ONGC DECARBONIZATION ROADMAP

Strategy for achieving Net-Zero Operational Emissions (Scope 1 & Scope 2) by 2038

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MESSAGE

India's role in the global energy landscape is progressively becoming pivotal, and is likely to account for 25% of global energy demand growth over the next two decades. Further, according to International Energy Agency, India's share in global primary energy consumption is expected to rise to 9.8% by 2050. Our journey emphasizes the complex challenges faced by a rapidly developing nation. While the country's Net Zero target is 2070, ONGC is committed to realise Scope-1 and Scope-2 (operational emission) Net Zero by 2038.

A roadmap has been developed, considering the projected operational emissions for ONGC until FY 38. The roadmap incorporates a series of De-carbonization levers strategically spread across short, medium, and long-term horizons. These levers are designed to address various aspects of ONGC's operations, ensuring a comprehensive and phased approach to emission reduction. This report covers systematic approach to achieve ONGC's De-carbonization goal by 2038. With increasing energy demand, our commitment to De-carbonization is stronger than ever. ONGC has made significant contribution in reducing gas flaring in our E&P operations, aligning with our environmental commitments; we have consistently worked to bring it lower and lower, and we aim to bring avoidable flaring down to zero by 2030. Similarly, substantive reduction has been achieved in the area of Methane emission, and we aim to bring it down to zero level by 2030.

ONGC is committed to prioritize De-carbonization efforts and transitioning towards cleaner energy sources. In order to strengthen ONGC's green portfolio, **"ONGC Green Limited"** has been incorporated as wholly owned subsidiary to engage into the business of value-chains of energy business viz. renewable energy, bio-fuels/biogas business, green hydrogen and its derivatives, carbon capture utilization and storage etc.

With Government of India's impetus towards providing affordable energy in a sustainable manner, this roadmap is an attempt to successfully navigate the energy trilemma of energy availability, affordability and sustainability of country's ever-growing energy needs. Together, let us build a sustainable and resilient energy future for India and mother planet.

(Arun Kumar Singh)

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MESSAGE

ONGC is continuously enhancing its operations to align with its commitment to achieving Net Zero status by 2038. In the energy sector, ONGC positioned itself at the forefront of clean energy solutions in India by championing hydrogen production and utilization.

A roadmap has been developed, considering the projected Scope 1 and Scope 2 emissions for ONGC until FY 38. The approach aligns with global efforts to combat climate change and positions ONGC as a responsible and sustainable player in the energy sector. The roadmap incorporates a series of De-carbonization levers such as RE, ZRF, CCUS, Compressed Biogas, Green Hydrogen, EVs and BESS strategically spread across short, medium, and long-term horizons. These levers are designed to address various aspects of ONGC's operations, ensuring a comprehensive and phased approach to emission reduction. This report covers systematic approach to achieve ONGC's De-carbonization goal by 2038. This also covers development of internal carbon pricing which will assist in taking financial decisions for the De-carbonization roadmap. Life cycle assessment of major products is also conducted.

ONGC has also announced the incorporation of a wholly owned subsidiary, **"ONGC Green Limited"** which will focus on green energy and the gas business. ONGC is already planning a 5 GW renewable energy project in Rajasthan and 1 million tonne per annum green ammonia plant in Mangalore.

Through its commitment to innovation, ONGC remains at the forefront of achieving growth in a sustainable manner through research and development, setting benchmarks for sustainability in the industry. ONGC also strives to provide its support at contributing to the nation's journey towards a sustainable future.

Sushma Rawat

(Sushma Rawat)

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1.1. Introduction

India, in alignment with global efforts to combat climate change, has committed to achieving Net Zero emissions by 2070, with focus on reducing the emissions intensity of its GDP by 45% by 2030 and attaining 50% cumulative electric power capacity from non-fossil fuel sources. The Oil and Gas industry, a key player in India's economy, is pivotal in this transition. The industry's participation is crucial for India's journey towards a more diverse and sustainable energy mix, reducing reliance on traditional fossil fuels. Recognizing the urgency, ONGC, a major player in the Indian oil and gas sector, has set an ambitious goal to achieve Net Zero operational Emissions for Scope 1 and Scope 2 by 2038. This report offers a comprehensive analysis of ONGC's roadmap towards the decarbonization of its operational emissions (Scope 1 and 2), based on Science Based Targets Initiatives (SBTi), showcasing its commitment to aligning with India's sustainable energy objectives.

1.2. GHG baseline emissions for FY 21-22

The baseline emissions for Scope 1 and Scope 2 operational emissions for the year FY 21-22 have been calculated, providing a foundational reference for our future emission projections. Scope 1 emissions, covering direct emissions from owned or controlled sources, and Scope 2 emissions, which include indirect emissions primarily from the generation of purchased electricity,have been quantified to establish this baseline. This critical data serves as the cornerstone for developing comprehensive strategies and targets for emission reductions.

Table 1 GHG baseline emissions

S No.	GHG operational baseline emissions	(Million tCO2e)	
1	Scope 1 emissions	8.81	
2	Scope 2 emissions	0.19	
3	Total operational emissions (Scope 1 + 2)	**9.00**	
4	Scope 3 emissions (Supply chain emissions)	24.30	
5	Grand Total (Scope 1 + 2 + 3)	**33.30**	
S No.	**Emission Sources (Scope 1)**	**(Million tCO2e)**	**%**
1	Captive Power Generation (Natural Gas)	4.40	49%
2	Fuel Combustion- Heating and CHP (Natural Gas)	1.32	15%
3	Gas Flaring	1.22	14%
4	Diesel	0.94	10%
5	Acid Gas Venting	0.54	6%
6	Fugitive Emissions	0.36	4%
7	ATF	0.02	0%
S. No.	**Emission Sources (Scope 2)**	**(Million tCO2e)**	**%**
8	Grid Electricity Purchase	0.19	2%
Total		9.00	100 %

Scope 3 Emissions Categories	(Million tCO2e)
Category 1 - Purchased goods and services	1.90
Category 2 - Capital goods	0.09
Category 3 - Fuel- and energy-related activities	0.05
Category 4 - Upstream transportation and distribution	0.04
Category 6 - Business travel	0.01
Category 7 - Employee commute	0.02
Category 9 - Downstream transportation and distribution	1.55
Category 10 - Processing of sold products	17.06
Category 11 - Use of sold products	3.53

In terms of Scope 1 emissions, ONGC contributes a total of 8.81 million tonnes of carbon dioxide equivalent (tCO2e), with the major sources being captive power generation (49%), fuel combustion (15%), gas flaring (14%), and fugitive emissions (4%). On the other hand, Scope 2 emissions, totalling 0.19 million tCO2e, mainly stem from grid electricity purchases. For Scope 3 emission inventorization Categories 5,12,13,14,15 are not significant to the operations of ONGC. Category 9,10 and 11 contribute to 91.29 % of the total Scope 3 emissions.

