on the basis of Tank-to-Wheel system boundaries, it appears that WtW assessments should be handled as a fundamental prerequisite for environmental evaluation. It is also important to note that carbon emission reduction pathways only serve as temporal CO_2-storage mechanisms and aim when sourced from biogenic or atmospheric CO_2 at creating a highly integrated carbon cycle.

Thus, the Methodology section below describes the assessed product system and scenarios, the investigated OME synthesis route as well as the environmental indicators and the aspects of multifunctionality of the assessed PtL system.

Methodology for the life cycle assessment

The performed LCA was predominantly structured and conducted in compliance with ISO 14040:2009, ISO 14044:2006,[25,34,35] and recommendations of the European

Commission.[36–38] Synthesis process data are described in the "Theoretical background for the assessed OME_{3-5} synthesis" section. Umberto® NXT Universal LCA software was used for modelling and impact calculations. Background LCA data were sourced from the ecoinvent database (v.3.3), manufacturer specifications, published literature and in-house experience. For the applied ecoinvent background processes cut-off system models which build on economic allocation as the default methodology have been used.

Assessed product system, functional units and scenarios

The scale of the assessed PtL product system is based on the electricity production of a 100 MW_p RE park and it is designed for an annual production capacity of 36 kta of OME_{3-5}. In general it comprises nine main process steps (Fig. 1A): electrolytic H_2 production by proton exchange membrane water electrolysis (denoted as "PEM"), CO_2 capture from one of the three assessed CO_2 sources (*i.e.* biomethane, ammonia, and direct air capture), methanol synthesis with subsequent flash and distillation units, anhydrous dehydrogenation of methanol to formaldehyde followed by OME_n synthesis and the necessary distillation towards the target product OME_{3-5} (please see the section "Theoretical background for the assessed OME_{3-5} synthesis" for further details). Necessary (by-)product separation, recirculation, cooling and compression are part of the related processes of methanol- or OME_{3-5}-synthesis. To reduce the thermal energy demand heat integration has been performed. The OME_{3-5} product is then assumed to be distributed and utilised in a mid-size diesel-car (WtW system boundaries). All of the described life cycle phases require process energies (electricity and steam), process and cooling water, parts and materials for plants and machinery construction, as well as maintenance and fuel transportation. The life cycle inventory provides further description of the single process steps.[25]

To meet the goal of a comparative LCA study the investigated PtL OME production and the reference system need to fulfill the same primary function. Therefore a driving distance of 1 km is chosen as the functional unit (FU) for the WtW system boundaries.

Three main scenarios allow for variation of technology parameters and the applied electricity (Fig. 1B). They are characterized by a high to low GHG intensity of the applied electricity, a variation of the PEM efficiency and stack lifetime and the supply of thermal energy for the synthesis steps.

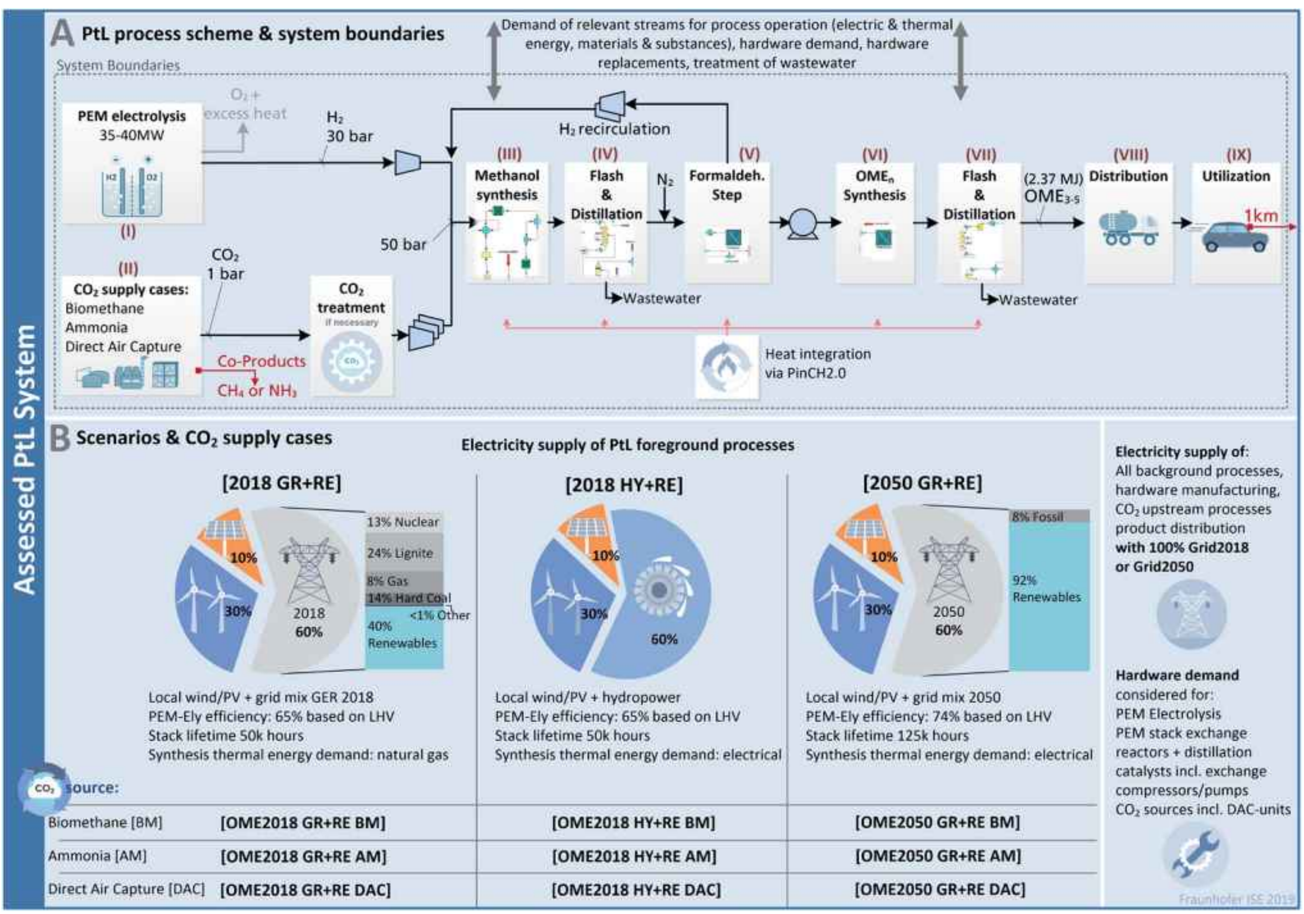

Fig. 1 A) Assessed PtL product system grouped into the relevant process steps. (B) The three technology scenarios varying in electricity supply, PEM efficiency, PEM stack lifetime and thermal energy supply. CO_2 is supplied from three sources: biomethane, ammonia and direct air capture. The resulting designation of the scenarios is indicated in square brackets.

The CO_2 supply cases consider a biogas upgrading plant separating mainly CO_2 from biomethane [BM], an ammonia production facility [AM] and a direct air capturing technology [DAC]. The designation of the resulting nine assessed combinations is indicated in square brackets.

Indicators for the environmental impacts

PtL (and CCU) systems are designed for the integration of the carbon cycle and hence the mitigation of fossil CO_2 emissions. This is why most discussions on PtL focus on the specific systems' Global warming potential. However, a holistic LCA shall aspire to cover as well further impact categories to disclose fully the potential environmental benefits/disadvantages. The selected impact categories in this study are climate change, GWP 100a [kg CO_{2eq}]; resources (minerals, fossils and renewables) [kg Sb_{eq}]; freshwater and terrestrial acidification [mol H_{eq}^{+}]; freshwater eutrophication [kg P_{eq}]; marine eutrophication [kg N_{eq}]; terrestrial eutrophication [mol N_{eq}]; ozone layer depletion [kg CFC-11_{eq}]; respiratory effects, inorganics [kg $PM2.5_{eq}$]; photochemical ozone creation [kg $ethylene_{eq}$]; cumulative energy demand, total [MJ_{eq}]; and cumulative energy demand, non-renewable [MJ_{eq}]. The ILCD Handbook "Framework and requirements for LCIA models and indicators" provides general information on these categories.[39]

Solving of multifunctionality

A comprehensive definition of multifunctionality in the context of CCU can be found in the ESI (S2)† together with references to relevant literature. A description of the avoided burden methodology applied in this study is also provided.

In this study system boundaries have been expanded to include the source of CO_2 (Fig. 2A). Besides the primary FU of 1 km driving distance, this leads to the inclusion of an additional functionality – *i.e.* the production of either biomethane or ammonia. Since the focus is on the production of OME_{3-5} or fossil diesel fuel and driving over 1 km, these additional functions are designated as "co-products". For multifunctional CO_2 supply cases, biomethane and ammonia life cycle impact results are presented on the basis of the avoided burden approach, sometimes referred to as substitution. This represents one solution for multifunctionality when the alternative approaches of subdivision and system expansion are either not applicable or considered as insufficient for the presentation of results.[40]

Avoided burden presumes that co-product generation in the coupled product system enables the substitution of a conventionally produced co-product. The respective impact of the avoided conventional production is credited (subtracted) to the coupled product system. However, impact crediting can for some cases even lead to negative overall results. Negative results can be mistaken as a reversal of impacts; *i.e.* if operated the respective product system is assumed to lead to an improvement of environmental conditions. A correct interpretation for negative results is that the total impact of the coupled product system is smaller than the total impact of the avoided conventional production of the single co-product. This leads to a net benefit even though the coupled product system still has an environmental impact. The net benefit is valid as long as the market for the co-product is not saturated.[36,40]

It is important to note that avoided burden is valid as long as the substitution of conventional production can be assured. The latter for example can be the case for carbon capture from already existing CO_2 sources or if the co-production enables a reduced production elsewhere. However, an ever increasing

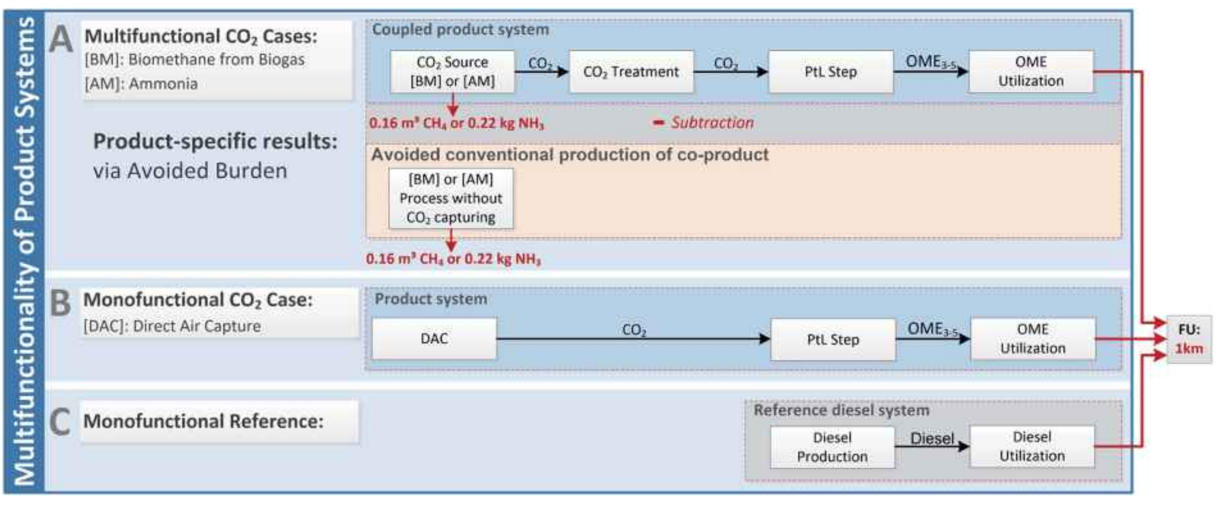

Fig. 2 A) The assessed product systems with a CO_2-supply based on biomethane [BM] or ammonia [AM] are multifunctional since they are providing an additional function (biomethane or ammonia) besides the main function (1 km driving distance). The avoided burden methodology subtracts a respective amount of avoided conventional production from the expanded system. By this, the obtained product specific results (FU: impact per km) can be compared to the other CO_2 cases and the reference diesel system. (B) In the case of a CO_2-supply from a Direct-Air-Capture [DAC] plant the sole function of the product system is a driving distance of 1 km. (C) This as well applies to the monofunctional reference diesel system. (B and C) The hereby obtained product specific results (FU: impact per km) can be compared to both the CO_2 case [DAC] and the reference diesel system.

production of the co-product can lead to saturation of the respective market. For this case, results based on the avoided burden approach might be misleading since the substitution cannot be assured. As recommended by the ISO 14044 the results for the expanded systems are included in the ESI (S7).†

For the monofunctional CO_2 case [DAC] (Fig. 2B) and the diesel reference process (Fig. 2C) no avoided burden needs to be credited since these product systems are already product-specific with a FU of 1 km.

Theoretical background for the assessed OME_{3-5} synthesis

The LCA of OME_{3-5} synthesis conducted in this paper is based on a synthesis process using methanol and anhydrous formaldehyde as described and economically assessed by Ouda *et al.*[10,24] In this work the described process chain, formerly based on fossil methanol, was extended to include the preceding synthesis of CO_2-based methanol, the capturing of CO_2 and the electrolytic H_2 production. The OME_{3-5} product mixture consists of 39 wt% OME_3, 34 wt% OME_4 and 27 wt% OME_5 resulting in a heating value (19.031 MJ_{LHV} per kg(OME_{3-5})) of 44% compared to that of conventional diesel fuel (42.791 MJ_{LHV} per kg(diesel)).The process was simulated using the simulation software CHEMCAD® coupled with Matlab® *via* a VBA script to describe the process reactors.[24] A heat integration process has been performed using the software PinCH2.0.[41] Here a heat exchanger network has been developed to maximize the process heat recovery while considering occurring investment costs. Afterwards the heat exchanger network was implemented in CHEMCAD®. Combining the methanol synthesis sub-plant with the formaldehyde and the OME sub-plants has been beneficial for the overall internal energy recovery. A detailed description of the synthesis steps and a simplified process flow diagram are provided in the ESI (S3).†

Inventory for the assessed OME_{3-5} system

The order of the inventory is organised in analogy to the process scheme. A detailed tabular summary of the life cycle inventory (LCI) and complementing descriptions are included in the ESI (S5).† Since the hardware demand of the PtL components is included it was important to assume a technical lifetime for the overall system as well as exchange rates for the PEM stacks and catalysts. If not mentioned otherwise in the following description of the LCI a lifetime of 20 years has been assumed for H_2 production, CO_2 sourcing and the synthesis steps, including compression and distillation.

Electricity

Three different scenarios have been selected (compare with Fig. 1B) which combine steady-state electricity provision from grid mixes or hydropower with fluctuating RE. A complementing detailed description of the derivation of the applied electricity mixes is given in the ESI (S4).† The electricity provision scenarios are described as:

• **[2018 GR + RE].** Consisting of 60% grid mix in Germany, 2018, plus 40% local RE. The 40% share of RE is based on load profiles of local wind and photovoltaic (PV) plants in the south of Germany. The grid data for 2018 are based on published data of the publicly accessible ISE energy charts.[42]

• **[2050 GR + RE].** Consisting of 60% grid electricity for a predicted 2050 mix in Germany plus 40% local RE (as described above). For an estimation of the 2050 grid electricity mix and its resulting footprint the REMod-D model developed at Fraunhofer ISE has been used.[43–45]

• **[2018 HY + RE].** Consisting of 60% hydropower (run-of-river) and 40% local RE (as described above). The ecoinvent process "hydro, run-of-river [DE]" is used as the background process. When it comes to using limited forms of electricity generation such as the case for hydropower in Germany the argument for the PtL plants' additional electricity demand is justified. It can be argued that in the case of a large-scale PtL plant in Germany an electricity supply from dedicated hydroelectric power plants remains unlikely. However, the [2018 HY + RE] scenario is included to provide the estimation for PtL scenarios where low-carbon electricity is supplied as is already the case for anticipated pilot-projects in Scandinavia.[46–48] By now, hydroelectricity provides the largest share of electricity from all RE sources within the EU member-states.

The electricity demand of the background processes such as distribution or production processes of hardware materials is fulfilled by the grid electricity mix defined by the scenarios (year 2018 or 2050). This is justified by the assumption that these external process steps cannot be influenced by the PtL process operator and any decisions promoting RE.

It is indeed important for Power-to-X systems powered by a high share of PV and wind electricity (*i.e.* without direct CO_2 emissions) to account as well for the indirect emissions during their production processes. The upstream emissions of RE plants can on the one hand be influenced by the RE plant's capacity utilization or, on the other, heavily influenced by the applied source of electricity for the RE plant production processes. For example a PV module processed in a factory which in turn is powered by an electricity mix featuring high shares of fossil based energy generation will as well show higher (indirect) GHG emissions per kWh_{el}-produced. In contrast, a PV module from 100% RE-powered factory potentially enables lower GHG emissions per kWh_{el}-produced. Therefore in the section discussing results we will analyse the source for specific life cycle impacts and trace them to their initial "causer".