1.3. Operation wise GHG baseline emissions for FY 21-22

Scope 1 emissions (direct GHG emissions), emanate from various business operations: with contributions from plants, onshore and offshore assets, basins, institutes, and services. Offshore assets account for the largest share, releasing 4.77 million tCO2e, while onshore assets contribute 1.2 million tCO2e and plants release 1.04 million tCO2e. The impact of basins, institutes and services is comparatively minor, together at 1.79 million tCO2e. The source of Scope 2 emissions (Indirect emissions) is grid electricity. Onshore and offshore assets, plants, basins, and institutes collectively contribute 0.19 million tCO2e. Notably, onshore, and offshore assets are responsible for the most of these emissions, releasing 0.12 million tCO2e and 0.01 million tCO2e, respectively. The remaining contributions are from plants, services, basins, and institutes, totalling 0.01 million tCO2e, and 0.05 million tCO2e.

Table 2 GHG missions in ONGC Operations

Scope 1 Emissions		
Classification	Million tCO2e	**% Contribution**
Assets (Offshore)	4.77	54.14
Assets (Onshore)	1.21	13.73
Plants	1.04	11.80
Others (Services, basins, institutes)	1.79	20.31
Total	**8.81**	

Scope 2 Emissions		
Classification	Million tCO2e	**% Contribution**
Assets (Offshore)	0.01	5.26
Assets (Onshore)	0.12	63.15
Plants	0.01	5.26
Others (Services, basins, institutes)	0.05	26.31
Total	**0.19**	

1.4. Decarbonization roadmap

The decarbonization roadmap represents a strategic initiative aimed at achieving a milestone of zero operational (Scope 1 and Scope 2) emissions by the Fiscal year 2038. The roadmap has been developed, considering the projected Scope 1 and Scope 2 emissions for ONGC until FY 38. This approach aligns with global efforts to combat climate change and positions ONGC as a responsible and sustainable player in the energy sector.

As per the GHG inventorization, Category 9,10 and 11 contributes to 91.29 % of the total Scope 3 emissions, which is coming from downstream processing/use of the sold products. These Scope-3 emissions of ONGC are Scope 1 emission of downstream companies.

Since Indian Oil & Gas downstream companies have set their Net Zero Target between 2040-2050 e.g GAIL(2040), IndianOil(2046); this will help ONGC to achieve its Scope-3 reduction targets.

Through a systematic deployment of various decarbonization measures, ONGC's pathway showcases a decline in emissions, affirming the pledge for net zero operational emissions (Scope 1 and Scope 2) by 2038:

Figure 1 ONGC decarbonisation roadmap

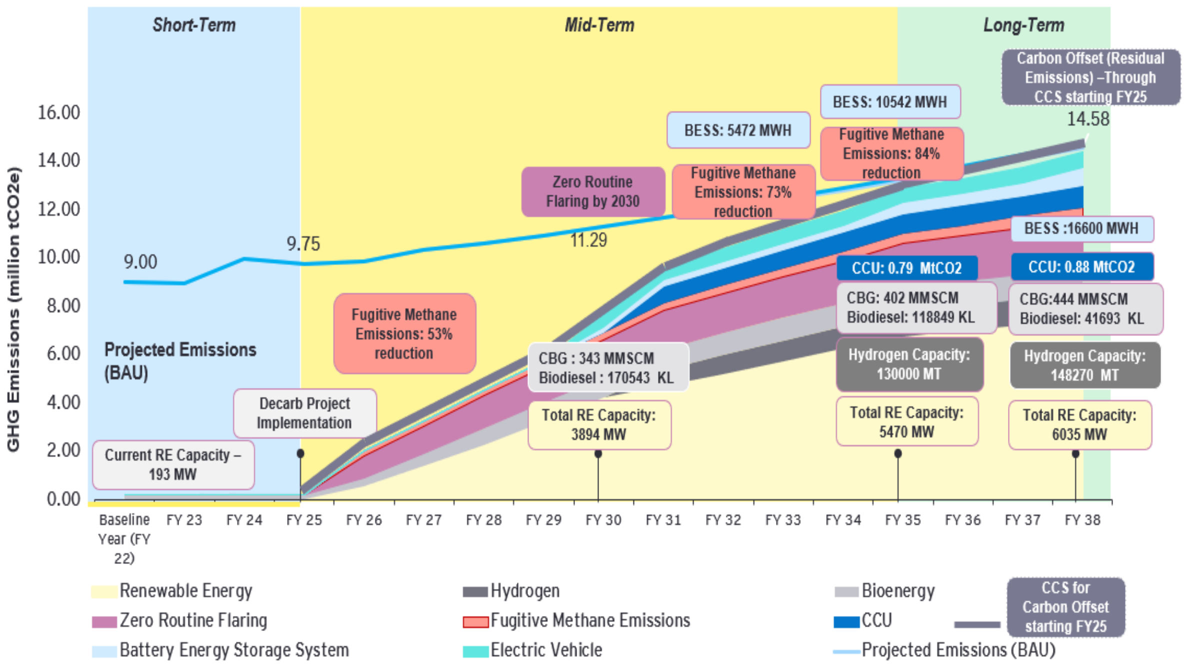


Table 3 Decarbonisation levers depicted over short, mid and long term scenarios.

Scope 1 and 2 Levers (Operational Emissions)	Short Term	Short to Medium Term (By FY 30)	Medium to Long Term (By FY 35)	Long Term (By FY 38)
Renewable Energy	**1) Pre-feasibility studies/survey for all capacities and targets** **Identification of suitable location and land acquisition** **Collaboration with State government and technology providers** *RE Hybrid: 30% Solar and 70% Wind	**Intervention:** 3.894 GW of RE Hybrid, Offshore wind and Small Hydro at Gujrat, Maharashtra, Andhra Pradesh, Tamil Nadu, and Assam.	**Intervention:** 5.470 GW of RE Hybrid, offshore wind and small Hydro at Gujrat, Maharashtra, Andhra Pradesh, Tamil Nadu, and Assam.	**Intervention:** 6.035 GW of RE Hybrid, offshore wind and small hydro at Gujrat, Maharashtra, Andhra Pradesh, Tamil Nadu, and Assam. **Required CAPEX:** Approx INR 48,810 Cr.