CO_2 sourcing

The three selected CO_2 sources mirror the capture of atmospheric or fossil CO_2 and cover a PtL feed demand of 227.6 t(CO_2) d^{-1}. For captured atmospheric CO_2, the feedstock has already been part of the atmosphere before its re-emission to the atmosphere during product utilisation. Hence for a WtW assessment it can be assumed that the same amount of CO_2 removed from the atmosphere will be released to the atmosphere at any point of the life cycle. Indeed that does not mean that 'feedstock' atmospheric CO_2 can be accounted with zero burden since its upstream technology-based provision causes indirect impacts. Regarding the CO_2 feed demand of a PtL fuel production it should be noted that it will always be higher than the stoichiometric CO_2 formation during PtL fuel utilization. Part of the feed CO_2 is lost in the form of C-containing purge gases and waste streams and not bound in the synfuel. Thus for environmental evaluation of synfuel production it is important to consider the full CO_2 demand for correct impact assessment of CO_2 capturing, purification and compression.

For the supply case 'Biomethane', CO_2 is assumed to be supplied from a biogas upgrading plant used for the feed-in of biomethane to the natural gas grid. For the initial production of biogas from biomass and necessary materials and hardware demand the ecoinvent dataset "biogas production from grass [CH]" was modified and adjusted to average substrate feeds for the German market.[25,49] A CO_2 content of ~44 vol%, resp. 0.87 kg(CO_2) Nm^{-3} (biogas), was assumed.[50] Biogas upgrading includes desulphurisation to reduce H_2S content to >500 ppm. In order to protect and improve the lifetime of the methanol synthesis catalyst an additional fine-desulphurisation step has been considered with a final H_2S content below 5 ppm. A detailed description including the process parameters applied for the impact assessment is provided in the ESI (S5 – CO_2 sourcing).†

With the supply of biogenic CO_2, the biogas upgrading plant delivers two products: biomethane and feedstock CO_2, thus exhibiting multifunctionality. To obtain a product-specific result (FU = 1 km of driving) the respective amount of produced biomethane is credited (avoided burden approach): a driving distance of 1 km necessitates an upstream provision of 0.27 kg CO_2 which in turn can be captured from 0.16 Nm^3 CH_4. Hence the avoided burden is defined by a conventional biomethane pathway producing an equivalent amount of CH_4.

For the supply case 'Ammonia', data are based on the ecoinvent dataset "ammonia production, steam reforming, liquid [RER]".[51] The process has been edited as the original ecoinvent process assumes 1.23 kg of CO_2 for the downstream production of urea which is not listed as emission in the original dataset.[52,53] Thus this amount is assumed to be available for synfuel production at ambient pressure. Due to the high purity of the CO_2 desulphurisation is considered unnecessary. For the avoided burden approach the FU of 1 km driving results in 0.22 kg NH_3 as the co-product. A conventional ammonia production producing an equivalent amount without CO_2 capturing is credited. More information on ammonia as the CO_2 source is included in the ESI (S5 – CO_2 sourcing).†

For the monofunctional supply case 'Direct Air Capture', CO_2 is sourced directly from the atmosphere. Here thermal and electrical energy demands are considered as well as the hardware demand for DAC units. For the impact assessment either the available exhaust (burden free) heat or the burning of natural gas is assumed. Details on considered energy demands as well as hardware specification are included in the ESI.†

All three CO_2 sources including their upstream processing are assumed to be supplied by either the 2018 electricity grid mix ([2018 GR + RE]; [2018 HY + RE]) or the 2050 electricity grid mix ([2050 GR + RE]). Transportation and related losses for the CO_2-feedstock provision are neglected following the assumption that the CO_2 sources are located nearby the OME plant.

H_2 production

PEM water electrolysis is selected for electrolytic H_2 production. PEM technology has not reached the state of year-long operational experience as is the case for alkaline electrolysis (AEL). However PEM systems offer specific advantages when placed in the context of fluctuating RE production and PtX-concepts: they offer faster start-up (cold-start) and response times than AEL, higher current densities, allow for a higher operational pressure and therefore potentially reduce H_2 compression demand for downstream synthesis steps.[54,55] Today the investment cost for PEM electrolysis systems still exceeds that of AEL systems. However, a strong investment cost reduction and an increase of stack lifetime are expected in the next two decades enabling an alignment with the values for AEL systems.[54–57]

Details regarding the PEM system's parameters are listed in Table 1. The PEM system for our LCA is based on the data for a 5 MW_{el} PEM water electrolyser system comprising 5 × 1 MW_{el} stacks. Since the H_2 production capacity is pre-set by the PtL plants' H_2 demand the total number of 5 MW_{el} PEM systems is dependent on the assumed PEM system efficiency defined in the scenarios. For the 2050 scenario a forward projection of the technological development can be assumed leading to a considerably reduced specific electricity demand. The values are based on a recent sector survey including manufacturer estimations for future electrolysis system performances depending on the system size.[55] The assumed PEM system efficiencies have been validated by further comparing to published measured or simulated efficiencies.[58–61] Electricity is provided at high voltage, transformed to medium voltage and converted into direct voltage. Deionised water input and oxygen output were considered using stoichiometric calculation and in compliance with literature data. Oxygen is vented and not considered as a valuable product for this study. Cooling water demand is also included.[62]

Hardware data for the 5 MW_{el} PEM systems are based mainly on the primary data of Fraunhofer ISE.[25,63] To account for stack longevity the 2018 scenario assumes a stack lifetime of 50k h after which a complete replacement is necessary. For reasons of simplicity any partial recycling of stack components at the end of their lifetime is neglected. The stack hardware data comprise the complete membrane electrode assembly (MEA) consisting of Pt-loaded cathodes, IrO_2-loaded anodes, Cu current collectors, Ti-bipolar plates, Nafion® membranes, Ti-current collectors and device frames and sealing. The stack endplates are excluded from replacement. For the two 2050 scenarios a significant increase of stack lifetime to 125k h is assumed representing the median value obtained from statements in sector surveys.[55] Secondary data for power electronics are derived from the ecoinvent "fuel cell production, polymer electrolyte membrane, 2 kW electrical, future", which is a source of uncertainties due to the high difference in installed capacities. Additionally an 800 m^2 building hall and three 40-foot intermodal shipping containers have been considered based on presentations and publications from industry.[59,64,65] Due to insufficient data availability a water–gas separator and a further H_2 purification (De-Oxo) have been excluded from the hardware demand.

Methanol & OME_{3-5} synthesis steps

Process data of the two synthesis steps as well as related compression, pumps and distillation units are based on process simulation with CHEMCAD® and heat integration *via* PinCH2.0. The synthesis plant capacity is 36 kt per a(OME_{3-5}). Process data include the electricity for compressors and pumps, heat for the dehydrogenation of methanol to formaldehyde and steam for the necessary 5 distillation columns. Thermal energy supply is provided by either natural gas (GRID2018 + RE) or by the respective electricity mix (GRID2050 + RE, HYDRO2018). Material data consider catalysts, reactors, compressors and pumps. The utilities, ancillaries, and offsite infrastructure demand are estimated by means of a standard ecoinvent process. The ESI (S5 – Methanol synthesis and distillation)† provides detailed information on specific energy and material demands as well as additional information on the catalysts assumed for the assessment.

Distribution and utilisation of OME_{3-5}

The final OME_{3-5} product is assumed to be distributed to the point of utilisation. Since the form of distribution is very dependent on geographical and case specific assumptions, a distribution mix including comparable shares of lorry, train and ship transportation is assumed. The necessary transportation distance is assumed to be 400 km. The differing energy densities of diesel and OME_{3-5} result in a higher OME_{3-5} distribution demand.

Utilisation in a medium size passenger car fuelled by OME_{3-5} was assumed in the utilisation phase. Due to different heating values of diesel and OME_{3-5}, the engine has a higher mass flow in the case of OME fuel. Empirical data show that the injection demand of diesel is *ca.* 46% of that of OME_{3-5} which corresponds to the ratio of heating values. However, OME fuel can show 1–3% efficiency improvement.[20,66] Hence the OME_{3-5} fuel consumption equals:[25]

$$m_{\mathrm{OME}} = m_{\mathrm{diesel}} \frac{\mathrm{LHV}_{\mathrm{diesel}}}{\mathrm{LHV}_{\mathrm{OME}_{3-5}}} (1 - \Delta\eta)$$

m_{diesel} – mass of diesel fuel [kg]. $\mathrm{LHV}_{\mathrm{diesel}}$ – lower heating value of diesel = 42.791 MJ kg^{-1}.[67] $\mathrm{LHV}_{\mathrm{OME}_{3-5}}$ – lower heating value of OME_{3-5} = 19.031 MJ kg^{-1}.[68,69] $\Delta\eta$ – efficiency increase for OME *vs.* diesel = 2%.[20,66]

The specific energy demand of the passenger car of 237 MJ or 12.5 kg OME_{3-5} per 100 km is based on the EU-wide transport model TREMOVE of the European Union.[70] This specific energy demand equals a real-world fuel consumption of 11.7 and 6.6 litres of OME_{3-5} and diesel fuel, respectively, for a mid- to upper-size passenger car. Wietschel *et al.* 2019 assessed a diesel fuel consumption of 5.7 and 8.2 litres for a mid- and upper size car, respectively.[71] The German federal environmental agency (UBA) quantifies the average fuel consumption of cars in Germany to 7.4 litres.[72] The assumption we make regarding the specific energy demand affects both fuel concepts equally. The ecoinvent process “transport, passenger car, medium size, diesel EURO 5” has been chosen. The environmental impacts resulting from car manufacturing are excluded since the fuel production and utilisation related emissions are of major interest in this assessment. Tire, brake and road wear emissions are also excluded since they are assumed to be independent of the used fuel. The detailed compilation for the emissions resulting from the utilisation of OME_{3-5} in an internal combustion engine is provided in the ESI (S5 – OME_{3-5} utilization).†

Diesel reference process

The diesel reference process has been selected based on secondary data obtained from the ecoinvent database; *i.e.* the “transport, passenger car, medium size, diesel, EURO 5” dataset has been selected for the impact assessment. Ecoinvent classifies vehicles with a gross weight of 1.6 t and an engine displacement of 1.4–2.0 L as “medium size” passenger cars. The diesel fuel consumption adds up to 0.055 kg diesel per km. Upstream processes of low-sulphur diesel production, petroleum refinery operation and petroleum extraction are included in the reference system boundaries. Electricity consumptions of the diesel production and the petroleum refinery operation have been adapted to the respective electricity mix of either 2018 ([2018 GR + RE], [2018 HY + RE]) or 2050 ([2050 GR + RE]). However, the results for the diesel product system showed that a variation of the electricity mix only has a negligible impact on

Table 1 PEM electrolysis operating parameters

	2018 GR + RE	2018 HY + RE	2050 GR + RE
Production capacity (t(H_2) d^{-1})	18.7	18.7	18.7
Electricity demand system (kWh_{el}/Nm^3 (H_2))	4.6	4.6	4.1
Efficiency system ($\%_{LHV,\ H_2}$)	65	65	74
Efficiency rectifier (%)	98	98	98
Installed capacity (MW_{el})	40	40	35
Deionised water demand (t(H_2O_{DI}) per t(H_2))	8.92	8.92	8.92
Cooling water demand (t($H_2O_{cooling}$) per t(H_2))	1.62	1.62	1.62
Oxygen output, vented (t(O_2) per t(H_2))	7.90	7.90	7.90
Lifetime PEM stacks (1000 hours)	50	50	125

the total GHG emissions (<0.1%). For reasons of a clear presentation the results of the OME_{3-5} product systems are solely compared to the results of the diesel product system based on the 2050 grid electricity mix. Technological improvements for 2050 in the case of fossil diesel production have not been considered. It can be assumed that these conventional processes are established and mature. As for OME_{3-5} production, emissions from the manufacturing of the car as well as tire, brake and road wear emissions have been excluded from the assessment.

Environmental impacts of OME_{3-5} as synfuel – *via* the avoided burden approach

To answer the main research questions (environmental impacts of OME_{3-5} production and utilisation compared to conventional fossil diesel fuel) the life cycle impact assessment results are first discussed for the global warming potential (GWP_{100}). Subsequently, additional assessed impact categories will be addressed to disclose a more complete picture of the environmental implications. A sensitivity analysis regarding the footprint of supplied electricity as well as the PEM system efficiency concludes the section on results. The whole section on results is based on and valid for the avoided burden approach (compare with the section "Solving of multifunctionality"). The life cycle impact assessment results for the expanded system are included in the ESI (S7 – Life cycle impact assessment results for system expansion).†

Global warming potential

Fig. 3 presents the product specific GWP results (expressed as GHG emissions $g(CO_{2eq})\ km^{-1}$; overall impact as green bars). The product specific FU of 1 km allows the comparison of all CO_2 cases and the diesel reference. For the CO_2 cases Biomethane and Ammonia, the avoided burden approach has been applied and a conventional production of the co-product is credited to the OME product system (*i.e.* a negative value in light blue). For the CO_2 cases Biomethane and Direct Air Capture (*i.e.* atmospheric CO_2 sources), the final exhaust pipe CO_2 emissions are considered without GWP (compare with the section CO_2 sourcing). By contrast, the fossil CO_2 case Ammonia and the reference diesel process show GWP during the utilisation phases (grey bar). In the following all three CO_2 sources based on the 2018 grid and RE mix [OME2018 GR + RE] will be discussed. Subsequently the results for the additional two electricity cases are analysed.

Case [OME2018 GR + RE]. The electricity mix consisting of 60% grid 2018 + 40% RE carries a GWP burden of 350 $g(CO_{2eq})\ kWh_{el}^{-1}$, with the highest contribution from lignite and hard coal based electricity production. The 40% share of local wind and PV production accounts for only 6% of the electricity's GWP. Regarding the WtW driving emissions, results clearly show that for all three CO_2 sources the assessed OME_{3-5} production pathway is not favourable in comparison to driving with conventional diesel fuel. The corresponding GHG emissions per km of driving distance with OME_{3-5} exceed those of driving with conventional diesel fuel by up to 263% for the worst case [OME2018 GR + RE DAC, natural gas as heat supply]. The calculated WtW emissions of 209 $g(CO_{2eq})\ km^{-1}$ for the diesel reference align with the values published by Mahbub *et al.* of 199 $g(CO_{2eq})\ km^{-1}$.[28] The diesel exhaust pipe emissions (Tank-to-Wheel) for the present LCA account for 177 $g(CO_{2eq})\ km^{-1}$. The 2020 European fleet target value aims at 95 $g(CO_{2eq})\ km^{-1}$ and takes manufacturer specifications as a calculation basis. For the present study the specific energy demand of the passenger car orientates on a current mid-class vehicle under real driving conditions (2.37 MJ km^{-1}; 6.6 L of diesel fuel).

With regard to H_2 production it should be recalled that in the case of PtX all of the final fuel energy content is provided by H_2 or rather the upstream electricity. Due to a chain of involved conversion efficiencies even minor shares of a carbon intensive electricity supplier (coal-fired or natural gas power plants) are mirrored in the PtX products' GWP footprint. The same accounts for the thermal heat supply for synthesis and distillation steps. The WtW results for the Direct-Air-Capture cases increase by 114 $g(CO_{2eq})\ km^{-1}$ in the case of a natural gas based provision of necessary low-temperature heat for CO_2 desorption.

The steps of methanol- and OME-synthesis account for 31–42% of the total OME_{3-5} life-cycle GHG emissions. Here the synthesis steps in the case of ammonia result in a slightly higher GHG emission since CO_2 containing purge streams are of fossil origin.

Case [OME2050 GR + RE]. The GHG footprint of the REMod based 2050 electricity grid mix results in 100 $g(CO_{2eq})\ kWh_{el}^{-1}$. Accompanied by a 40% share of local wind and PV electricity the applied electricity's total footprint results in 81 $g(CO_{2eq})\ kWh_{el}^{-1}$. With a less carbon-intensive electricity provision the GHG emissions per km of driving distance can be lowered significantly by up to −40% and fall below the ones of the diesel reference system. The scenarios' total specific GHG emissions of the OME_{3-5} product system result in 124–151 $g(CO_{2eq})\ km^{-1}$.

Case [OME2018 HY + RE]. The [OME2018 HY + RE] scenarios profit from a very low GWP for an electricity of 20 $g(CO_{2eq})\ kWh_{el}^{-1}$ (*i.e.* hydropower). However, when assessing life cycle impacts of hydropower it is important to consider that further environmental impact categories are heavily dependent on the type, capacity and location of the facility.[73,74] For this low-carbon electricity provision the GHG emissions for OME_{3-5} fuel clearly fall below the emissions of driving with conventional diesel fuel by −59% to −86%. The DAC supplied with thermal energy from natural gas is in the range of fossil diesel fuel.

GWP of the electrolytic H_2 production. When based on the 2018 grid + RE electricity mix the life cycle phase of H_2 production accounts for 53–68% of the PtL systems' total overall GWP. GHG emissions arising from PEM electrolysers sum up to 18.3 $kg(CO_{2eq})$ per $kg(H_2)$, which is significantly higher than that of conventional H_2 production such as steam-reforming of natural gas (9.0–13.0 $kg(CO_{2eq})$ per $kg(H_2)$)[75–77] or coal gasification (11.0–12.5 $kg(CO_{2eq})$ per $kg(H_2)$).[77] In the case of [OME2050

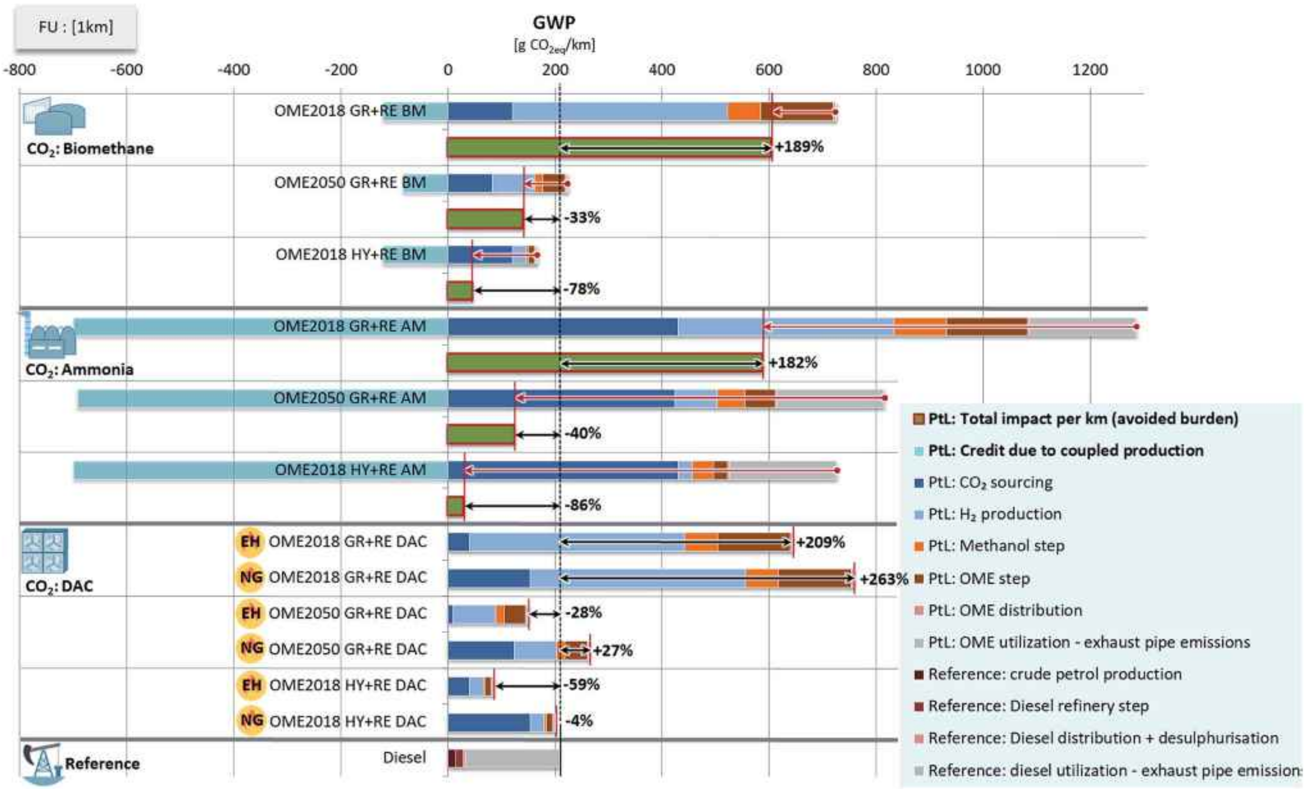

Fig. 3 Product specific well-to-wheel life cycle impact assessment results (GWP_{100a} [g CO_{2eq} km^{-1}]) for the assessed product systems. In the case of subtraction of an avoided burden the respective negative value is indicated in light blue. The resulting total impact is plotted as a green bar. The difference compared to the conventional diesel is specified with black arrows. For the CO_2 case Direct-Air-Capture, the thermal demand of the DAC plant is met either by exhaust heat (EH, burden-free) or natural gas (NG).

GR + RE] the life cycle phase of H_2 production results in a reduced GWP impact of 3.5 kg(CO_{2eq}) per kg(H_2). Other published GWP footprints for low-carbon H_2 production also clearly depend on the electricity source and vary between 0.6 kg(CO_{2eq}) per kg(H_2),[75,78] 1.9 kg(CO_{2eq}) per kg(H_2)[78] and 3.0 kg(CO_{2eq}) per kg(H_2).[79] Electrolysis hardware is, if part of the respective LCA, identified to have a minor impact. In the present assessment the share of GWP impact resulting from the PEM hardware varies between 0.6% (2018: 40 MW_{el} PEM, lifetime 50k h) and 1.8% (2018: 35 MW_{el} PEM, lifetime 125k h) of the H_2 production phase.

Thermal demand of synthesis and distillation. The synthesis and distillation steps are characterised by a high thermal energy demand (4.84 MWh_{th} per t(OME_{3-5}) produced). In case low-carbon-electricity is available these steps can benefit from thermal energy provided *via* electric energy. If natural gas is used for steam and heat production its proportional GWP sums up to 144 g(CO_{2eq}) km^{-1}. A switch to an electricity based thermal supply in the 2050 grid mix decreases the total GWP of the two synthesis steps by 72%. At the same time the electricity demand of the PtL foreground system (PEM electrolyser + synthesis and distillation) is increased from 1.27 kWh_{el} km^{-1} to 1.79 kWh_{el} km^{-1}. The temperature level of the necessary heat supply for methanol dehydrogenation to formaldehyde is at *ca.* 700 °C, equal to a thermal demand of 6.93 MW_{th}. Thus a thermal supply *via* excess heat at such high temperatures seems highly case-dependent. However, industrial processes requiring high temperature process heat (>500 °C) such as pig iron and steel mills, stone and brick production or the glass and ceramics industry are available and at the same time due to high direct CO_2 emissions, a potential CCU case.[80] If not utilised otherwise the available high temperature excess heat can thus be available as a "burden free" heat source to meet the thermal demand of the PtL process. For a hypothetical scenario in 2050 where the assessed OME_{3-5} production is supplied with high temperature excess heat the overall GWP can be lowered to 94 g(CO_{2eq}) km^{-1}, −55% in comparison to the reference diesel process' GWP. The impact related to the provision of PtL plant hardware and infrastructure lies between 0.8% [OME2018 GR + RE] and 17% [OME2018 HY + RE] of the overall WtW GHG emissions.

Further environmental impacts

Fig. 4 shows the further assessed environmental impact categories for the CO_2 case Biomethane. The results are normalised to the diesel reference. All results are again based on the avoided burden methodology.

For the [OME2018 GR + RE] scenarios synthetic fuel production and utilisation performs worse than the diesel reference for all impact categories. The largest contributor for most categories is the fossil share of the electricity used. With

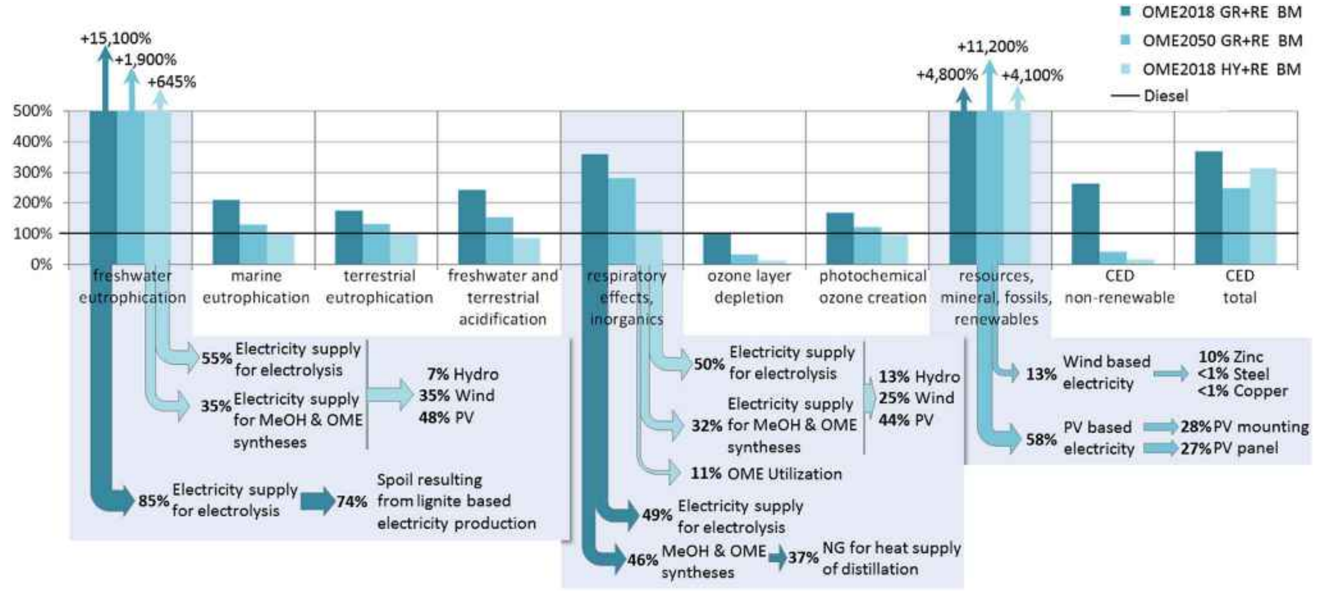

Fig. 4 Further evaluated impact categories by means of the CO_2 case [BM]. Relative shares relate to the diesel reference (100%). The flows presented exemplify the cause of specific impact categories. The percentage value for the specific initial causer relates to the absolute value of the impact category (*e.g.* spoil from lignite mining causes 74% of the overall freshwater eutrophication in the scenario [OME2018 GR + RE BM]).

a reduction of fossil energy shares for the [OME2050 GR + RE] and the [OME2018 HY + RE] scenarios the impacts can be reduced significantly for most cases. However, the categories addressing impacts on ecosystems remain high even with a low carbon electricity provision. The following subsections focus on the worse performing categories and analyze the respective cause in this context.

Freshwater eutrophication. The impact category freshwater eutrophication (kg P_{eq}) is outstanding by exceeding the diesel reference by 15 100% for the [OME2018 + RE] scenario. Here the largest share (74%) can be attributed to lignite based electricity provision, more precisely to the spoil and tailing wastes resulting from opencast mining.[81] However, even without any direct fossil-based electricity in the [OME2018 HY + RE] scenario, the contribution to freshwater eutrophication remains high (+645%). One main reason for eutrophication even for RE-based electricity is the provision of minerals and metals for the manufacturing of RE plants. Additionally the electricity for the upstream manufacturing processes of wind energy generators and solar modules is supplied by the manufacturing country's electricity mix and hence include fossil energies. Forthcoming LCA studies for future scenarios should therefore account for changes in the electricity supply of RE manufacturing processes. The assessed environmental footprints of RE technologies will otherwise appear high and not reflect any progress in future defossilisation.

Respiratory effects, inorganics. The category respiratory effects is represented by particulate matter (PM) formation (kg $PM2.5_{eq}$). In the case of the [OME2018 GR + RE] scenario PM formation is dominated by the combustion of fossil resources for the supply of electricity (49%) and syntheses' thermal energy (46%). For the low carbon scenario [OME2018 HY + RE] 82% of PM-formation can be attributed to the electricity supply. Up to 11% of the respiratory effects can be accounted to the OME utilisation phase although direct PM formation has been considered as non-existent in the case of 100% OME_{3-5} fuel. This is due to the formation of secondary PM equivalents such as NO_x which are part of this impact category.

Resource depletion. The depletion of resources (minerals, fossils, renewables, kg Sb_{eq}) clearly exceeds the fossil reference for all PtL scenarios. The major share is attributed to the demand for minerals and metals during the manufacturing of RE plants, more precisely to the need for molybdenum (alloy), zinc (galvanizing), copper (generators and cables), cobalt (magnets), and iron (steel constructions). These minerals and metals represent an integral part of RE technologies and thus increase even more for the RE dominated scenario [OME2050 GR + RE]. However, future RE plants will feature increased efficiencies and installed capacities. This in turn will lead to specifically lower amounts of incorporated minerals and metals per energy harvested.[82] Nonetheless, the very high increase up to 11 200% resource depletion represents a rising future environmental issue which has to be addressed by material efficiency including improved recycling ratios and as well less extensive mining processes.

Cumulative energy demand. The total cumulative energy demand (CED total; MJ_{eq}) for the production of OME_{3-5} is increased when compared to fossil-based production. This relates to the concept of the "free-lunch" for fossil-based energy carrier production. Fossil fuels and energy carriers source their energy content from high-carbon containing fossil resources. The amount of primary energy to be considered is the amount of heating value extracted from these fossil resources. For PtL products all of the final energy content is to be provided electrically and hence linked to multiple conversion steps and efficiencies. Hence, on the one hand, it is essential to decrease the total energy demand by further technology development/efficiency improvements whilst fulfilling the energy demand using a very high share of RE. This allows for a low share of fossil-based energy content, mirrored in the CED non-renewable. Here the [OME2050 GR + RE BM] and the [OME2018 HY + RE BM] scenarios are clearly less fossil-intensive than the fossil diesel reference. All statements made in terms of the qualitative results are transferable to the other two evaluated CO_2 sources.

Sensitivity of life cycle impact assessment results

Variations in supplied electricity and water electrolysis efficiency. The life cycle impact assessment results demonstrated that the process energies both electric as well as thermal energies significantly influence the overall GHG emission intensity. Similar to the case of previous power-to-hydrogen and -methanol studies our results show that the energy intensity of the electrolytic H_2 supply proves to be a main driver of the overall GHG intensity.[79,83–85] The specific energy demand for H_2 generation strongly impacts on the PtL plants' total energy demand, whilst GHG emission intensity of the electricity supply also heavily impacts on the synfuels' GHG emissions.

Therefore it is clear that high efficiency water splitting processes are even more necessary in the cases of a carbon-intensive electricity supply. Fig. 5 shows the dependency of the WtW GHG emissions [g(CO_{2eq}) km^{-1}] on the water electrolysis system efficiency and the GWP intensity of the input electricity [g(CO_{2eq}) kWh$_{el}^{-1}$]. The CO_2 case Biomethane serves as a basis for this sensitivity evaluation. Thermal energy is assumed to be supplied electrically. The sensitivity results reveal that, depending on the water electrolysis system efficiency, an electricity supply with a GWP > 95–115 g(CO_{2eq}) kWh$_{el}^{-1}$ will result in emissions exceeding the WtW emissions of driving with conventional diesel fuel. Input electricity with a GWP < 50 g(CO_{2eq}) kWh$_{el}^{-1}$ such as hydro, wind and solar offers WtW GHG emissions considerably below 100 g(CO_{2eq}) km^{-1}. In the case of a supply from national electricity grids only a few European countries (*i.e.* Sweden, Norway or Iceland) currently offer low GHG intensive grid electricity. Furthermore, the sensitivity analysis shows that for low GHG intensive electricity, water electrolysis efficiency plays a minor role in GWP impact reduction. From an economic perspective, a high water electrolysis efficiency remains, besides the utilisation rate, a key driver for low levelized cost of H_2.[55,86]

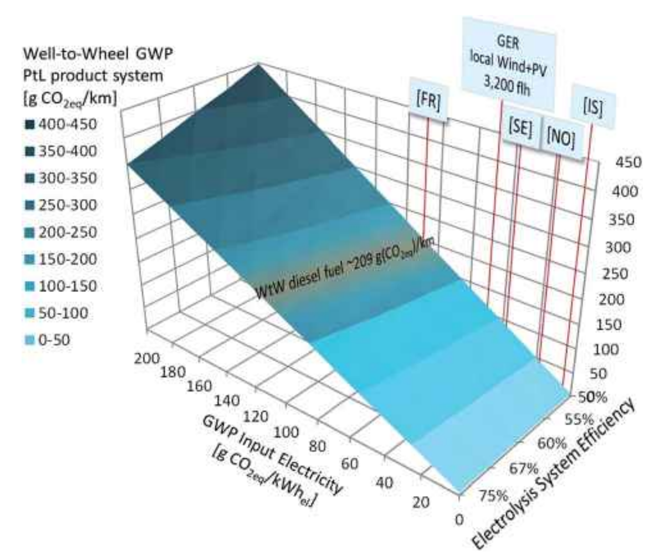

Fig. 5 Dependency of the PtL WtW GWP [g(CO_{2eq}) km^{-1}] on the GWP intensity of the input electricity [g(CO_{2eq}) kWh$_{el}^{-1}$] and the electrolysis system efficiency. Exemplary GWP intensities of national grid electricity mixes are indicated with red markers (FR: France, GER: Germany, SE: Sweden, NO: Norway, and IS: Iceland).

Further discussion regarding the dependency of the results based on an expanded system with or without crediting an avoided burden is provided in the ESI (S6).† It should be noted that the way of solving multifunctionality can influence life cycle impact results heavily as is the case for the present LCA: based on a preliminary study[17] two common allocation procedures have been applied to the multifunctional system: economical and cut-off allocation (CO_2 sourcing without impact). The effect can be high: economical and cut-off allocation show the potential to shift the above-mentioned results with a maximum increase of 300%.

Conclusions

The presented LCA of OME_{3-5} production based on a PtL approach and different scenarios (*e.g.* CO_2 source and electricity source) was performed on WtW emission basis using an avoided burden approach. Both 2018 and 2050 scenarios have been included to allow for technology developments and an increasing share of RE in the future grid electricity mix for Germany (Fig. 1). The results are very sensitive to the allocation procedure used in the LCA. Solving multifunctionality by an economical or cut-off allocation approach shows high sensitivity and can even reverse the results.

The GWP results (Fig. 3), representing the WtW GHG emissions, show that for a high share of RE the OME_{3-5} fuel is advantageous compared to fossil diesel. For the best assessed cases the WtW GHG emissions can be reduced by 86% to 59%, equating to 29–86 g(CO_{2eq}) km^{-1}. However, this significant reduction can only be assured with a very high RE electricity contribution. This is due to the fact that all of the synfuels' energy content has to be provided by electricity, chemically stored in the form of H_2. Hence, even low shares of fossil-based electricity, as will be the case for the current and near-future European grid mixes, will lead to a noticeable increase in related environmental impacts.