Capacity for RE Hybrid (MW)			
Location	Year		
	By 2030	By 2035	By 2038
Gujarat	607	711	801
Maharashtra	2422	2841	3121
Tamil Nadu	22	26	28
Andhra Pradesh	157	182	195
Capacity for Offshore Wind (MW)			
Location	Year		
	By 2030	By 2035	By 2038
Andhra Pradesh	15	40	46
Maharashtra	606	1597	1759
Capacity for Small Hydro (MW)			
Location	Year		
	By 2030	By 2035	By 2038
Assam	65	77	85

CAPEX			
Location	Year		
	By 2030	By 2035	By 2038
Andhra Pradesh	11483	17189	18950
Maharashtra	235389	411487	414835
Gujrat	34555	40500	44651
Tamil Nadu	1255	1470	1621
Assam	6214	7283	8030
Total Capex in Mn INR	**288896**	**477928**	**488087**

Scope 1 and 2 Levers (Operational Emissions)	Short Term	Short to Medium Term (By FY 30)	Medium to Long Term (By FY 35)	Long Term (By FY 38)
Compressed biogas and biodiesel	Collaboration with potential players, start-ups, strategic investments and partnerships.	Intervention: CBG capacity of 343 MMSCM and biodiesel capacity of 170543 KL would be required by 2030 leading to a proposed reduction of 0.87 million tCO_2e.	Intervention: CBG Capacity of 402 MMSCM and biodiesel capacity of 118849 KL would be required by 2035 leading to a reduction of 0.97 million tCO_2e.	Intervention: CBG Capacity of 444 MMSCM and biodiesel capacity of 41693 KL would be required by 2038 leading to a reduction of 1 million tCO_2e.
Flaring	Identification of suitable technology and implementation	Intervention: Zero Routine Flaring proposed by 2030 that shall lead to a reduction of 1.53 million tCO_2e. Key Identified Projects: As per evolving technology trends and market practices.	Intervention: Zero Routine Flaring proposed by 2030 that shall lead to a reduction of 1.80 million tCO_2e.	Intervention: Zero Routine Flaring proposed by 2030 that shall lead to a reduction of 1.98 million tCO_2e.
Fugitive Methane Emissions	Establishment of robust monitoring	Intervention: Reduction of Fugitive	Intervention: Reduction of Fugitive methane Emissions	Intervention: Reduction of Fugitive

	system, and use of technology to plug-in leakages.	methane emissions shall lead to a reduction of 0.31 million tCO2e.	shall lead to a reduction of 0.44 million tCO2e.	methane Emissions shall lead to a reduction of 0.53 million tCO2e.
Green Hydrogen Capacity	Collaboration with potential players, start-ups, strategic investments and partnerships.	Interventions: - Resource assessment, project identification and market consultations	Intervention: Green Hydrogen capacity of 0.13million MT is proposed by 2035 that shall lead to a reduction of 1.03 million tCO2e.	Intervention: Green Hydrogen capacity of 0.15 million MT is proposed by 2038 that shall lead to a reduction of 1.14 million tCO2e.
			Key Identified Project: Power requirement for 1 MMT per day of hydrogen production is 1.15 GW (Approx), to be achieved by equivalent RE. Source	
CCU	Capacity building, market review and vendor consultations	Applicability: Plants for Emissions from Acid Gas Venting	CCU capacity of 0.79 million tCO2e proposed by 2035.	CCU capacity of 0.88 million tCO2e proposed by 2038.
Battery Energy Storage System (BESS)	Market review, vendor consultations.	Battery Energy Storage System of capacity 5472 MWH leading to a proposed reduction of 0.24 million tCO2e.	Battery Energy Storage System of capacity 10542 MWH by 2035 leading to a proposed reduction of 0.48 million tCO2e.	Battery Energy Storage System of capacity 16600 MWH by 2035 leading to a proposed reduction of 0.76 million tCO2e.
EV	EV shall replace existing Diesel based logistics vehicles in all operations	Reduction of Emissions through EV to be 0.51 million tCO2e.	Reduction of Emissions through EV to be 0.59 million tCO2e.	Reduction of Emissions through EV to be 0.66 million tCO2e.

Carbon Offsets	Carbon offset of residual emissions through CCS starting FY25 in phase wise manner. Nature based solutions; afforestation may also be undertaken.	Phase-1	Phase-2	Phase-3

1.5. Internal Carbon Pricing

Implementing Internal Carbon Pricing (ICP) is a strategic move that empowers a company in its pursuit of decarbonization by targeted year. It allows the company to meticulously assess the cost associated with each ton of CO2 equivalent emitted, employing methods such as Implicit Pricing. By incorporating ICP into its business strategy, a company gains a comprehensive understanding of the per-ton cost required to meet its decarbonization targets.

Internal Carbon Pricing serves as a catalyst for an organization's commitment to environmental responsibility, positioning the corporation as a conscientious and forward-thinking entity. Beyond mere compliance, this proactive stance enables a company to drive innovation, attract sustainable investments, and contribute to economic growth.

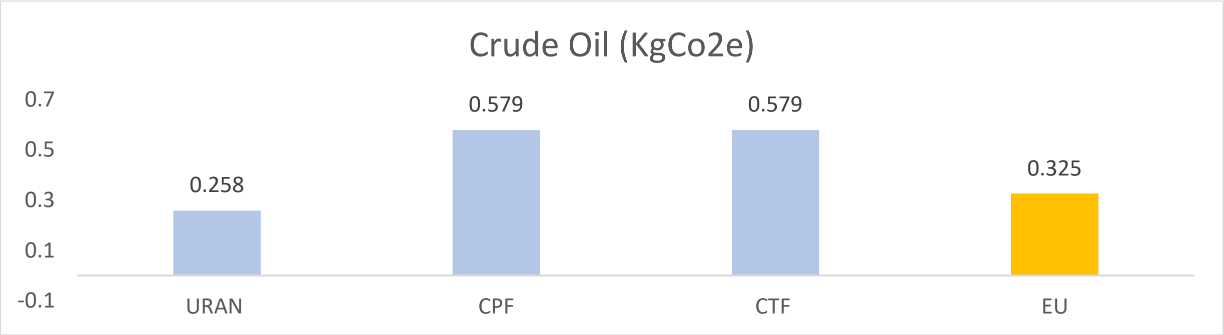
1.6. Life Cycle Assessment of GHG Emissions for major products

The scope of a Life Cycle Assessment (LCA) to be performed at selected sites covers various major products. These products are integral to the operations of ONGC (Oil and Natural Gas Corporation), and the LCA aims to evaluate the environmental impact associated with the entire life cycle of these products. The major products selected for the LCA include Crude Oil, Natural Gas, LPG,Propane,Naphtha, Kerosene and ATF.