For conventional fossil fuels the bulk of WtW emissions (CO_2, CO, NO_x, PM, SO_2, and HC) arise during the utilisation phase. This results in high local exhaust pipe emissions. For fossil fuels the production phase is of comparatively minor environmental significance – *i.e.* nature has already done the work. Conversely for synthetic fuels such as OME_{3-5}, exhaust pipe emissions, in particular NO_x, PM and SO_2, can be reduced significantly due to their purity and combustion chemistry.[29,66] Thus, the cause of WtW emissions is rather shifted to the life cycle phase of synfuel production, more precisely the phase of electricity production.

Varying of CO_2 sources showed existing but small impacts on the total WtW GHG emissions depending on the required capturing effort. Hence, higher CO_2 concentrations and less contained impurities are beneficial. As a consequence this emphasises the utilisation of concentrated industrial waste gases.[87] However, to close the carbon cycle in the long-term the utilisation of atmospheric CO_2 either based on biomass or DAC is inevitable. DAC demands further technology development in terms of thermal energy demand but benefits from an integration of low-temperature excess heat.

Through the discussed sensitivity analysis, it was demonstrated that future defossilisation of grid electricity will lead to a significant reduction in synfuel GWP. In order to enable significantly reduced WtW GHG emissions of <100 g(CO_{2eq}) km^{-1} an electricity footprint of <50 g(CO_{2eq}) kWh_{el}^{-1} is identified for the assessed process configuration. Currently, only a few countries offer an electricity grid mix below this footprint. If powered by local RE it is important to emphasise that large-scale PtL plants of the future (*i.e.* going beyond pilot-phase) must be powered by dedicated installed RE capacities. A grid-connection should remain in any case enabling PtL plants to provide important energy balancing and limit expansion of the grid. The legal interpretation in Germany of electrolysis and PtL plants acting as "end consumers" is, in turn, inhibiting faster progress in this respect. However, in the case of a 100% supply from local RE the annual full load hours can be significantly reduced accompanied by a fluctuating H_2 production. This in turn necessitates intermediate H_2 storage for the decoupling of H_2 production and steady-state synthesis. Techno-economic studies assessing such PtL scenarios exhibit increased depreciation and production cost.[27,88] For these cases system optimization towards high full load hours, reasonable H_2 storage demand and levelized cost of H_2 are the main target. Such aspects are expected to be addressed by further, more expansive LCA studies. Future large-scale PtL plants (and PtX in general) are even more likely to be realised in countries with higher solar irradiance and wind occurrence resulting in (besides potentially low GWP) optimised levelized cost of electricity and increased full load hours (*e.g.* Australia or Chile).

In addition it should be emphasised that an environmentally beneficial PtL production depends not only on GWP but also on a multitude of other impact categories. The further assessed impact categories show that even for an electricity supply completely based on the present RE technologies their upstream manufacturing processes can still cause significant increases in acidification, eutrophication, particulate matter, photochemical ozone creation and resource depletion (Fig. 5). This holistic consideration thus sheds light on the necessity of an ongoing radical, complete "system" defossilisation, material efficient manufacturing of RE plants, increased recycling ratios and improved mining processes. Only this holistic approach can enable a PtL and synfuel production which ensures, besides CO_2 mitigation, environmental advances over the present fossil fuelled liquid energy carriers.

Finally, as addressed in the Introduction, our findings indicate that future private transport is more likely to be fuelled by batteries (short- to mid-range distances), fuel cells (mid- to long-range) or, as a near-term solution for bringing down local PM- and NO_x-emissions, by blends of synthetic fuels such as OME_n. Synthetic fuels based on PtL processes will in turn be indispensable for use in heavy-duty applications, in the rail and maritime sector and in aviation.

Conflicts of interest

There are no conflicts to declare.

Nomenclature

a	Year
AEL	Alkaline water electrolysis
AM	Scenario with CO_2 from ammonia plant
BM	Scenario with CO_2 from biomethane upgrading plant
CED	Cumulative energy demand
CH_4	Methane
CO_2	Carbon dioxide
CO_{2eq}	Carbon dioxide equivalents
DAC	Direct air capture of CO_2/scenario with CO_2 from DAC
FU	Functional unit
GHG	Greenhouse gas
LCA	Life cycle assessment
LCI	Life cycle inventory
LCIA	Life cycle impact assessment
MEA	Membrane electrode assembly
NH_3	Ammonia
NO_x	Nitrogen oxides
OME	Oxymethylene dimethyl ethers
PEM	Proton exchange membrane water electrolysis
PM	Particulate matter
PtL	Power-to-liquid
PtX	Power-to-X
RE	Renewable energy
REMod	Fh ISE renewable energy model
TtW	Tank-to-wheel
vol%	Volume percent
wt%	Weight percent
WtT	Well-to-tank
WtW	Well-to-wheel

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Energy efficiency and economic assessment of imported energy carriers based on renewable electricity†

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The production of energy carriers based on renewable electricity *via* the Power-to-X (PtX) approach holds the key for a holistic transformation of our global industries from fossil fuels towards renewable energy sources. To compete with cheap fossils, PtX products demand energy-efficient processes and low-cost renewable electricity. Therefore, the import of PtX products from countries with high renewable energy potentials to countries with high energy demand presents a promising pathway. However, the question which set of PtX products qualifies as suitable for long-distance transport has not yet been answered. In this context, this paper assesses the energy and cost efficiency of five PtX energy carriers (methane, methanol, ammonia, liquefied hydrogen and hydrogen bound in LOHC). Furthermore, we evaluate the influence of fluctuating renewables, availability of water and transport distance in a case study for large-scale PtX production in Morocco. Our results show that the evaluated PtX pathway efficiencies vary between 40–52% (base cases) and 44–58% (optimistic cases). None of the pathways assessed is significantly affected in its overall efficiency by a ship transport over an exemplary distance of 4000 km. However, for longer transport distances the cost difference between the assessed pathways increases. The production cost of the PtX energy carriers (124–156 € per MWh) depends on the availability of excess heat, energy density of the product and, if required, liquefaction efforts. In summary, the paper reveals that the long-distance transport and import of PtX products present an interesting option for the ongoing integration of renewable electricity into our energy system and industries. The petrochemical and steel industries in particular, as well as heavy goods transport, shipping and aviation, will be highly dependent on these imported synthetic energy sources.

Introduction

The global carbon cycle is out of balance due to drastically increased fossil greenhouse gas (GHG) emissions to the atmosphere and thus exceeding the capacity of our biogeochemical cycles.[1] The result is an anthropogenic greenhouse effect with its associated environmental problems[2] and extreme weather events – the latter having tripled since 1980.[3] In order to reach the goal of keeping the global temperature rise below 1.5 °C, a radical defossilisation of the global economies is necessary.[4,5] The good news is that even the scenarios with highest energy demands for 2050 are well surpassed by the latest estimations on the total renewable energy (RE) potential that could be harvested by utilisation of present technologies.[6] Characterised by an intense growth within the last two decades modern RE (*i.e.* excluding nuclear and traditional bioenergy) accounted for 10.6% of total final energy consumption in 2017 (+4.4% compared to 2016),[7] but only 2% is yet covered by *electricity* generated with modern renewable technologies. Up to 80% of the total final energy consumption is still covered by fossil fuels.

The integration of RE beyond direct electrification into the energy, mobility, industry and private sectors *via* hydrogen (H_2) based renewable energy carriers is referred to as "Power-to-X" (PtX). When powered with renewable electricity PtX can enable highly defossilised primary energy provision. It represents a cornerstone for integrated energy systems and thus, a closing of the carbon cycle.[8] However, shifting our sectors from fossil to RE based primary energy resources requires magnitudes of already installed RE capacities.[9,10] For example, replacing fossil based precursors in the chemical sector with PtX based chemicals would lead to a significant increase in the electricity demand. In this context, Kätelhön *et al.* 2019 substituted the fossil based precursors for the production of 20 large-volume

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chemicals (accounting for more than 75% of the GHG emitted in the chemical industry) with RE-based PtX pathways.[10] The result has been a demand for low-carbon electricity between 18.1 and 32.0 PWh_{el} per year – which surpasses the current global electricity demand (23.0 PWh_{el} per year in 2018).[11] For another sector, global transports, the total energy demand currently sums up to ~35 PWh per year.[12] Enormous efforts are underway to electrify it, either in a direct form *via* electric vehicles or indirectly *via* H_2 based power trains (fuel cells and internal combustion engines with synthetic fuels). Although, the electrification of global transport has a certain efficiency potential, it can be assumed that the global demand for renewable electricity will also increase significantly for this sector.

In countries with high energy demands, the production of sufficient renewable electricity is not always possible. Thus, energy carriers based on renewable electricity are required. For example, the European Union targets at a decrease of the future primary energy demand from 18.2 PWh_{el} in 2017 to 17.3 PWh_{el} in 2020 and 15.9 PWh_{el} in 2030.[13,14] However, the total technical renewable electricity potential in the European Union sums up to 9–14 PWh_{el} per year (depending on installation density and yield parameters).[15] It remains questionable if this potential will be fully tapped within the next decades under the light of a slow expansion of national power grids and storage technologies, hesitant political frameworks and a "not-in-my-backyard" mentality in case of renewable energy projects.[16–21]

The future need for an import of renewable energy carriers

In their "Clean Energy for All Europeans" package[22] the European Commission recognises H_2 and PtX processes as key technologies on the pathway towards a defossilised system but at the same time underlines that "(PtX) technologies become attractive in the context of abundant electricity generated from carbon-free sources […]". It is very likely that regions characterised by a restricted RE potential and a present net-import of fossil energy carriers will as well in the future be dependent on an import of low-carbon energy carriers (*e.g. via* PtX). Considering that the generation cost of PtX products highly depend on the price of the input electricity[15,23,24] it becomes clear that any large-scale PtX production becomes relevant in countries with high RE potential and full-load-hours. In the context of a global PtX market the World Energy Council describes three criterions for potential large-scale PtX producers: (1) low-cost RE power, (2) large available areas exhibiting high solar and/or wind potentials, (3) political stability and an energy political framework.[25] In this context Fasihi *et al.* 2018 analysed the full load hours and levelised cost of electricity generation from photovoltaic and wind power plants on a global scale.[26] Levelised cost of renewable electricity as low as 17–20 € per MWh_{el} are described for the top sites in the world. Considering a proximity to the coast (desalinised seawater, access to ports) LCo(E) in the range of 25–30 € per MWh_{el} seem realistic. The here identified regions such as Spain, Morocco, Chile or Australia are as well listed by the World Energy Council as potential *PtX exporters*.

However, for a future export of PtX products from these identified countries, the aspects of social compatibility and sufficient RE availability have to be taken into account.[27] Scenarios based on the stated global energy policies show that the global demand for fossil fuels will significantly increase within the next decades mainly driven by an increasing population (with a better standard of living).[28] Additionally, many of these identified PtX exporters and their energy production are still characterised by a high share of fossil energies, a privatised energy sector and partially depend on energy imports from other countries. Therefore, the existing RE potential and a build-up of a sustainable energy infrastructure beyond export should also be used for macroeconomic and green development in the PtX exporting countries themselves.

Scope of the study

On the basis of the aspects discussed above it can be stated that: (1) a transformation of the global economies from fossil to RE based requires large amounts of installed RE capacities, (2) H_2 based energy carriers will be an important part of this transformation and (3) a global trade of RE *via* H_2 and other gaseous and liquid PtX products from regions with high RE availability to economic centers with high energy demand emerges unavoidable. In addition, the development of a global RE trade should only take place in combination with the introduction of socially acceptable and sustainable energy production in the RE-exporting countries themselves. This paper builds on these considerations and questions:

- What is the energy efficiency of different PtX pathways for long-distance distribution of RE *via* H_2 based energy carriers?
- How does the energy efficiency of these PtX pathways relate to their respective economic efficiency for a specific case study?

Under the background of the defined research questions this paper assesses five PtX production pathways from the perspective of energy and cost efficiency. The included PtX products are potential options for future renewable energy storage and transport at large scales and are a frequent part in recent scientific and politic debates: H_2 distributed in liquid state (LH_2), H_2 distributed with liquid organic hydrogen carriers (LOHC) as transportation medium (LOHC–H_2), liquid methane (LCH_4), methanol (CH_3OH) and ammonia (NH_3). A detailed combined assessment of these energy carriers is currently missing in the scientific literature.

During its first part, the paper is intended to offer estimations on PtX efficiencies when operated on a base-load and without any intermediate storage demands. We do not aspire to provide a pure efficiency ranking of these PtX pathways but rather highlight potential hotspots for efficiency optimisation. The efficiency analysis differentiates between a base and an optimistic case. The base case applies conversion efficiencies, electricity and heat demands at present technology levels. In turn, the optimistic case considers published near-future (~2030) target values for some of the process steps. By this we aim at giving a perspective on how overall pathway efficiencies can change if central process steps undergo technological advances. The selection of process parameters is outlined in the section "parameter inventory".

The second part of this work assesses the detailed cost distributions of the PtX pathways for an exemplary case study (Morocco) considering large-scale production and downstream long-distance ship transport to North-western Europe. The case study includes more detailed systemic and site-dependent parameters such as local availability of RE, their fluctuation, availability of water and necessary storage demands.

Part I – energy efficiency analysis

Fig. 1 shows the basic scheme for the five assessed PtX pathways. For the basic efficiency analysis we assume renewable electricity (1) to be available without fluctuation (fluctuating RE rendering storage technologies necessary will be considered for the case study in the second part of the paper). Renewable electricity covers both electrical and thermal energy demand of all process steps. The water supply for the electrolysis step is realised *via* a seawater desalination plant (2). This enables technical availability of water for all arid regions with high RE availability next to the sea. Hydrogen is produced *via* polymer exchange membrane (PEM) electrolysis (3) and in case of LCH_4, CH_3OH and NH_3 conditioned to synthesis pressure and temperature and fed to the reactor for catalytic conversion (4). In case of LCH_4 and LH_2 the product is brought to liquid state by cryogenic liquefaction (5). For this study, direct air capture technology (DAC) ((6) pathways LCH_4 and CH_3OH) is assumed as carbon source. Carbon capturing from industrial and biomass point-sources represents another less energy intensive CO_2 option. However, the availability of large-scale industrial CO_2 sources depends on the PtX location and CO_2 transportation to the point of further conversion could be necessary. The energetic effort for CO_2 liquefaction and transport *via* ship from quite remote areas to the PtX plant is limited and technically feasible.[29] From an energy point of view, atmospheric CO_2 capturing can be seen as a conservative assumption for PtX scenarios but enables location-independent CO_2 sourcing. DAC necessitates besides electricity, a heat source. On the one hand, the use of fossil natural gas for heat supply is not in the scope of this paper which focuses on fully defossilised pathways. On the other hand, utilisation of the final product (synthetic CH_4 or CH_3OH) would mean an efficiency loss compared to utilising direct electricity. Instead, the necessary heat demand is assumed to be covered by available excess heat from the exothermal synthesis step and an electric heating module. Finally, the respective PtX product is transported by ship (7) to the importing country (8). The functional unit of our assessment is 1 MJ of renewable energy carrier arrived at the final location. The assumed long-distance transportation covers 4000 km, representative for marine transport from Northwest Africa to North-western European ports (*e.g.* Hamburg or Rotterdam). The distance will be varied in a sensitivity analysis to cover as well longer routes. The International Maritime Organisation's (IMO) objective to lower the GHG emissions by at least 50% by 2050 (compared to 2008) and eliminate other harmful emissions necessitates intense defossilisation of the shipping sector.[30] Therefore, we assume that the ships use their transported energy carrier as fuel. The use of fossil based heavy oil contradicts an envisioned defossilised system and is therefore not in our scope.

Parameter inventory for the analysed PtX pathways

This chapter provides more information on the five PtX pathways, explains respective parameters and energy demands. In general the scale of the components orientates on an annual H_2 production of 42 500 t. The specifications of the seawater desalination and deionisation as well as the H_2 production apply to all assessed PtX pathways and will be described at the beginning of this section. A summarising parameter table is part of the ESI (ESI-S1†).

Sea water desalination and deionisation. Water provision *via* desalination of marine sea water is assumed to be based on seawater reverse osmosis (SWRO). Voutchkov *et al.* 2018 analysed the actual state and technological trend regarding SWRO with a focus on energy use.[31] Depending on salinity and temperature of the seawater, the applied membrane and plant capacity the energy demand for SWRO can vary between 2.5–3.1 $kWh_{el}\ m^{-3}$. Considering that the actual SWRO energy demand accounts for 65–80% of a desalination plants' total energy demand a range of 3.1–4.8 $kWh_{el}\ m^{-3}$ is possible for state-of-the-art medium to large size desalination plants. The surface salinity of marine regions varies depending on temperature, freshwater inflow from coastal regions and ocean currents.

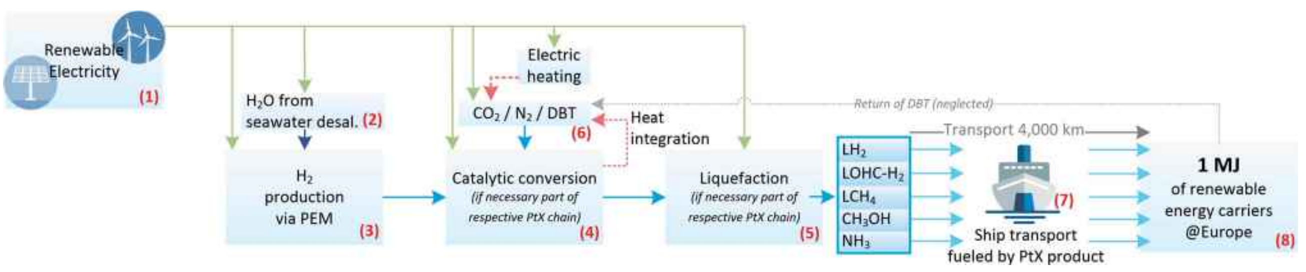

Fig. 1 System layout Part I – energy efficiency analysis: renewable electricity is the sole energy source for all process steps enabling a fully defossilised PtX product: H_2 distributed in liquid state (LH_2), H_2 distributed with liquid organic hydrogen carriers (LOHC) as transportation medium (LOHC–H_2), liquid methane (LCH_4), methanol (CH_3OH) and ammonia (NH_3). For the efficiency analysis (part I) fluctuations in renewable electricity production are neglected in order to be able to analyse the pure electricity-to-product efficiency. Part II of the paper will address the aspect of renewable electricity availability including the effects on storage requirements and economic efficiency.