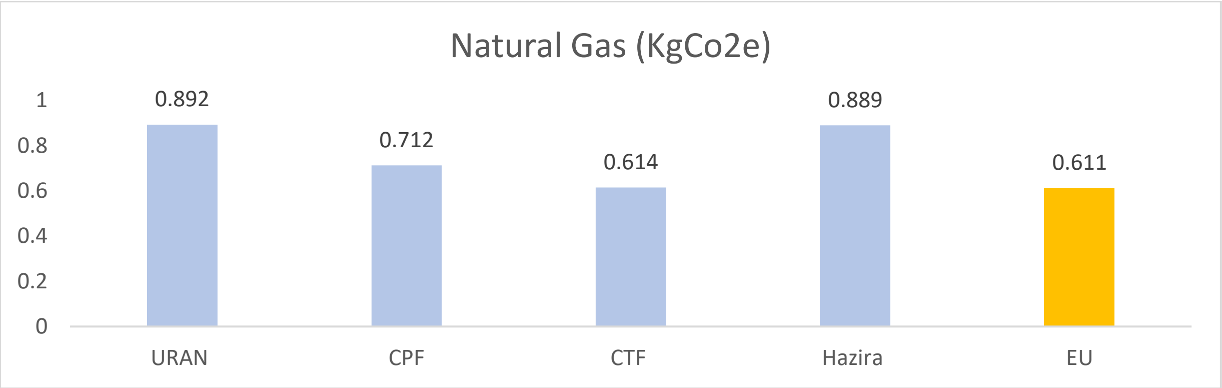
Benchmarking of Products:

Benchmarking of products are done on the impact category of "Climate Change - KgCO2eq/Kg of Product."