Based on satellite measurements[32] a surface salinity of 35 000–37 000 mg L^{-1} can be seen as the higher range of salinity at global coastal regions in the subtropics (*e.g.* coast of Brazil, Argentina, parts of Australia) or the eastern Atlantic ocean (*e.g.* coast of Morocco).

For the hypothetical near-future small to medium scale plant of our study (~1200 m^3 per day), we assumed a conservative total energy demand of 3.75 kWh_{el} m^{-3}. Following the desalination it is assumed that the water will be deionised to fit the demands of the downstream water electrolysis. The process for deionisation is based on a process from the ecoinvent v3.3 database and considers an energy demand of 0.45 kWh_{el} m^{-3}.[33]

Hydrogen production *via* PEM water electrolysis. For the large-scale water electrolysis system (~200–300 MW_{el}), the emerging technology of proton exchange membrane (PEM) electrolysis has been considered. PEM systems offer specific advantages when placed in the context of fluctuating RE production and PtX-concepts: they enable a shorter start-up time (cold-start) and response time than other water electrolysis concepts (*e.g.* alkaline or high temperature sold-oxide electrolysis), low energy consumption in standby mode, elevated operational pressures (*e.g.* 30 bar) and higher current densities (potentially reducing stack size). The inputs of the assessed PEM system are water and electricity. The assumptions for the PEM systems' energy demand are based on a recent sector survey on manufacturer estimations for state-of-the-art and future electrolysis systems.[34] The base case assumes 4.81 kWh_{el} per $Nm^3(H_2)$ and considers the range in manufacturer estimations (4.40–5.20 kWh_{el} per $Nm^3(H_2)$) for existing to near-future PEM systems with capacities from 1–100 MW_{el}. The optimistic case calculates with 4.46 kWh_{el} per $Nm^3(H_2)$ and is based on the range in estimations (4.10–4.80 kWh_{el} per $Nm^3(H_2)$) for advanced PEM systems after 2030. The stoichiometric water demand of water electrolysis amounts to 8.94 $kg(H_2O)$ per $kg(H_2)$. Based on manufacturer specifications for a commercial PEM system we assume a water consumption of 10 $kg(H_2O)$ per $kg(H_2)$.[35]

$$H_2O(l) \rightarrow H_2(g) + 0.5O_2(g),\ \Delta H_R^0 = +285.8\ \mathrm{kJ}$$

PtX pathway for renewable liquid hydrogen – LH_2. The pathway liquid hydrogen (LH_2) comprises the smallest number of conversion steps and is therefore promising in terms of overall system efficiency.

Hydrogen liquefaction. Liquefaction of H_2 is based on a liquefaction plant design as described in the IDEALHY project.[36] LH_2 is provided at an absolute pressure of 2 bar, 23 K and a purity of 100%. Losses of hydrogen are assumed to be 1.6%, mainly caused at the feed gas compression step. Concerning the energy requirements of liquefaction, several investigations indicate that large-scale liquefiers will most probably be able to reach electricity consumption rates as low as 6.0 kWh_{el} per $kg(LH_2)$.[37] Today's hydrogen liquefiers with capacities up to 15 $t(H_2)$ per day show values of 10.0–12.0 kWh_{el} per $kg(LH_2)$.[38] Considering even larger conceptualised and as well existing liquefaction plants with capacities of several hundred tons per day, lower energy demands of 5.30–8.50 kWh_{el} per $kg(LH_2)$ are in a realistic range of technological feasibility. Accordingly, the H_2 liquefaction in our study differentiates between a base (8.0 kWh_{el} per $kg(LH_2)$) and an optimistic case (6.0 kWh_{el} per $kg(LH_2)$).

Transport of LH_2 via ship. The shipping of the liquefied H_2 to the final destination over a distance of 4000 km is assumed to be realised with a novel LH_2 carrier as conceptualised by Kamiya *et al.* 2015.[39] The proposed concept describes a large-scale carrier consisting of four vacuum panel type spherical tanks. The boil-off rate is described as 0.2% per day (or less). Since the study of Kamiya *et al.* 2015 does not include information on the ships propulsion energy demand we orientate on values based on propulsion datasheets for large conventional LNG carriers with a total capacity of 140 000 m^3 from MAN Diesel & Turbo.[40] The suitable engine results in a necessary SMCR power (specified maximum continuous rating) of 28 000 kW (at 20 knots/36 km per hour) for the selected ship size. Assuming that the propulsion system of the LH_2 carrier concept will be based on a H_2 gas motor with a rated efficiency of $\eta = 0.43$ the resulting specific LH_2 consumption sums up to 0.181 kWh per tkm ("per ton-kilometres") or 54 $kg(H_2)$ per km:

$$\dot{W}_{LH_2\ \mathrm{carrier}} = \frac{P_{SMCR}}{\mathrm{cap_{ship}} \times \rho_{LH_2} \times \nu_{ship} \times \eta_{H_2M}}$$

with

$\dot{W}_{LH_2\ \mathrm{carrier}}$ = energy demand of the LH_2 carrier in [kWh per tkm]

P_{SMCR} = specified maximum continuous rating of selected ship class (28 000 kW)

$\mathrm{cap_{ship}}$ = ship capacity (140 000 m^3)

ρ_{LH_2} = volumetric density of LH_2 (0.071 t per m^3)

ν_{ship} = ship speed (36 km per hour)

η_{H_2M} = efficiency of H_2 gas motor.

The boil-off rate of 0.2% per day results in a maximum evaporation of 28 $kg(LH_2)$ per km. This enables the use of the evaporating H_2 as fuel without any losses due to venting. Any losses during port times are neglected.

PtX pathway for renewable H_2 *via* LOHC – LOHC–H_2. The concept of LOHC comprises a reversible chemical reaction where a specific chemical molecule (the "LOHC") is loaded with gaseous H_2 which can be stored in liquid form showing elevated volumetric energy densities. Subsequent long-distance transportation of the hydrogenated LOHC is thus possible without any boil-off losses and is manageable in an easy way. To enable utilisation of the stored H_2 at the point of destination an endothermal dehydrogenation step has to be performed necessitating elevated temperatures at ambient pressure. A direct combustion of the loaded LOHCs is due to their high market prices and the fossil origin (*i.e.* release of fossil carbon) not in the scope of the concept. The most appropriate LOHC medium depends on a multitude of parameters such as the respective market price, the availability of waste heat at the place of dehydrogenation or the technological maturity of the conversion and release units.[41] Chemicals such as 1,2-dihydro-1,2-azaborine or *N*-ethylcarbazole either require additional solvents (reducing the storage capacity) and thus additional H_2

purification[42] or show lower conversion efficiencies during dehydrogenation.[43] Within our study, we focus on dibenzyltoluene (DBT), a chemical applicable as LOHC without further solvents and already applied for the LOHC concept at commercial but still comparably small scale (~4000 t(H_2) per year).[43,44]

Hydrogenation of LOHC. After its production *via* PEM electrolysis the pressurised H_2 is fed to the hydrogenation unit. The hydrogenation of DBT has to be performed at elevated pressures and temperatures. For this study, a pressure of 25 bar is applied fitting the pressure output level of the PEM electrolysis of 30 bar. Apart from start-up times, the exothermal hydrogenation reaction provides sufficient heat to realise a necessary temperature level of ~200–250 °C.[45] The LOHC loading density (wt% of H_2 in LOHC) is among other things relevant for the initial amount of LOHC medium to be purchased to realise a certain H_2 supply chain. For this study a LOHC loading density of 6.23 wt% H_2 is assumed.[45]

Transport of LOHC via ship. The handling of loaded LOHC (perhydro-DBT) is assumed to be comparable to the handling of conventional thermal oil and is assumed to be shipped in a tanker. Due to high purchase cost for DBT the assumed shipping size is smaller (73 000 t perhydro-DBT) than for the other assessed PtX pathways (compare section "Inventory of the economic parameters"). The tanker type and necessary engine size is selected based on propulsion datasheets for tankers from MAN Diesel & Turbo and results in an engine size of 12 300 kW (SMCR, at 28 km per hour) representing the "Aframax" class.[46] As for every PtX pathway in this study, it is assumed that the ship uses the transported PtX product as fuel. Therefore, propulsion power is assumed to be realised by means of a H_2 gas motor (η = 0.43; 30.8 kg(H_2) per km). The heat demand for necessary on-board dehydrogenation of perhydro-DBT (0.495 t(DBT) per km) is covered by the excess heat of the gas turbine.

Dehydrogenation of LOHC at the port of destination. An endothermal dehydrogenation (310 °C, 1 bar) step is required to release the stored H_2 from the perhydro-DBT. The necessary heat demand can either be supplied *via* oxidation of a share of released H_2 or, if available, *via* excess heat. For the efficiency analysis we consider a base (30 wt% of H_2 is burned) and an optimistic case (25 wt% of H_2 is burned)[47] and will as well discuss the effect if excess heat can be applied. A loss of DBT during dehydrogenation and the DBT return transport is not part of the efficiency analysis but will be considered within the case study.

PtX pathway for renewable liquid methane – LCH_4. The pathway for liquid methane production is based on CH_4 synthesis *via* Sabatier reaction with electrolytic H_2 and atmospheric CO_2 as educts commonly referred to as power-to-gas.[48] After downstream CH_4 liquefaction the LCH_4 can be handled comparable to liquefied natural gas (LNG) and is shipped *via* a large-scale LNG carrier. According to the number of necessary process steps the pathway for LCH_4 presents the longest conversion chain from all assessed PtX pathways.

CO_2 via direct air capture. CO_2 is obtained *via* direct air capture (DAC), a technology enabling site-independent availability of carbon – relevant for regions characterised by high RE availability but low availability of CO_2 containing industrial waste gases (*e.g.* North Africa, Argentina, Chile, parts of Australia). Additionally, DAC represents, besides CO_2 from biomass, the only CO_2 source for a possible closing of the carbon-cycle. However, due to low atmospheric CO_2 concentrations DAC technology is characterised by a high total energy demand compared to other higher concentrated CO_2 sources.[49,50] For this study, we assume the low-temperature solid sorbent based DAC technology as developed by the Suisse company Climeworks.[51] The capturing process is based on adsorbing CO_2 molecules onto special amine supported cellulose fibre filters. After full adsorption the filter is regenerated at elevated temperatures (100 °C) releasing a concentrated CO_2 stream (>99.9 vol%). Running multiple units in parallel enables a constant supply with atmospheric CO_2. Besides thermal heat (1.5–2.0 kWh_{th} per kg(CO_2)) electrical energy (0.2–0.3 kWh_{el} per kg(CO_2)) is required for operation of blowers and control units.[50,52] A base case (1.75 kWh_{th}; 0.25 kWh_{el}) represents the technological status for the capturing of 1 kg of CO_2.[53,54] An optimistic case (1.5 kWh_{th}; 0.2 kWh_{el}) represents a target value for mid-term energy demands.[50] Thermal energy is partially covered by means of heat integration from downstream methanation reaction. The remaining thermal energy demand is covered by an electric heater (η = 0.95). A burning of the CH_4 product is not reasonable from an efficiency point of view.

Methanation. Sabatier reaction for methanation of pure CO_2 represents a combination of the reversed water gas shift reaction (endothermal) and methanation of carbon monoxide (exothermal). The highly exothermal reaction is currently under research and takes place under moderate pressures of 6–8 bar and 280 °C.[55] The process concept as assessed by Müller *et al.* 2002 serves as basis for conversion parameters and energy demands.[56] The methanation reactor is operated at 8 bar and 280 °C. The Sabatier reaction provides excess heat (−3.0 kWh_{th} per kg(CH_4)) which is assumed to partially cover the thermal energy demand of the DAC modules. This in turn significantly reduces the heat demand of the DAC modules by 58–68%. For the compression of the CO_2 from ambient to synthesis pressure, an electricity demand of 0.14 kWh_{el} per kg(CH_4) is considered. The H_2 as obtained from the pressurised PEM electrolysis is already on reactor pressure.

$$CO_2(g) + 4H_2(g) \rightarrow CH_4(g) + 2H_2O(g), \Delta H^0_R = -167.9 \text{ kJ}$$

Liquefaction of CH_4. Depending on its composition liquefied natural gas (LNG) demands 540–590 times less storage volume than gaseous natural gas and is therefore already used as energy carrier for long distances. For distances >2000 km (offshore) or >4000 km (onshore) transport of LNG *via* ship is more economical than distribution *via* pipelines in gaseous state.[57] LNG trade has increased fivefold to 250 Mt per year compared to 1990.[58] In case of CH_4 which represents the largest share of LNG (87–99%, depending on origin),[59] a liquefaction step is therefore obvious. Pospíšil *et al.* 2019 assessed the energy demand of NG liquefaction processes based on literature and own simulations. Besides the process type, the specific liquefaction electricity demand is influenced by the size of the liquefaction plant and ranges from <0.25 to 0.75 kWh_{el} per kg(NG). Conducting an energy optimisation by means of improved flow rates for the mixed refrigerants within a liquefaction process Ali *et al.* 2018 reduced the theoretical electricity demand from 0.46 kWh_{el} per kg(NG) to 0.27 kWh_{el} per kg(NG).[60] Based on these considerations we assume for liquefaction of pure CH_4 an electricity demand of 0.5 $kWh_{el}\ kg^{-1}$ for the base case and 0.25 $kWh_{el}\ kg^{-1}$ for the optimistic case.

Transport of LCH_4 via ship. A conventional LNG carrier with a capacity of 140 000 m^3 is considered for transport of the liquefied CH_4. The carrier class and the necessary engine size are selected based on propulsion datasheets for LNG carriers from MAN Diesel & Turbo and results in an engine size of 28 000 kW (SMCR, at 36 km per hour) representing the "small conventional" class.[61] In our study, to avoid the use of fossil based fuel, this propulsion power shall be delivered by burning of the transported LCH_4. Therefore, we assume a dual fuel engine possible to be operated with natural gas at a rated efficiency of $\eta = 0.5$.[62] The resulting fuel consumption sums up to 0.026 kWh per tkm or 112 kg(CH_4) per km. The boil-off during ship transport should be prevented due to the high global warming potential of CH_4. To minimise the slip on LNG carriers reliquefaction systems are installed.[63] Modern LNG carriers feature boil-off rates between 0.10–0.15% per day.[64] For this study, an improved tank insulation system with a boil-off rate of 0.10% per day as recently proposed by the Kawasaki Shipbuilding Corporation is assumed.[65] The boil-off results in an evaporation of 68 kg(LH_2) per km enabling use of evaporating CH_4 as fuel without any losses.

PtX pathway for renewable methanol – CH_3OH. The CO_2 based methanol production for seasonal storage of RE and the implicit reuse of CO_2 has been frequently discussed in literature and has already been realised in pilot plants like the George Olah Renewable methanol plant.[23,66,67]

CO_2 via direct air capture. As for synthetic CH_4 production, the methanol pathway necessitates a carbon source which is assumed to be based on DAC as well. Compared to the LCH_4 pathway the methanol step is less exothermal and covers only a minor share of the DAC's thermal demand *via* excess heat. The remaining thermal demand is assumed to be covered by electric heating.

Methanol step. The process concept for the methanol reaction and distillation step is based on publication of Bongartz *et al.* 2019.[68] A new kinetic model (for commercial $Cu/ZnO_2/Al_2O_3$ catalysts) developed at Fraunhofer ISE and implemented in an Aspen simulation (see ESI-S2†) leads to conversion parameters and energy demands. The reactor system is operated at a pressure of 70 bar and a temperature of 250 °C. Heat integration *via* pinch-analysis enables pre-heating of the educt streams CO_2 and H_2. The remaining excess heat (0.09 kWh_{th} per kg(CH_3OH)) released below the internal heat utilisation range (<65 °C) is assumed to be available for the DAC modules' thermal energy demand. This in turn only slightly reduces the heat demand of the DAC modules by ~4%. The compression energy demand (0.31 kWh_{el} per kg(CH_3OH)) considers single-stage H_2, four-stage CO_2 and the recycle compressors. A process flow diagram for the CH_3OH step is included in the ESI.†

$$CO_2(g) + 3H_2(g) \rightarrow CH_3OH(l) + H_2O(l),\ \Delta H^0_R = -49.2\ kJ$$

Transport of CH_3OH via ship. In contrast to the LCH_4 pathway, the methanol pathway does not necessitate a separate liquefaction step to enable ship transport of a liquefied product. The ship transport orientates on a conventional tanker with a cargo capacity of 140 000 m^3. Tanker class and the resultant engine size are again based on propulsion datasheets for tankers from MAN Diesel & Turbo resulting in a necessary engine size of 15 200 kW (SMCR, at 28 km per hour, "Suezmax" class).[46] The first marine engines running on methanol are already in operation. A growing number of tests demonstrate feasibility of retrofitting existing diesel two-stroke engines for use with methanol.[69,70] Besides reduced NOx emissions, engine efficiency is reported as equal or even increased (+1–2%) when running on methanol. Therefore, efficiency of a conventional marine diesel engine is as well assumed for the methanol engine ($\eta = 0.5$). The resulting fuel consumption sums up to 0.010 kWh per tkm or 198 kg(CH_3OH) per km.

PtX pathway for renewable ammonia – NH_3. Ammonia is the most important feedstock for global fertiliser production. The conventional fossil based NH_3 production is largely based (77%) on syngas obtained from catalytic steam reforming of natural gas.[71] With an annual production of ~150 Mt NH_3 (2017), the annual global NH_3 economy is expected to grow significantly to an annual demand of 230 Mt(NH_3) by the end of 2025.[72,73] Additionally, NH_3 is considered as one promising carrier for renewably produced H_2 since it is easier to store and transport than gaseous H_2 and offers a higher energy density.[71,74] Moreover, liquefaction effort is lower than in case of LH_2 or LCH_4. However, as for CH_4 and CH_3OH a carrier for the H_2 molecule has to be provided.

N_2 via cryogenic air separation. Nitrogen (N_2) can be provided *via* cryogenic air separation units (ASU). Cryogenic distillation, a technology well proven and established at large scale, presents the major technology for N_2 supply in case of high volume and purity requirements.[75] Electricity requirement of the ASU is based on Althaus *et al.* 2007 (ref. 76) and the corresponding ecoinvent process.[77] The total electricity demand of an ASU largely depends on plant size and the grade of refrigeration recovery and varies between 0.5–0.8 kWh_{el} per kg(N_2). This spread is considered for the base and the optimistic case, respectively.

Ammonia production step. The Haber–Bosch process presents the most common method for the production of NH_3.[78] The iron-based catalyst facilitates an exothermic reaction of N_2 and H_2 at temperatures between 400–600 °C and pressure levels around 200–400 bar. Conversion parameters and energy requirements are based on own Aspen simulation (see ESI-S2†). Corresponding feed demands per kg of NH_3 sum up to 0.18 kg(H_2) and 0.84 kg(N_2) respectively. N_2 obtained from the ASU at −196 °C is vaporised and subsequently compressed to 250 bar like H_2. The exothermic ammonia formation yields the necessary energy to preheat the reactor feed stream. The electricity demand for feed compression and the recycle loop results in 0.48 kWh_{el} per kg(NH_3). The consumption of electrical energy can mainly be attributed to the compression of the two feed gas streams. The NH_3 product stream is liquefied (−33 °C) *via* cooling from evaporation of the N_2 feed obtained from the ASU.

$$N_2(g) + 3H_2(g) \rightarrow 2NH_3(g),\ \Delta H^0_R = -91.8\ \text{kJ}$$

Transport of NH_3 via ship. Long-distance shipping of NH_3 *via* ocean-going vessels is realised at low but non-cryogenic temperature (−33 °C) enabling transport in liquid state. The carrier class and the resultant engine size are aligned to conventional LNG carriers with a cargo capacity of 140 000 m^3. Similar to the LCH_4 PtX pathway, the engine size representing the "small conventional" class results in a necessary SMCR propulsion power demand of 28 000 kW (at 36 km per hour). Due to its high energy density (5.18 kWh_{LHV} per kg(LNH_3)) and efficient production process renewable NH_3 as shipping fuel is assessed in a number of research and pilot projects aiming at demonstrational container cargo vessels.[79–81] MAN Energy Solutions announced operation of its first naval NH_3 engine by 2022.[82] In a recent study, the Environmental Defense Fund Europe identified green NH_3 as one of the most promising alternatives for future electricity based fuels.[83] Advantages discussed by the authors are practicability in existing combustion engines or future fuel cells, the comparably high energy density when stored as liquid, the utilisation of existing logistics infrastructure and a safety and environmental risk profile manageable by existing standards. We assume NH_3 to be utilised in a combustion engine ($\eta = 0.5$) due to the potentially higher technology readiness level (TRL) than in case of promising full cell technology.[84] The fuel consumption of 0.016 kWh per tkm exceeds the boil-off rate of 0.04% per day (0.002 kWh per tkm), which is therefore included in the fuel demand.

Energy flow chart and energy efficiency for the analysed PtX pathways

Fig. 2 shows the energy flow charts and the overall efficiencies for the assessed PtX pathways including transportation *via* ship over 4000 km. The overall PtX efficiencies vary between 40.2–52.4% for the base and 44.1–57.9% for the optimistic cases. For all pathways, the electrolytic H_2 production is the main energy-intensive process step heavily affecting overall efficiencies. Hence, any technical improvement increasing electrolysis efficiency (*e.g.* reduction of internal losses, reduced current densities) or the H_2 conversion to final products will clearly increase the overall pathway efficiencies.

The provision of carbon and nitrogen (CH_3OH, LCH_4, NH_3) also requires energy. The NH_3 production pathway clearly benefits from a less energy intensive provision of the hydrogen carrier N_2 (0.08–0.13 MJ_{el} per MJ of product). Cryogenic air separation presents an industrially mature process at high TRL. At the same time, the low energy demanding availability of atmospheric N_2 poses a chance for future large-scale PtX projects to be more location-independent and focus on the availability of low-cost RE. In turn, the provision with atmospheric carbon for the LCH_4 and CH_3OH pathways *via* DAC emerges as energy intensive process step (LCH_4: 0.15–0.21 MJ_{el} per MJ of product; CH_3OH: 0.52–0.44 MJ_{el} per MJ of product). One reason is the low concentration of carbon in the ambient air. The provision of thermal energy *via* electric heating adds up to the electricity demand for the fans of the DAC units. For the case LCH_4, the thermal demand of the DAC units can be significantly reduced due to the integration of excess heat from the methanation step. The availability of unused heat sources poses an important efficiency enhancement in case CO_2 has to be provided *via* DAC. With the exception of one, all companies currently involved in the development of DAC technologies are focused on regeneration temperatures ≤ 100 °C.[50] This can enable the integration of excess heat even from processes with moderate temperature levels (*e.g.* food/beverage or textile industry).[85] For this study, DAC technology has been assumed to enable location-independent sourcing of carbon. Assuming, for example, high-concentrated industrial CO_2 point-sources such as the conventional, fossil based NH_3 or ethylene oxide production enables capturing of CO_2 with significantly reduced energy efforts of ~0.4 MJ_{el} per kg(CO_2).[49,86] Sourcing carbon from these kind of sources can lead to a significant efficiency increase in case of the LCH_4 (47.9–52.0%) and the CH_3OH (50.2–54.0%) pathway. In this case, the efficiencies are comparable to the NH_3 pathway.

The three synthesis steps are within a comparable range of efficiencies. Their performances depend besides the electricity demand for feed and recycle compression steps on their respective H_2 conversion efficiencies. Although the methanol synthesis inherently leads to a liquid synthesis product, it requires more energy for CO_2 sourcing and the compression of feed gases than the methane reaction *via* Sabatier. The Sabatier reactor operated at a moderate pressure shows a clear advantage over CH_3OH and NH_3 syntheses which need higher pressures. With regard to the CO_2 based methanol synthesis some other published process concepts show an improved H_2 conversion efficiency. However, for these cases the volume of the recycle stream and thus the recycle compressors' energy demand increased significantly.[87] We identified that a limitation of the recycle stream and the resulting reduced compression demand is beneficial for overall CH_3OH synthesis efficiency despite the slight increase in H_2 demand. A H_2 recovery concept (*e.g. via* pressure swing adsorption) for H_2 recirculation could further enhance synthesis efficiency.

The energy efficiency of the cryogenic liquefaction steps for the LH_2 and LCH_4 pathways clearly depends on the PtX plant scale and the possibilities for a thermal integration into the overall process chain. Within the range of the assumed process parameters the LH_2 pathway shows a higher specific energy demand (0.18–0.24 MJ_{el} per MJ(LH_2)) for the cryogenic liquefaction than the LCH_4 pathway (0.02–0.04 MJ_{el} per MJ(LCH_4)). The latter, in turn, necessitates a carbon source.

Long-distance shipping (4000 km) does not present a notable energy loss for the PtX pathways assessed and mostly depends on the energy-density of the product carried. Uncertainty

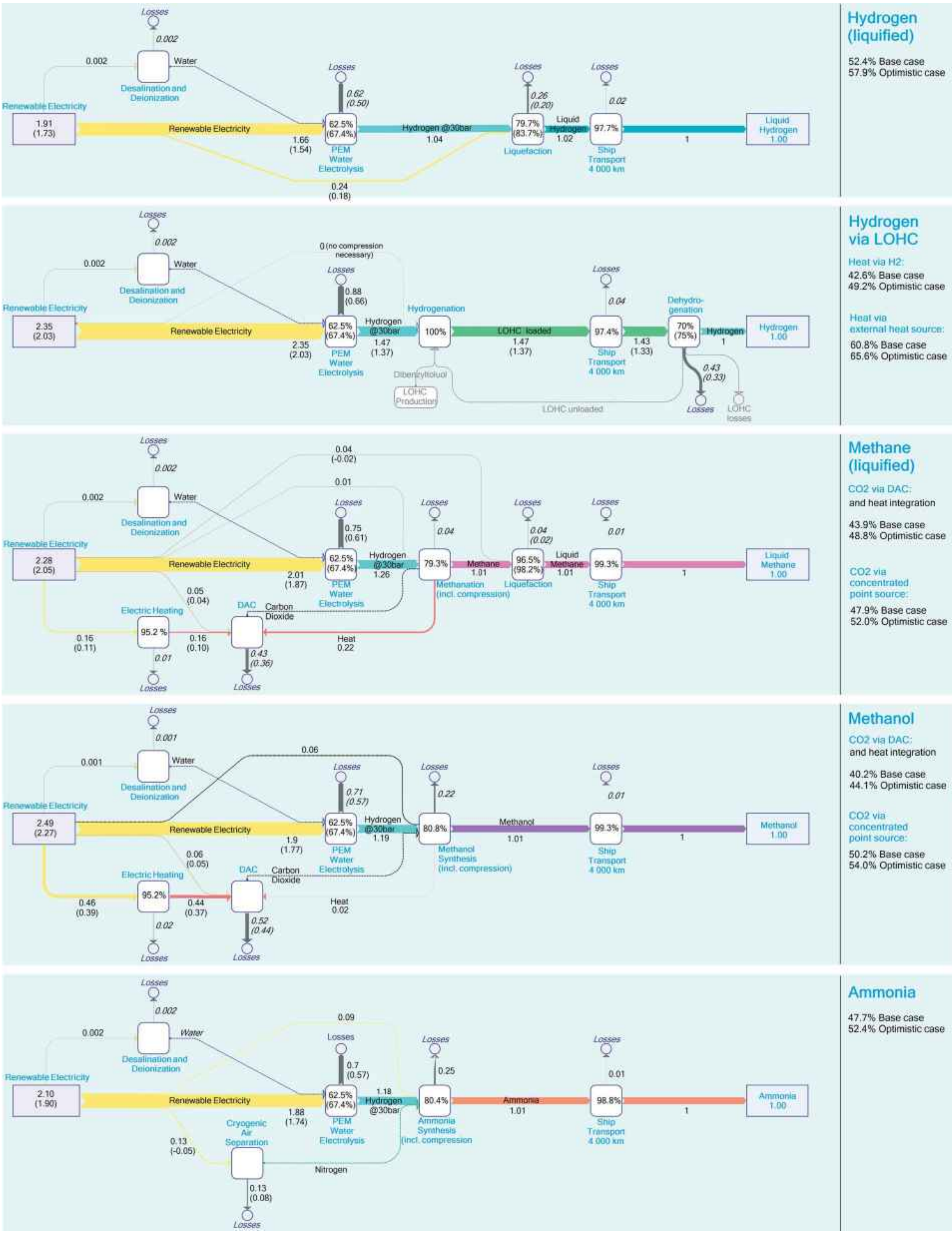

Fig. 2 Energy flows (in MJ) for the assessed PtX pathways based on a functional unit of 1 MJ (LHV) of renewable energy carrier. Values for the optimistic case are indicated in brackets for the respective process step.

remains with regard to the efficiency of the assumed H_2 and NH_3 engines which are so far not realised for dynamic applications and at this scale. Utilising fuel cells presents another option for on-board utilisation of the LH_2 which potentially can offer even elevated efficiencies > $50\%_{LHV}$. The considered LOHC, perhydro-DBT, with an H_2-content of 6.23 wt% has the lowest volumetric energy density of all assessed PtX shipping cargos and thus demands the most propulsion energy per unit of transported energy ($E_{ship,LOHC-H_2}$: 6.8 × 10^{-6} kWh per kWh and km); +278% compared to CH_3OH. Note that for the case LOHC–H_2 a smaller ship has been assumed than for the other PtX products due to economic reasons. Considering a comparable vessel (140 000 m^3) and ignoring high DBT purchase cost leads to a clear decrease of $E_{ship,LOHC-H_2}$ to 4.4 × 10^{-6} kWh per kWh and km. This results in a clear decrease, falling below the specific energy demand for the LH_2 carrier. The shipping processes of both, CH_3OH and cryogenic LCH_4, benefit from high volumetric energy densities and thus show the lowest propulsion energy demand per unit of transported energy (1.8 × 10^{-6} and 1.9 × 10^{-6} kWh per kWh and km respectively).

In summary, the pathway for LH_2 shows the highest overall efficiency (52.4–57.9%). The NH_3 pathway (47.7–52.4%) benefits from an energy-efficient provision of N_2, the absence of energy-intensive liquefaction and a PtX product with comparably high energy-density. The pathways for LOHC–H_2 (42.6–49.2%), LCH_4 (43.9–48.8%) and CH_3OH (40.2–44.1%) remain within a comparable range of efficiencies. Deviations here can occur for the amount of integrable excess heat (LCH_4, CH_3OH) and the necessary thermal demand for the dehydrogenation of the LOHC–H_2.

The final utilisation of the energy carriers is not included in the efficiency analysis due to the versatile field of potential applications. Hydrogen can be used with very high efficiencies (*e.g.* in fuel cell cars or fuel cells for stationary applications) where, in turn, CH_4 and CH_3OH will offer lower efficiencies at least in mobile applications. For the direct utilisation of NH_3, further investigation on direct utilisation is required. In case of cracking of NH_3 as H_2 supplier the losses could be limited by optimised catalysts enabling cracking at reduced temperatures (see "conclusions").

The presented efficiency analysis serves for the identification of energy loss hot-spots and potential levers for the energy optimisation of PtX pathways. The final criteria by which the suitability and realisation potential of PtX-processes is determined rather depends on their techno-economic competitiveness. Additionally, the environmental efficiency assessed by a holistic life-cycle-assessment should be included for any decision-making. The subsequent section presents a case study for the assessed PtX routes including long-distance shipping to provide an estimate of their economic efficiency.

Part II – case study for the economic assessment of the proposed PtX pathways

For a holistic assessment of PtX pathways, the total cost of the respective PtX product must also be included in the considerations. The following case study, located in the region Morocco/Western Sahara, adds economic conclusions to the preceding discussion on PtX pathway efficiencies. By this the influence of site and weather conditions on plant scales, storage demands, full load hours and finally the cost of production can be taken into account. It should be noted that the Western Sahara is on the one hand a top region for harvesting RE but on the other remains a region whose international legal status is still not finally determined.[88,89] For a future implementation of large RE and PtX capacities it is therefore important to involve local stakeholders and to respect socio-economic boundary conditions.[90]

Economics of imported synthetic fuels – existing studies

Fasihi *et al.* 2016 assessed the production and shipping cost of synthetic fuels (jet fuel and FT-diesel *via* Power-to-Liquid (PtL)) from large-scale Fischer–Tropsch (FT) synthesis fed with CO_2 captured from the atmosphere and renewable H_2 from an alkaline electrolyser.[91] The overall process efficiency (excluding the FT side product naphtha) resulted in 49.4%. The production cost for the FT-diesel was between 64–75 € per $MWh_{FT\text{-}Diesel,LHV}$ equalling 0.59–0.69 € per liter, values comparably low for studies on PtL economics. This can be explained in part by the high full load hours for the assumed hybrid PV-wind power plant (6840 hours per year) resulting in low cost for the PtL systems' input electricity of 23 € per MWh_{el}. Additionally, assumptions regarding low investment cost of 319 € per kW_{el} and high electrolysis efficiency ($73.1\%_{LHV}$) lead to low FT-diesel production cost. For another study, Fasihi *et al.* 2015 analysed the production of synthetic CH_4 in Patagonia and shipping of the liquefied product to Japan.[92] The parameters used for the economic assessment are comparable to their study on PtL. The final product cost including the shipping over 17 500 km summed up to 62–73 € per $MWh_{CH_4,LHV}$. Fasihi's assessments already show the importance of high RE full load hours which indicate the price of the renewable input electricity and PtX production cost. This, in turn, leads to the presumption that a large-scale PtL production site should rather be selected based on high RE potentials than based on a close proximity to the end consumer.

In another study, Heuser *et al.* 2019 avoid any downstream catalytic conversion of produced electrolytic H_2.[93] Their proposed system is designed to cover a prospected future Japanese annual hydrogen demand of 8.8 Mt(H_2) *via* marine LH_2 transport from Patagonia. Their GW-scale PtG system (115 GW_{el}) for the cost assessment includes electrolytic H_2 production (115 GW_{el}) based on wind electricity, gaseous H_2-pipeline transport, cryogenic H_2 storage and liquefaction and finally LH_2 transport *via* LH_2 carrier to Japan. The LH_2 product cost excluding long-distance transport sum up to 99 € per $MWh_{LH_2,LHV}$. The assumed shipping to Japan increases the product cost to 133 € per $MWh_{LH_2,LHV}$. As the authors conclude, at this price level and used in efficient fuel cells, H_2 can be considered competitive with combustion engines running on conventional gasoline.