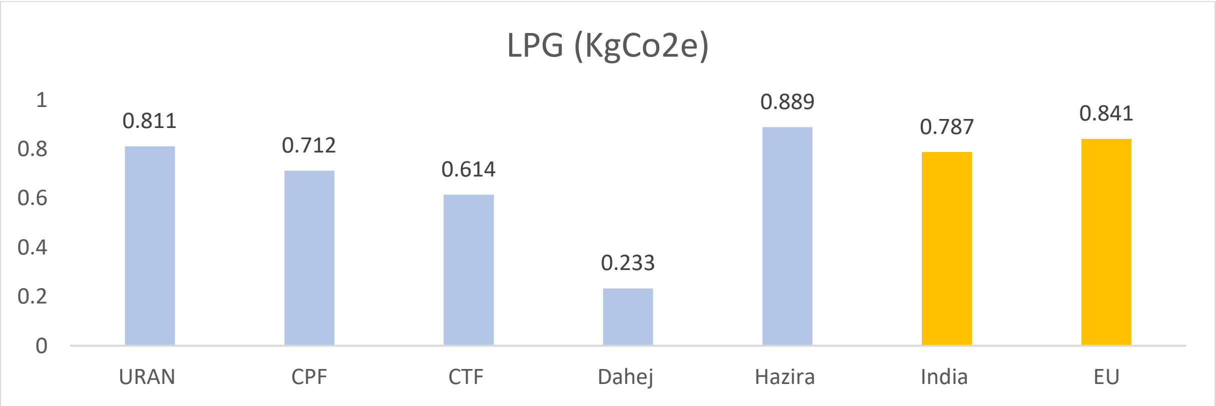
1. Crude Oil



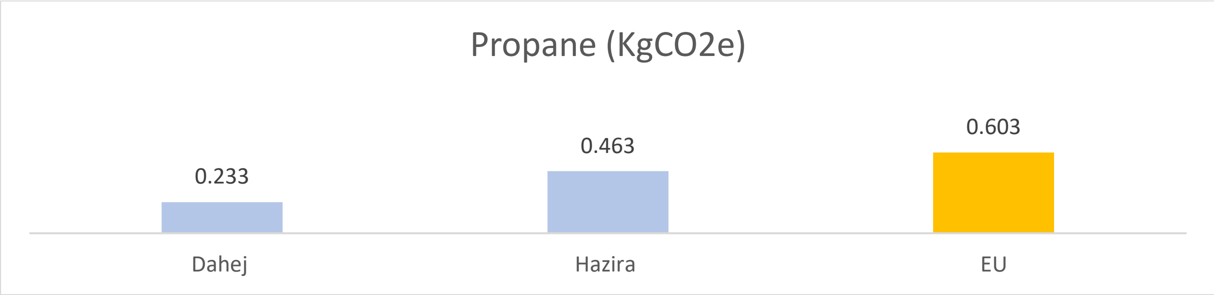
2. Natural Gas



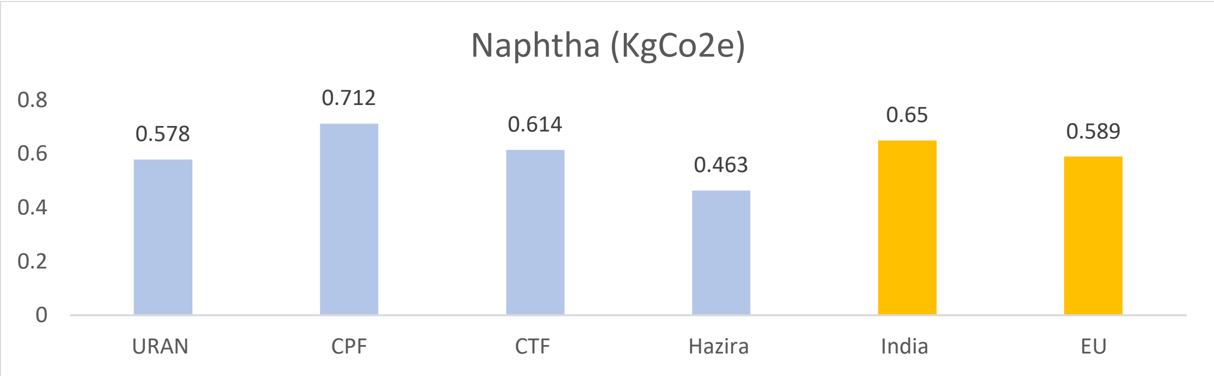
3. LPG



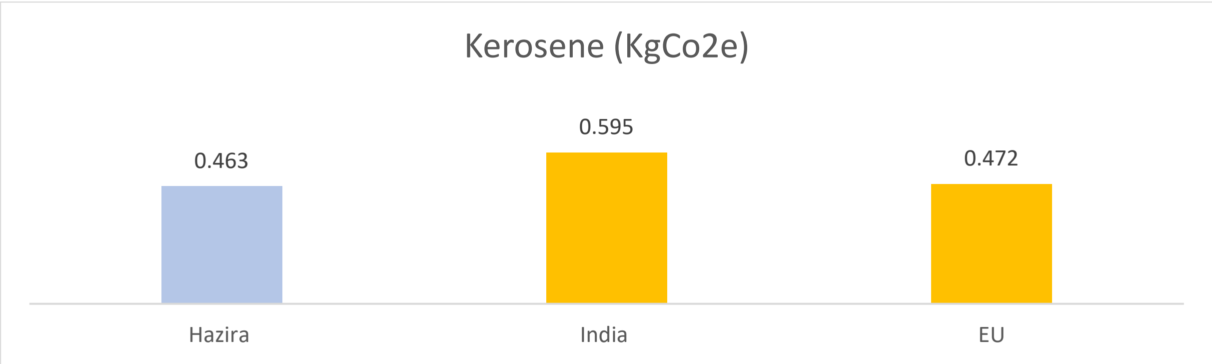
4. C3 (Propane)



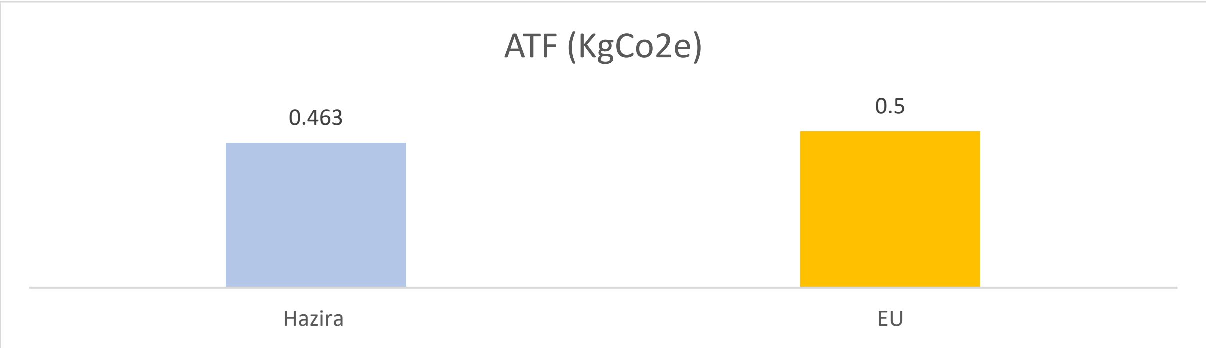
5. Naphtha



6. Kerosene



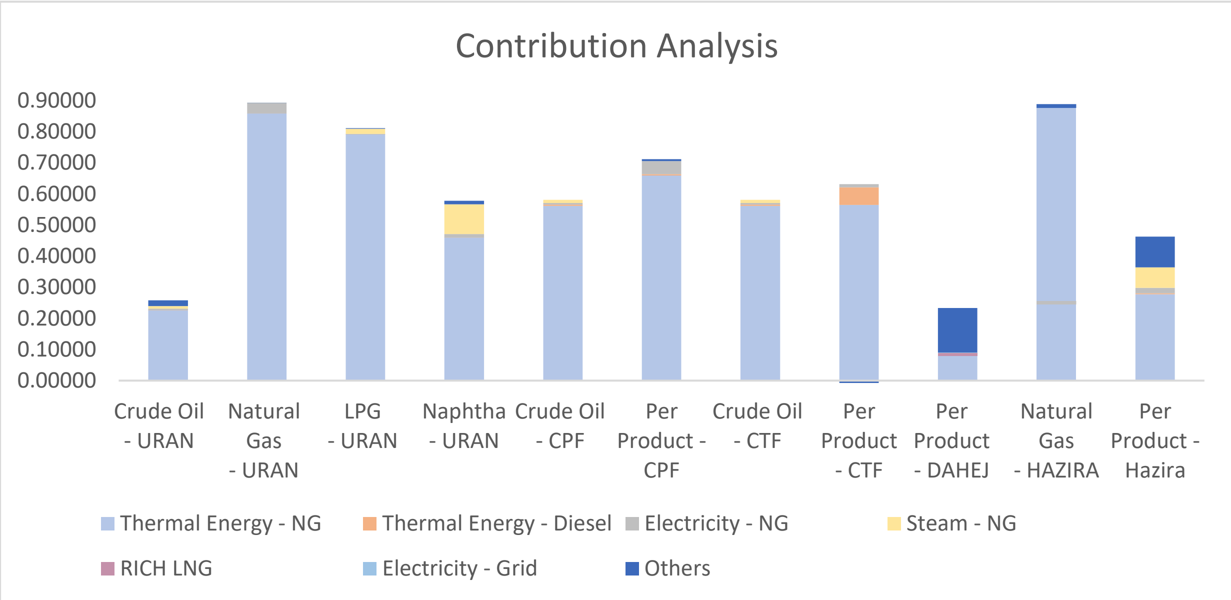
7. ATF



Contribution Analysis

The contribution analysis in the Life Cycle Assessment (LCA) study reveals the sources of emissions within each product category. This means that the study identifies and assesses which factors or components are responsible for generating emissions within specific product groups.

The GHG emissions contribution as "KgCO2eq. per Kg of Product" from the each of the processing facilities are outlined in the below graph and table.



1.7. Scope of Work Referencing

Deliverables as per Scope of Work	Section
ONGC's GHG inventory (scope 1,2,3) along with details on boundary and collection methodologies.	Chapter 3
Excel based data management system for inventorization.	Chapter 3 : Section 3.5
Short-, medium- and long-term targets for emission reduction. Formulate strategies for ONGC to comply with the COP-26 commitment.	Chapter 4 Chapter 5 Chapter 6 Chapter 7 Chapter 8 Chapter 9 Chapter 10 Chapter 11 Chapter 12 Chapter 13
Internal Carbon Pricing Mechanism for ONGC.	Chapter 14
Conduct Life Cycle Assessment of major 6 products: Crude Oil, Natural Gas, Processed Natural Gas, C2-C3 Mix , LPG, Naphtha, ATF, Kerosene, Diesel, Ethane, Propane, Butane	Refer Life Cycle Assessment Report (Annexure 9)

2. Introduction to Net-Zero

2.1. Why Net Zero?

The imperative for achieving a state of Net-Zero carbon dioxide (CO_2) emissions arises from the significant impact of greenhouse gases, particularly CO_2, on the escalating global warming crisis. The combustion of fossil fuels releases CO_2 and other pollutants, disrupting the delicate balance of the Earth's climate system, thereby intensifying the natural greenhouse effect essential for maintaining temperatures above freezing. The observed global warming, which has exceeded 1.1°C above pre-industrial levels, indicates a pressing need for substantial reductions in greenhouse gas emissions. Projections from the Intergovernmental Panel on Climate Change (IPCC) underscore the trajectory towards exceeding the critical 1.5°C Paris Agreement threshold by 2040 if immediate actions are not taken. The consequences manifest in a series of extreme weather events, such as heatwaves, intense precipitation leading to floods, coastal erosion, and other climate extremes. This underscores the urgent need for pragmatic and transformative actions to mitigate the impacts of global warming.

The core of the Net-Zero imperative lies in aligning with the Paris Agreement's goal of restricting global temperature increase to 1.5°C. The pragmatic assessment by Climate Action Tracker, predicting a 2.4°C rise, underscores the need for immediate and sustained efforts to avert catastrophic consequences.[1]

As per the University of Oxford, Net-Zero refers to a state in which the greenhouse gases (GHGs) going into the atmosphere are balanced out by removal of GHGs out of the atmosphere. On the other hand, the Science based Target Initiative defines corporate Net-Zero as:

1. Reducing scope 1, 2, and 3 emissions to zero or to a residual level that is consistent with reaching Net-Zero emissions at the global or sector level in eligible 1.5°C-aligned pathways

2. Neutralizing any residual emissions at the Net-Zero target year and any GHG emissions released into the atmosphere thereafter.

The momentum towards Net-Zero is evident in the commitments made by countries, cities, businesses, and other institutions. More than 140 countries - have set a net-zero target, covering about 88% of global emissions. More than 9,000 companies, over 1000 cities, more than 1000 educational institutions, and over 600 financial institutions have joined the Race to Zero, pledging to take rigorous, immediate action to halve global emissions by 2030.[2]

In the face of this existential challenge, Net-Zero emerges as a pathway towards a sustainable future. The Conference of Parties (COP) 26 summit in Glasgow underscored the global consensus on the urgency of decarbonization, with Net-Zero becoming a central tenet in the collective commitment to securing a viable and resilient planet. The imperative

[1] https://www.ipcc.ch/assessment-report/ar6/

[2] Net Zero Coalition | United Nations

for Net-Zero is a call for pragmatic and transformative change, emphasizing the need to mitigate the impacts of climate change and chart a course towards a more sustainable, resilient, and equitable world. This necessitates a concerted global effort to accelerate the transition towards a Net-Zero future, ensuring a sustainable and habitable planet for future generations.

Science Based Target Initiative

The Science Based Targets initiative (SBTi) is a collaboration between the Carbon Disclosure Project (CDP), the United Nations Global Compact, World Resources Institute (WRI) and the Worldwide Fund for Nature (WWF).

Science-based targets show companies how much and how quickly businesses need to reduce their GHG emissions to prevent the worst impacts of climate change, leading them on a clear path towards decarbonization. By guiding companies in science-based target setting, SBTi enables them to tackle climate change while seizing the benefits and boosting their competitiveness in the transition to a net-zero economy.

The Science Based Targets initiative (SBTi):

- Defines and promotes best practices in emissions reductions and net-zero targets in line with climate science.
- Provides target setting methods and guidance to companies to set science-based targets in line with the latest climate science.
- Includes a team of experts to provide companies with independent assessment and validation of targets.

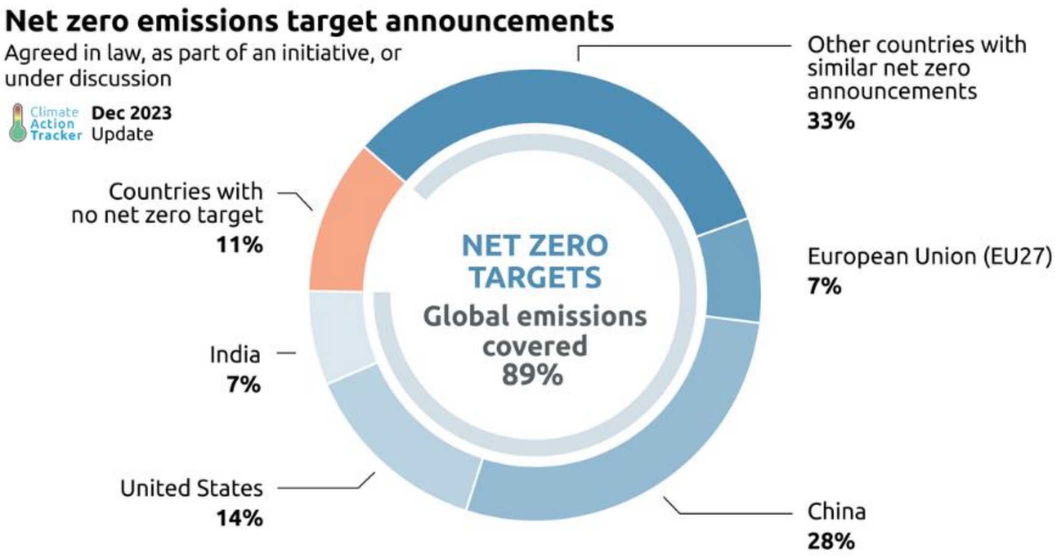
Over 4,000 companies worldwide are leading the transition to a net-zero economy by setting emissions reduction targets grounded in climate science through the SBTi. As of March 2023, over 2,300 companies have had science-based targets approved with the SBTi. The SBTi's 2021 Progress Report revealed that one third of global market capitalization has committed to climate action through the SBTi, and 1.5 billion tonnes of CO2 are covered by the SBTi (Scope 1 and 2). 2021 also saw 53 million tonnes of CO2 emissions reductions across all targets.[3]

2.2. Global scenario of Net Zero commitments

The global momentum towards achieving Net-Zero is rapidly intensifying, as evidenced by the active participation of more than 145 countries, including major players such as China, the United States, India, and the European Union. This concerted effort at the national level reflects a shared commitment to address the urgent challenges posed by climate change.[4]

[3] Science Based Targets initiative (SBTi) | World Resources Institute (wri.org)
[4] CAT net zero target evaluations | Climate Action Tracker

Figure 2 Net Zero global targets



Source: Climate action tracker

A study conducted by Oxford reveals that the current wave of Net-Zero pledges extends beyond national boundaries, covering over two-thirds of the global economy. This signifies a substantial integration of Net-Zero commitments into the fabric of the global economic landscape, demonstrating a widespread acknowledgment of the need for decisive action on a broad scale.