Niermann *et al.* 2019 analysed various LOHCs for long-distance ship transport of renewable energy.[41] Among the substances analysed DBT and methanol (including methanol cracking to H_2 at the point of utilisation) performed best from an economic perspective. The authors concluded that the provision of necessary heat for dehydrogenation/cracking is one of the largest cost factors and that the transport by ships is significantly cheaper than H_2 transport *via* pipeline within the assessed distance of 5000 km.

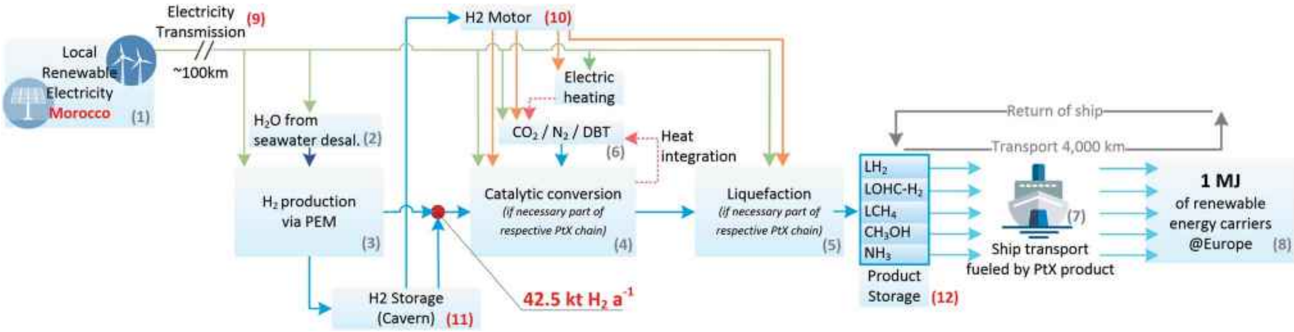

Fig. 3 System layout part II – case study: components (9–12) have been added to enable an operation with 100% fluctuating local renewables and a steady-state provision with 42 500 t(H_2) per year.

Scope and methodology of the case study

The general system layout is depicted in Fig. 3. Scale and layout of the assessed PtX systems orientate on a near future (~2030) medium- to large-scale PtX product system 100% based on local renewable electricity generation. Hence, applied conversion parameters and efficiencies are based on the optimistic values which have as well been used for the preceding efficiency analysis. The dynamic electricity and H_2 production is coupled downstream with steady-state synthesis and liquefaction steps converting 42 500 t(H_2) per year into valuable PtX products. During periods of insufficient renewable electricity production, the steady state processes are supplied with electricity generated in an H_2 motor (10) which in turn is operated with H_2 stored in a cavern (11). The existence of suitable salt deposits for the installation of cost-efficient H_2 caverns (<10 € per kg(H_2)) is a necessary prerequisite for this case study. South-western Morocco is characterised by the existence of large Mesozoic and Permian salt deposits which are potential geological structures for the installation of H_2 cavern storages.[94] The use of very large underground pipe storages (250–400 € per kg(H_2)) is not in the scope of the assessment since preceding PtX studies already showed their economic inefficiency.[23,95] The PtX plant is assumed close to the sea to allow for the use of seawater desalination. Therefore, a transmission (~100 km) of the renewable electricity (9) from the chosen region of the RE plants (26°15′03.6″N, 13°45′39.6″W) to the location of the PtX plant has been assumed. In order to decouple PtX production and shipping processes, product storage tanks are provided (12).

Weather data (solar irradiation and wind speeds) for the respective RE location (Fig. 4, top) using a ten-year dataset (2007–2016, typical meteorological years TMY) served as basis for the PtX process simulations.[96] The RE location has been chosen based on criteria considering a distance to the sea not larger than 150 km and an optimised combination of annual average wind speeds[97] and solar irradiation.[98] The weather data has been used for simulation of fluctuating electricity generation using the RE-simulation software "System Advisor Model" (SAM).[99] Siemens Gamesa G128 (4.5 $MW_{p,el}$) wind turbines and ground-mounted PV panels (multiple 4 $kW_{p,el}$, 1-axis tracking) have been selected as basis for the RE power curves (compare ESI-S3†). The fluctuating RE generation data has then been applied in the self-developed MATLAB® Simulink toolbox *H2ProSim* for simulation and optimisation of each assessed PtX process. The *H2ProSim* results have than been used for the calculation of the respective production cost (levelised cost of PtX product, LCo(X)):

$$\mathrm{LCo(X)} = \frac{\mathrm{ANF} \times \mathrm{CAPEX}_x + \mathrm{OPEX}_x}{\mathrm{PC}_x}$$

with

CAPEX_x = total investment cost of the respective PtX pathway

OPEX_x = annual operational cost of the respective PtX pathway

PC_x = production capacity of the respective PtX pathway.

ANF = annuity factor:

$$\mathrm{ANF} = \frac{(1+i)^n \times i}{(1+i)^n - 1}$$

i = assumed rate of interest: 5% per a

n = plant lifetime: 20 years.

The lifetime of the PtX components is assumed with 20 years. The replacement of electrolysis stacks becomes necessary after 10 years. If given for different scales, cost data from literature have been adjusted to the scale of the respective PtX components *via* the rule of the rule of six-tenths:

$$I_\mathrm{B} = I_\mathrm{A} \times \left(\frac{C_\mathrm{B}}{C_\mathrm{A}}\right)^x$$

with

I_B = investment cost for the component at capacity B

I_A = known investment cost for the component at capacity A

$C_\mathrm{B}/C_\mathrm{A}$ = capacity ratio of the two components

x = size exponent; 0.6 as "hands-on" value for process equipment.

Inventory of the economic parameters

This section discusses the installed capacities for each of the PtX pathways (Table 1). They serve as initial information for the economic assessment. The ESI (ESI-S4†) contains detailed information on the chosen cost parameters, corresponding literature and as well a description for the calculation of the shipping processes.

Prices for the generated wind and PV electricity have been chosen based on a comparison of the site dependent full load

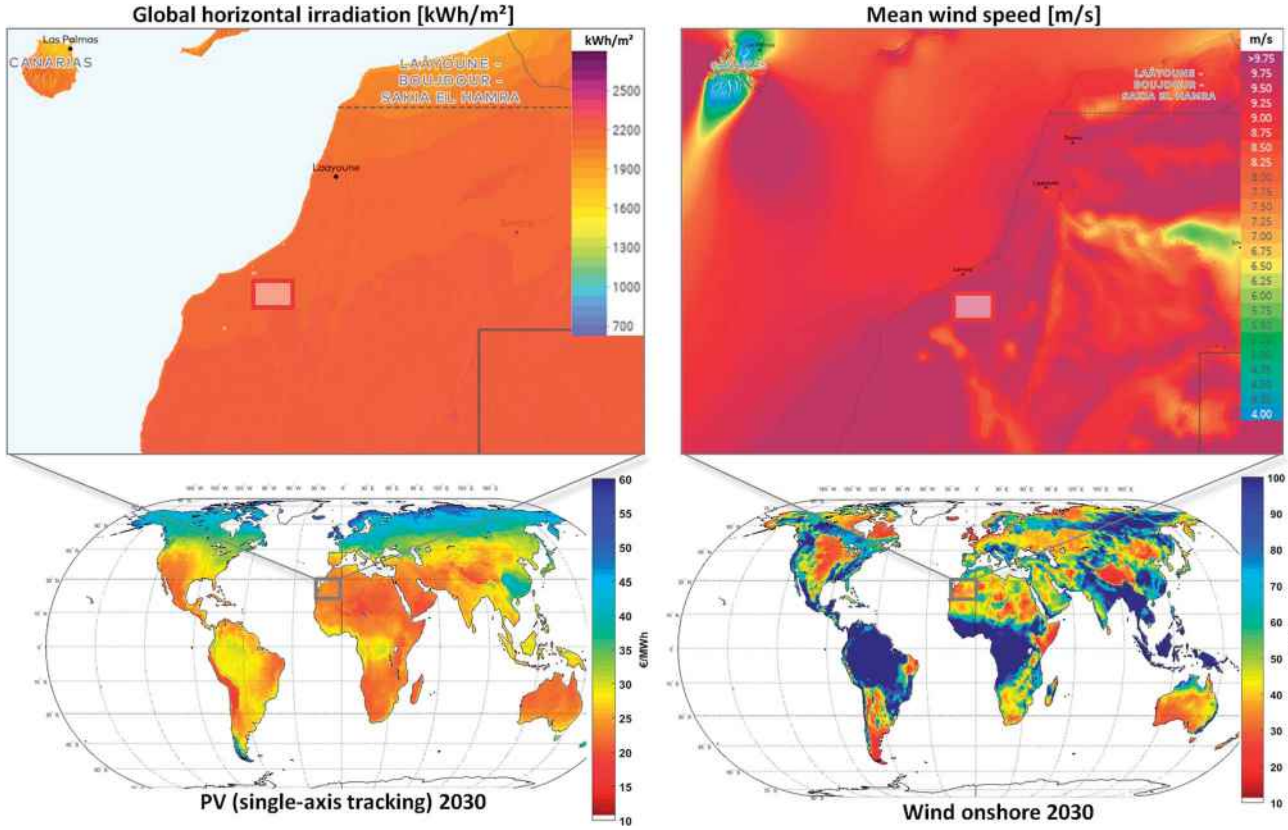

Fig. 4 Top: solar and wind potential map for south-west Morocco/Western Sahara (Global Solar and Wind Atlas 2.0 by Technical University of Denmark DTU[93,94]) bottom (based on Fasihi *et al.* 2020): 2030 global renewable electricity generation cost for PV 1-axis tracking and wind power (considering 2005 weather data and 7% weighted average capital cost).

hours (FLH) and global horizontal irradiation (GHI) with recent literature. For prospected wind energy generation cost in 2030 annual full load hours > 4000 h lead to cost varying between 20–40 € per MWh_{el}.[100] In case of PV in 2030 a global horizontal irradiation (GHI) of ~2000 kWh per (m^2 a) enables electricity production between 19–27 € per MWh_{el}. This cost range has been validated by a recent study of Fasihi *et al.* 2020, assessing the global levelised cost of electricity for wind and PV in 2030 (Fig. 4, bottom).[101] Therefore, for both, wind and PV electricity cost of 25 € per MWh_{el} have been considered for the economic calculations. The optimum installed capacities of RE, PEM electrolysis, H_2 motor and the cavern orientate on the determined production capacity of 42 500 t(H_2) per year and depend on the PtX pathway and its respective process parameters. The total installed capacities of wind and PV vary between 595 MW_p (LOHC–H_2) and 781 MW_p (CH_3OH). The share of installed PV *versus* wind capacities varies between 28–34%, highlighting the installation of wind turbines over PV modules. Shares within this range are representative for locations with high average annual wind speeds and have already been proposed by Fasihi *et al.* 2018 regarding an optimised electricity supply for remote PtX systems.[26] The use of solar-thermal electricity generation to increase full load hours could be taken into account in future studies.

The capacity of the PEM electrolysis varies between 453 MW_p (LOHC–H_2) and 584 MW_p (CH_3OH) since it depends on the pathways' electricity demand which is covered by H_2 during times of non-sufficient fluctuating RE. The LOHC–H_2 pathway is characterised by comparably low installed capacities for PEM electrolysis, H_2 motor and cavern because of few aggregates demanding electricity on a base-load. In turn, the CH_3OH pathway requires larger installed capacities due to a high thermal demand for the DAC units which has to be partially covered by electric heating. Due to production scale-up and advancing technological maturity, a significant reduction of electrolysis capital cost, especially in case of PEM electrolysis, can be assumed for the next decade placing this technology in the focus of future large-scale PtX applications.[34,102] For this case study, an investment of 600 € per kW_{el} has been assumed resulting from manufacturer estimations for state-of-the-art and future electrolysis systems.[34] The product storage capacities depend on the respective production rate, the ship's transport capacity and its two-way travel time. A safety margin of 20% for the storage capacity is assumed.

The shipping cost depend on ship type, transport capacity and the utilisation. The transport capacities are oriented to large conventional vessels with volumes of 140 000 m^3. The ascribed ship investment depends on the respective annual utilisation of the ships. For example, in case of the LOHC–H_2 pathway, the ship is utilised 44% of the year and assumed to be available for other transport tasks during the remaining time. For the LOHC–H_2 pathway a 50% reduced ship size (70 000 m^3;

Table 1 Installed capacities for the assessed PtX pathways. The capacities orientate on a constant conversion of 42 500 t H_2 per a into PtX products

Installed capacities	NH_3	LH_2	LOHC–H_2	LCH_4	CH_3OH
Renewables					
Wind installed capacity [MW_p]	506	506	453	509	578
Wind capacity factor	50%	50%	50%	50%	50%
PV installed capacity [MW_p]	144	172	142	153	220
PV capacity factor	27%	27%	27%	27%	27%
RE produced [GWh_{el} per a]	2573	2638	2331	2606	3067
RE utilisation factor PtX system					
RE cost [€ per MWh_{el}]	25	25	25	25	25
Seawater desalination					
Installed capacity [m^3 per a]	425 000	425 000	425 000	425 000	425 000
PEM electrolysis					
Installed capacity [MW_{el}]	440	450	419	446	481
Lifetime system [a]	20	20	20	20	20
Lifetime stack [a]	10	10	10	10	10
Replacement cost [% of CAPEX]	34%	34%	34%	34%	34%
H_2 motor					
Installed capacity [MW_{el}]	26.2	32.6	2	29	68
H_2 cavern					
Installed capacity [m^3]	608 410	631 980	516 430	630 240	756 230
ASU/DAC					
Installed capacity [t per day]	556	—	—	708	873
Synthesis (NH_3, CH_4, CH_3OH)					
Installed capacity [t per day]	667	—	—	241	612
Liquefaction (H_2, CH_4)					
Installed capacity [t per day]	—	120	—	241	—
(De-)hydrogenation set					
Installed capacity [t per day]	—	—	120	—	—
Product storage					
Installed capacity [t]	114 576	11 928	87 696	71 000	132 367
Shipping					
Assumed vessel type	LNG carrier	LH_2 carrier	Tanker	LNG carrier	Tanker
Transport volume [m^3]	140 000	140 000	70 000	140 000	140 000
Transport capacity [t product]	95 480	9940	73 080	59 167	110 306
Ship utilisation [% of year]	10%	17%	44%	6%	10%
Product amount at destination					
Total [GJ per a]	4 301 048	4 821 688	3 399 347	4 204 030	4 426 097

~73 100 t perhydro-DBT) has been assumed to limit the necessary amount of the LOHC-medium DBT. Reason is the high initial purchase cost of DBT ranging from 2–4 € per kg(DBT) (assumed: 2 € per kg(DBT)).[47]

Operating costs other than energy costs are calculated as a proportion of the respective investment costs and are described in detail in the ESI (ESI-S4†).

Economics for the analysed PtX pathways

Fig. 5 shows the production cost (in € per MWh_{LHV}) without and with shipping from Morocco to Germany for each PtX pathway. The components contain both the CAPEX depreciation and OPEX (excl. electricity). The price for the fossil reference product is indicated with a maximum and minimum spread based on available data (H_2: steam reforming of natural gas;[103,104] NH_3: conventional large-scale Haber–Bosch synthesis in Western Europe;[105] CH_3OH syngas based on natural gas;[106] natural gas: European Union natural gas import price[107]). The production cost including ship transport vary between 124 € per MWh_{LHV} (NH_3) and 156 € per MWh_{LHV} (LOHC–H_2) with LCH_4 showing the biggest cost difference to its fossil substitute (+705%). The PtX production cost are therefore clearly higher

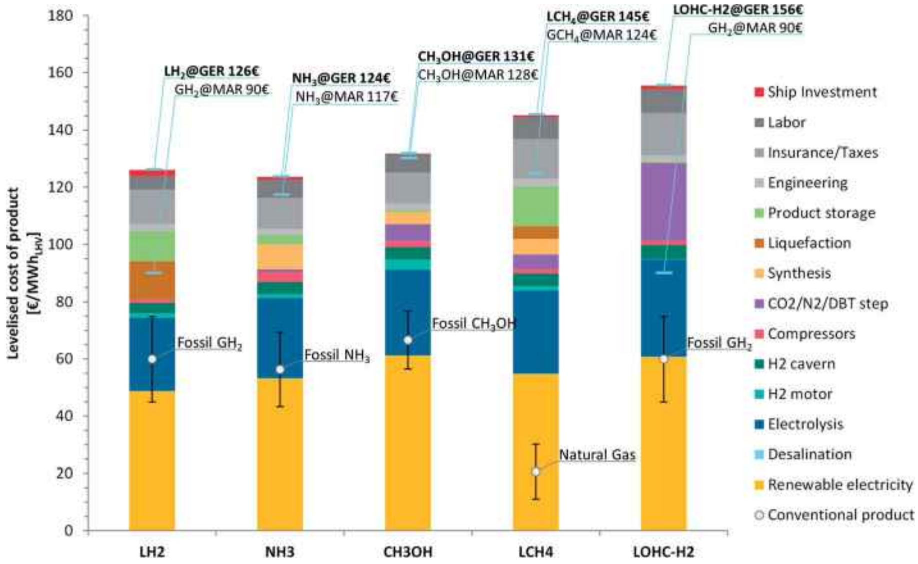

Fig. 5 Production cost of PtX-products ("@GER", incl. shipping Morocco – Germany) based on energy content (LHV). The product cost in Morocco ("@MAR") exclude the cost for shipping, product storage and liquefaction. Levelised cost for the conventional product indicated by including a respective maximum/minimum price spread based on available data.

than the fossil based reference product. That PtX products tend to be more expensive than their fossil counterparts is not a new finding of this study. The fact that, on the one hand, fossils are too cheap due to a missing inclusion of environmental and social costs and, on the other hand, general PtX production still being a technology and hence capital intensive undertaking has recently been discussed in preceding papers.[23,108–110] Assuming that the PtX products are already utilised at the PtX location, any cost for shipping, product storage and liquefaction can be excluded. In this case the cost for gaseous H_2 are significantly lower (90 € per MWh(H_2)) than the other PtX product costs.