Notably, the race to Net-Zero is not confined to nations alone. Organizations, both large and small, are actively joining this global initiative. A prime example is the Science-Based Targets Initiative (SBTi), where over 4000 companies have pledged their commitment to Net-Zero targets as of 2023.[5] This corporate involvement emphasizes a growing awareness within the business sector regarding the importance of sustainability and the role they play in mitigating climate change.

The collaboration between countries and organizations in this Net-Zero race underscores a shared responsibility to curtail the impacts of global warming. The combined influence of these commitments from nations and companies is indicative of a concerted effort to transition towards a sustainable and Net-Zero future. As the race accelerates, it signifies a crucial turning point in the global fight against climate change, with stakeholders from various sectors actively contributing to the collective goal of achieving Net-Zero emissions.

2.3. India’s Net Zero commitment

India, as an emerging economy, faces the complex challenge of balancing economic development and poverty eradication with the imperative to address GHG emissions. It's noteworthy that while India's emissions are set to rise, they originate from a historically low base. Importantly, India's cumulative emissions from 1850 to 2019 constitute less than 4

[5] Companies taking action - Science Based Targets

percent of the world's total carbon dioxide emissions during the pre-industrial era, despite being home to 17 percent of the global population.[6] Consequently, India's historical responsibility for global warming has been minimal, and its current annual per capita emissions stand at only about one-third of the global average.

During the 26th session of the United Nations Framework Convention on Climate Change(UNFCCC) which is COP 26 in November 2021, India outlined its commitment to achieving net-zero emissions by 2070. This commitment aligns with the principles of equity, climate justice, and the concept of Common but Differentiated Responsibilities and Respective Capabilities, as outlined in Article 4 of the Paris Agreement. India's long-term low-carbon development strategy has been submitted to the UNFCCC, emphasizing the goal of reaching net-zero by 2070.

As articulated by India's Prime Minister at COP 26, the "Panchamrita" or five-fold strategy addresses the challenge of climate change with specific targets:

- Enhance non-fossil energy capacity to 500 GW by 2030.
- Meet 50% of energy requirements with renewable energy by 2030.
- Reduce projected carbon emissions by one billion tonnes by 2030.
- Decrease the carbon intensity of the economy by 45% by 2030.
- Achieve Net-Zero emissions by 2070.[7]

As per the updated NDC, India now stands committed to reduce Emissions Intensity of its GDP by 45 percent by 2030, from 2005 level and achieve about 50 percent cumulative electric power installed capacity from non-fossil fuel-based energy resources by 2030[8]. Moreover, India's long-term low-carbon development strategy pivots around seven key transitions:

- Low-carbon development of electricity systems consistent with overall development goals.
- Development of an integrated, efficient, and inclusive transport system.
- Promotion of adaptation in urban design, energy and material efficiency in buildings, and sustainable urbanization.
- Promotion of economy-wide decoupling of growth from emissions and the development of an efficient, innovative, low-emission industrial system.
- Development of carbon dioxide removal and related engineering solutions.
- Enhancing forest and vegetation cover in line with socioeconomic and ecological considerations.
- Addressing economic and financial needs associated with low-carbon development.

These transitions underscore India's commitment to a comprehensive and balanced approach, ensuring that its development path is environmentally sustainable and aligns with global climate objectives. The strategy emphasizes not only the reduction of emissions but

[6] Press Information Bureau (pib.gov.in)
[7] Press Information Bureau (pib.gov.in)
[8] pib.gov.in/PressReleaseIframePage.aspx?PRID=1847812

also the promotion of sustainable practices across various sectors critical to India's development trajectory.

2.4. Energy transition push in India

India has set a target to achieve Net Zero emissions by 2070 during COP26. The oil and gas industry have a significant influence over India's economy, being one of its eight core sectors. India aims to diversify its energy sources and reduce dependence on fossil fuels, including oil and gas, in pursuit of a more sustainable energy mix. Additionally, India is actively exploring the feasibility of green hydrogen as an alternative and cleaner fuel option.

Encouragement is given to India's oil and gas industry to adopt cleaner technologies, curbing carbon emissions. Enhancing the efficiency of oil refineries and employing advanced emission control methods can mitigate environmental effects. Oil and gas firms are expanding their portfolios by investing in clean technology initiatives and renewable energy ventures.

The Government of India is steadfast in its commitment to the Net-Zero goal and has implemented and is in the process of introducing several strategic initiatives to propel India's sustainable transformation. Notable among these initiatives are:

Introduction of Carbon Markets:

- Voluntary Carbon Market: The government is actively working on establishing a voluntary carbon market, set to be operationalized by Q4-2023. The Bureau of Energy Efficiency (BEE) will play a pivotal role as the nodal agency, creating a platform for voluntary carbon credit transactions.
- Mandatory Carbon Market: With an eye on harnessing India's potential as the largest exporter of Carbon credits globally, the government is shaping a mandatory carbon market, slated for introduction by 2025. This move aligns with the broader objective of utilizing carbon credits to meet India's internal Net-Zero targets.

Biofuels Program Under the Ministry of Petroleum and Natural Gas (MoPNG):

- Promoting Bioethanol (Pradhan Mantri JI-VAN Yojana): The government is actively driving the adoption of bioethanol through the Pradhan Mantri JI-VAN Yojana, a crucial initiative aimed at enhancing the use of sustainable biofuels.
- Promoting Compressed Biogas (SATAT Scheme): Emphasizing the importance of cleaner energy sources, the SATAT scheme encourages the production and utilization of compressed biogas, contributing to a more sustainable energy landscape.

Renewable Programs Under the Ministry of New and Renewable Energy (MNRE):

- Mega and Ultra Mega Solar Parks: The government is scaling up solar energy infrastructure through the development of Mega and Ultra Mega Solar Parks, fostering large-scale renewable energy generation.

- Grid Connected Solar Rooftop Program: Encouraging decentralized renewable energy production, the Grid Connected Solar Rooftop Program is a key initiative to harness solar energy at the local level.
- Promoting Renewable Energy Through Green Energy Open Access - Rules, 2022: The Green Energy Open Access rules of 2022 exemplify the government's commitment to facilitating and promoting the adoption of renewable energy sources.