It becomes obvious that for all PtX pathways, the electricity demand, mainly caused by electrolytic H_2 production, represents the major share of production cost (39–46%). Additionally, the capital and further operational cost of the PEM electrolysis contribute with a notable cost share (20–23%). For the LH_2 pathway the necessary liquefaction increases the production cost of LH_2 by 10%. The on-site product storages for LH_2, LCH_4 and NH_3, requiring a more complex construction due to high insulation efforts and boil-off reliquefaction, are characterised with higher specific investment than the tanks containing CH_3OH or LOHC. In case of the LOHC–H_2 pathway on-site storage cost are comparable to the CH_3OH pathway due to the practicable substance. However, the high initial purchase cost for the LOHC medium DBT (2 € per kg(DBT); 30% of CAPEX) drive the overall pathway cost. Further cost increase had been avoided due to the assumption of a smaller ship resulting in less DBT to be initially purchased. The consequent increase in ship utilisation and ascribed investment (a smaller ship has to travel more frequent for the same annual amount of delivered energy carrier) was however offset by the savings in reduced DBT purchase. A clear reduction of the DBT market price from currently ~4 € per kg(DBT) to the assumed 2 € per kg(DBT) poses a clear target for future application of DBT as long-distance H_2-carrier. Other discussed LOHC's such as *N*-ethylcarbazole or 1,2-dihydro-1,2-azaborine have even higher market prices.[41] This case study assumes an H_2 cavern as a temporary storage facility for H_2 acting as buffer between fluctuating RE generation and downstream steady-state process steps. In case that due to geological restrictions underground H_2 storage in a cavern is not possible CAPEX would be significantly increased due to the high necessary investment for pressurised pipe storage systems. In such a case, the dynamic operation of subsequent process steps can significantly reduce the H_2 storage demand and thus limit the respective investment. For the steady-state syntheses a dynamic operation is by now at low TRL and investigated at lab-scale within numerous research projects.[111–114]

For a better understanding how the production cost depend on key economic indicators, a variation of renewable electricity cost, electrolysis investment and the interest rate has been conducted. These three parameters have been identified as the major influencing among all economic and technological indicators. Fig. 6 shows the sensitivity for all PtX pathways. For a clear representation, the paths are represented in an averaged form. This enables a first discussion about the impact of the key economic indicators of all PtX pathways assessed. A more detailed sensitivity is included in the ESI (ESI-S5†). An increase of the renewable electricity price to 50 € per MWh_{LHV} (+200%) results in an increase of the averaged production cost to an average of 187 € per MWh_{LHV} (+39%). Levelised cost of renewable electricity around 50 € per MWh_{el} are already today representative for large parts of central Europe.[101,115] However, such PtX production cost are far from the market price due to the cheap fossil reference products. An increased PEM electrolysis investment of 1200 € per kW_{el} (+200%), a value which can be discussed as a realistic value for present PEM systems,[34,102] leads to averaged production cost of 172 € per MWh_{LHV} (+27%). Regarding a variation of interest to 10% production cost increase

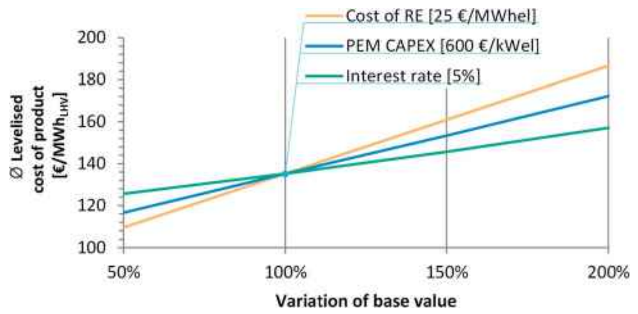

Fig. 6 Averaged levelised cost of PtX products depending on a variation of renewable electricity cost [base value = 25 € per MWh_{el}], PEM CAPEX [base value = 600 € per kW_{el}] and interest [base value = 5%].

to 157 € per MWh_{LHV}. The feasibility of RE projects and contract prices heavily depending on interest rates has recently been discussed in literature highlighting this factor as often underestimated.[116,117] Especially when assessing future or foreign RE projects the final estimation of project cost can be considerably undermined by diverging *real* interest conditions.

Additionally, to these key economic indicators, the ship transport distance has been varied. Fig. 7 shows the influence of the shipping distance on the production cost (top) and the cargo-specific shipping fuel demand (bottom). Since the ships use their own cargo as fuel, the cargo-specific ship energy demand describes the amount of energy carrier "consumed" to transport one MWh of energy carrier over the respective distance. To give an idea on global shipping distances exemplary routes from Morocco to the US American East Coast or to Japan are indicated. The graphs make clear that the LOHC–H_2 and LH_2 pathway are influenced the most by increasing transport distances. In case of the LH_2 pathway, reason for increased product cost is on the one hand an increase of on-site LH_2 storage demand for the times when the ship is on the move. On the other hand, the H_2 consumption caused by the ship itself drives the LCo(LH_2) since less product arrives at the final destination. In case of the LOHC–H_2 pathway, more DBT must be kept available as local storage medium for the times the ship is on the cruise. Even in the event that the LH_2 storage costs or the DBT market prices can be significantly reduced, the cargo-specific shipping fuel demand represents a cost factor whose influence should not be underestimated. CH_3OH and LCH_4 profit from higher volumetric energy densities and therefore require a smaller share of their stored cargo as fuel.

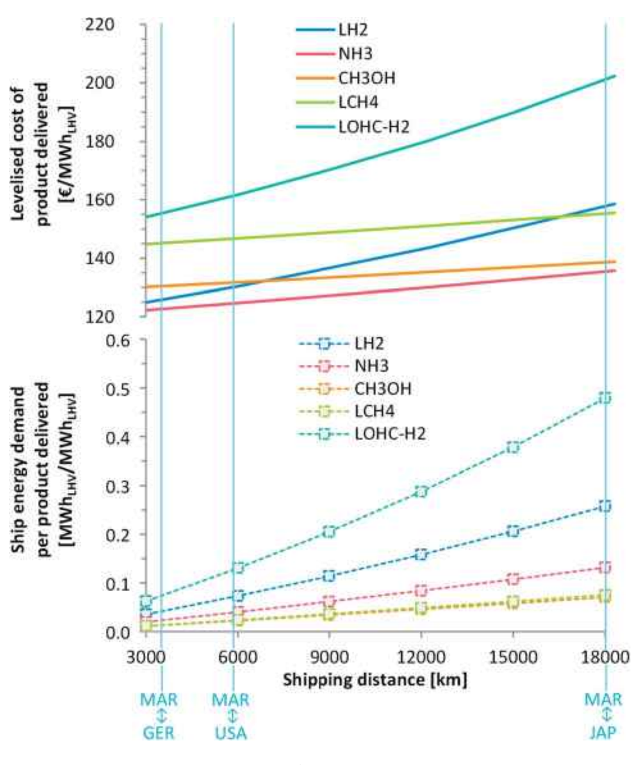

Fig. 7 Top: levelised cost of PtX-product depending shipping distance. Bottom: MWh of fuel demand per MWh of product delivered at final destination.

Conclusions

With this study we provide an overview on the energy and cost efficiency of five different PtX pathways. While the first part of the paper assessed the pathways respective overall efficiency differentiated by base and optimistic parameters, the second part devoted to production cost and a specific case study (Morocco/Western Sahara) considering more site and weather dependent factors.

In general, it can be concluded that the calculated differences in the pathways total efficiencies are not too significant. For all pathways, the H_2 providing water electrolysis acts as the main energy consumer. The reason for this is that the entire energy content of the final PtX product is provided by H_2, which is produced by water electrolysis. Hence, their electricity consumption shall not be seen as lost power but rather as a necessary transformation of renewable energy into a storable form of sustainable energy carrier. This aspect is an important reason why, to date, PtX pathways for energy carriers and fuels have tended to be less energy efficient than their fossil counterparts. The latter profit from a "free" sourcing of fossil stored hydrocarbons with high energy densities, in turn charge their indirect (environmental) cost in the form of massive greenhouse gas emissions. In order to improve PtX pathways' energy and cost efficiencies, a reduction of the electrolysis energy demand will be clearly beneficial in case high full load hours can be expected. However, R&D efforts by the electrolyser industry are more focused on a reduction of capital cost.[102] Reason is the higher share of capital cost for electrolysis systems operated with low-cost RE and at moderate full load hours.

The LH_2 pathway proved to be the most efficient of all evaluated process chains (52–58% overall efficiency). Although an energy intensive liquefaction is part of the process chain, the overall efficiency profits from not being dependent on CO_2- or N_2-sourcing. Large-scale ship transport of LH_2 is still in its pilot phase and has to be demonstrated within the coming years.[118] In terms of levelised cost of product, LH_2 (126 € per MWh@GER) is roughly on a par with the low production cost of NH_3 (124 € per MWh@GER) and

CH_3OH (131 € per MWh@GER). Furthermore, when focussing on potential end-user applications, using H_2 as a fuel offers high electrical conversion efficiencies (*e.g.* fuel cell based combined heat and power plants with $\eta_{el} \sim 60\%$ and $\eta_{el+th} \sim 85\%$).

The NH_3 pathway characterised by a comparable high pathway efficiency (48–52%) and low levelised cost of product, clearly benefits from a reduced energy demand for N_2 provision *via* ASU. However, final application of NH_3 as energy carrier or fuel is still at an early stage. Currently, energy-intensive NH_3 cracking for H_2 recovery at the point of use appears to be the most realistic route. With further technological advances either on the side of direct NH_3 application as fuel[82,83] or in terms of NH_3 cracking at lower temperatures and with alternative catalysts[119,120] this pathway can be very promising for large-scale and long-distance energy transport and utilisation.

The overall efficiency of the CH_3OH (40–44%) and LCH_4 pathway (44–49%) clearly increase in case CO_2 can be sourced from a concentrated stream (4–10% increase in total efficiency). If CO_2 shall be sourced from the atmosphere, the availability of additional excess or solar thermal heat to cover the necessary DAC desorption energy demand raises the pathway efficiencies. In terms of LCH_4 production cost (145 € per MWh@GER) the pathway has to deal with high capital costs for cryogenic storage and a cheap market price of the competing fossil natural gas. Furthermore, when considering the production, distribution and utilisation of synthetic CH_4 at large scales, the high global warming potential of this gas must be critically considered. Both, LNG and methanol are already globally traded on large scales (317 and 75 Mt per year, respectively[121,122]), with methanol profiting from a less complex infrastructure for transport and distribution.

The LOHC–H_2 pathway is characterised by high initial investment for the LOHC medium DBT (2 € per kg(DBT) assumed) and the high thermal demand for the dehydrogenation step at the final destination (25–30% of $H_{2,LHV}$ assumed). In case excess heat integration for dehydrogenation is possible, the LOHC pathway significantly increases its overall efficiency (16–18% increase in total efficiency). One idea could be the integration of excess heat from a downstream H_2 based combined heat and power plant. However, such integration is case-dependent and only possible if H_2 is utilised at the point of dehydrogenation.

Besides renewable electricity, the access to water presents a crucial aspect of large-scale PtX processes. The efficiency analysis (as well as the cost analysis) showed that for arid regions water provision *via* seawater reverse osmosis can be very promising. The specific energy demand and attributed costs are low. However, it should be noted that for large plants a disposal system for the resulting brine must be included without increasing the pressure on the marine environment.[123,124]

When comparing our assessment to the other PtX import studies assuming even better RE generation locations (*e.g.* Patagonia or South West Australia) it gets clear that PtX production costs can be even further reduced due to even higher full load hours. The integration of less fluctuating solar-thermal electricity generation and small-scale battery storage could present a way to reduce storage demands. This is an important aspect for PtX locations without the possibility for H_2 storage in caverns.

In summary, it can be concluded that the long-distance transport of renewable electricity in the form of PtX products is an important step towards defossilised global societies. However, before the great hope for a defossilisation of global societies is placed solely on cheap imported PtX energy sources, other strict measures should be continued in parallel. Aspects in this context are an increased eco-sufficiency, a significant reduction in transport, the use of regionally available RE potentials and, where reasonable, the direct electrification in combination with batteries. In any case, both the direct and indirect electrification of our currently fossil-fuelled societies will require large amounts of renewable energy, which for many countries cannot be fully covered by locally available RE plants. The ongoing market ramp-up of H_2 technologies and steadily increasing technological readiness levels lead to a constant reduction in costs at all PtX levels. Imported renewable energy in the form of PtX products is not a far-off future vision. They will enable the urgent step towards a defossilisation of sectors such as the heavy-duty, marine traffic, aviation and (petro-) chemicals industry at acceptable costs.

In any case, the export of large RE and PtX capacities from promising RE countries must also contribute to the defossilisation of the local energy system. The local population should benefit from the added value and environmental regulations should be strictly respected. This is the only way to avoid the significant deficits associated with the current global trade of fossil fuels.

Conflicts of interest

There are no conflicts to declare.

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VDV Die Verkehrsunternehmen

VDV | GFT, KB, T3, T4

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Stellungnahme zum Öffentlichen Fachgespräch „Alternative Antriebsstoffe“

Der Verband Deutscher Verkehrsunternehmen (VDV), Branchenverband für rund 600 Unternehmen des Öffentlichen Personen- und Schienengüterverkehrs begrüßt die Beratungen im Parlamentarischen Beirat für nachhaltige Entwicklung zum Thema „Alternative Antriebsstoffe“. Denn diese und andere Initiativen tragen mit dazu bei, dass die Förderkataloge für die Umstellung der Flotten auf alternative Antriebe auch für Busse und Bahnen offen stehen. So sind dank der breiten Unterstützung von Bund und Ländern inzwischen 2.000 Linienbusse mit alternativen Antrieben in Betrieb. Für weitere 1.400 saubere Busse haben unsere Mitgliedsunternehmen bereits Förderanträge gestellt, die teilweise schon bewilligt sind. Aber auch im Eisenbahnverkehr gewinnen emissionsarme und -freie Antriebe zunehmend an Bedeutung; etwa in Teilbereichen die nicht elektrifziert sind oder auch bei Werks- und Hafenbahnen.

Für die Fortsetzung dieser erfolgreichen Entwicklung ist es wichtig, dass die Förderkataloge auch in Zukunft technologieoffen bleiben. Denn während sich etwa batterieelektrische Antriebe im Stadtverkehr als praxistauglich erweisen, eignen sich im Überlandverkehr eher Erdgas- oder Dieselhybridbusse; aber auch die Wasserstofftechnologie. Für *kurzfristig* messbare Effekte bei Umwelt- und Klimaschutz ist es ferner sinnvoll, auch die Beschaffung von Bussen mit moderner Dieseltechnologie und die Nutzung von **synthetischen Kraftstoffen** voranzutreiben. Mit den jüngsten Änderungen des Deutschen Bundestages (Drucksache 19/29196) am Gesetzentwurf „zur Umsetzung der Richtlinie (EU) 2019/1161 vom 20. Juni 2019 zur Änderung der Richtlinie 2009/33/EG über die Förderung sauberer und energieeffizienter Straßenfahrzeuge sowie zur Änderung vergaberechtlicher Vorschriften“ wurde diesen Anforderungen Rechnung getragen. Hiermit wurde unter anderem festgeschrieben, dass in Zukunft auch emissionsarme und synthetische Kraftstoffe in Deutschland Verwendung finden dürfen. Demnach können zukünftig auch Dieselbusse ohne weiteres mit synthetischen und emissionsarmen Kraftstoffen betankt und betrieben werden. Kostenbelastungen für die andernfalls nötige Neubeschaffung von Bussen mit anderen alternativen Antriebstechnologien können so vermieden werden. Aber auch der Umgang mit zwei oder mehr verschiedenen Antriebssystemen auf einem Betriebshof ist durch diese wichtige Freigabe von synthetischen Kraftstoffen nun nicht mehr nötig.

Für die Umsetzung ist jedoch ein zweiter Schritt nötig; nämlich eine Änderung der „Zehnten Verordnung zur Durchführung des Bundes-Immissionsschutzgesetzes“ (**10. BImschV**). Hintergrund ist, dass die BImschV gegenwärtig noch keine Nutzungsmöglichkeit für synthetische Kraftstoffe im Linienbusverkehr vorsieht. So könnte mit folgender Formulierung diese Lücke in **§ 4 (1)** geschlossen werden:

> „Dieselkraftstoff darf nur dann gewerbsmäßig oder im Rahmen wirtschaftlicher Unternehmungen gegenüber dem Letztverbraucher in den Verkehr gebracht werden, wenn er den Anforderungen der DIN EN 590, Ausgabe Oktober 2017 *oder der DIN EN 15940 genügt sofern dieser für den Linienbusverkehr genutzt wird.*“

Vor allem für Verkehrsunternehmen in ländlichen Räumen spielt diese Änderung und damit die Nutzungsmöglichkeit von emissionsarmen und synthetischen Kraftstoffen eine wichtige Rolle, weil viele andere alternative Technologien im Überlandverkehr noch keine ausreichenden Reichweiten haben.