These initiatives underscore the Indian government's proactive stance in driving a comprehensive and sustainable approach towards achieving Net-Zero, encompassing carbon market development, biofuel promotion, and an extensive renewable energy agenda. As India continues this trajectory, these strategic measures are poised to play a crucial role in shaping a greener and more sustainable future.

2.5. Implication of Net-Zero on oil & gas sector

The global Net-Zero target has far-reaching implications for the Oil & Gas sector, which currently accounts for 15% of the total energy-related emissions worldwide.[9] As nations strive to achieve net-zero carbon emissions, several key factors will shape the future of the industry:

- **Reduction in Demand:** The foremost implication of the global net-zero target is a significant reduction in the demand for oil and gas. As societies transition to cleaner energy sources, there will be a pronounced shift away from fossil fuels. To adapt and remain competitive, oil and gas companies must proactively diversify their portfolios by investing in renewable energy alternatives such as solar, wind, and hydrogen. This strategic pivot is essential for sustainability and long-term viability.
- **Regulatory Changes:** Governments worldwide are enacting stringent regulations to combat greenhouse gas (GHG) emissions. This involves imposing carbon pricing mechanisms and other compliance measures on industries, particularly on oil and gas companies. Adherence to these regulations will not only be mandatory but will also contribute to the sector's overall alignment with global sustainability goals.
- **Technological Investments:** To meet net-zero targets, oil and gas companies must invest heavily in innovative technologies that reduce emissions throughout their value chains. Carbon Capture Utilization and Storage (CCUS) technologies, along with advancements in energy-efficient processes, will play a crucial role. These technological investments are not only essential for meeting regulatory requirements but are also imperative for the industry's survival in a rapidly changing energy landscape.
- **Investment Pressure:** The growing concern among investors about climate-related risks is putting pressure on oil and gas companies. Investors are increasingly seeking transparency regarding emissions, climate risk assessments, and strategies for transitioning to net-zero. Companies that fail to address these concerns may face challenges in securing funding and could experience a decline in shareholder

[9] IEA Oil and Gas – Net Zero Transition

confidence. Therefore, oil and gas companies must prioritize transparent reporting and develop robust strategies for navigating the transition to cleaner energy.

In summary, the global Net-Zero target necessitates a fundamental transformation within the Oil & Gas sector. Companies must embrace sustainability, invest in renewable energy, adapt to regulatory changes, and adopt innovative technologies to remain resilient in a low-carbon future. The industry's ability to navigate these challenges will determine its role in the evolving global energy landscape.

3. Methodology for GHG Accounting for ONGC

3.1. Project Boundary

The scope of this report will focus solely on ONGC as a standalone company. Group companies such as HPCL, ONGC Videsh, MRPL, OMPL, OPaL, OTPC, among others, are not included in this report.

Organizational Boundary: The GHG emissions presented in this report have been consolidated using the operational control approach, whereby ONGC has reported 100% of emissions from its work centers.

Operational Boundary: The scope of the standalone entity covered in this report includes a total of 36 work centers, comprising 16 assets, 8 basins, 3 plants, and 12 institutions.

The following represent the operationally controlled facilities included in the consolidation of GHG inventory of ONGC:

Figure 3 Work centres in the GHG inventory of ONGC.

Offshore Assets	Onshore Assets	Basins	Plants	Institutes
Mumbai High Asset	Ankleshwar Asset	AAFB Exploratory Asset Silchar Basin	Hazira Plant	ONGC Academy, Dehradun
Bassein & Satellite Asset	Mehsana Asset	Jodhpur Exploratory Asset	Uran Plant	CEWELL
Neelam & Heera Asset	Assam Asset	Assam & Assam Arakan Basin	Dahej Plant	IPSHEM, Goa
Eastern Offshore Asset	Rajahmundry Asset	Cauvery Basin		IEOT, Mumbai
	Jorhat Asset	Krishna Godavari Basin		IOGPT, Mumbai
	Ahmedabad Asset	MBA/MBP Basin		INBIGS, Assam
	Cauvery Asset	Western Offshore & Onshore Basin		GHRTC
	Cambay Asset	Frontier Basin		IRS, Ahmedabad
	Tripura Asset			RTI Chennai
	CBM Bokaro Asset			GEOPIC
	CFB Asset			IDT
	MBA Asset			KDMIPE

3.2. GHG Assessment methodology

GHG emissions have been calculated using emission factors and Global Warming Potential (GWP) factors taken from IPCC's Sixth Assessment report. The emissions calculation methodology has been prescribed by the GHG Protocol which is based on SBTi. It classifies emissions into three core categories:

- Scope 1 accounts for direct emissions stemming from sources under the organization's ownership or control, like on-site fossil fuel combustion.
- Scope 2 encompasses indirect emissions linked to the organization's consumption of purchased electricity, heat, or steam.
- Scope 3 encompasses all remaining indirect emissions, including those originating from supply chains, employee commuting, and business-related travel.

The table presented below furnishes data on activity, emission factor, and methodological specifics (in detail explanation mention in Annexure 9.6):

Figure 4 Emission Factor for different sources of fuel

Emission Type	Methodology Details
Direct Emissions (Scope-1)	Consumed volumes of fuel were converted into TJ by using heating value and multiplied by the published emission factors in the IPCC's Sixth Assessment Report and global warming potential
Indirect Emissions (Scope-2)	Purchased electricity in Million kWh multiplied by emissions factor.
Scope 3	Category 1 - Purchased goods and services. Category 2 - Capital goods Category 3 - Fuel- and energy-related activities Category 4 - Upstream transportation and distribution Category 6 - Business travel Category 7 - Employee commute Category 9 - Downstream transportation and distribution Category 10 - Processing of sold products. Category 11 - Use of sold products

3.3. Emission profile: Assumptions and projections

A regression model has been applied to project oil output, encompassing both crude oil and natural gas, until fiscal year 2038. The forecast leverages production data from fiscal years 2022,2023,2024,2025,2026 and 2040 utilizing insights derived from historical trends to predict future outcomes.

In 2022, the Integrated Report for that fiscal year documented an oil output of 40.45 units, serving as a baseline for subsequent projections. The model considers various factors influencing production dynamics, providing a comprehensive view of potential future scenarios. The subsequent years reveal a mix of fluctuations and upward trends, with outputs of 44.79 units in 2024, as per Corporate Planning, and a projection of 70.00 units in 2040 according to the ONGC Energy Strategy.

In tandem with production forecasting, the analysis extends its scope to incorporate greenhouse gas (GHG) intensity and the projected growth of production. This broader perspective allows for the forecast of future emissions associated with the anticipated production levels.

Table 4 Primary Data for Oil Output projections

FY	Oil Output: Crude oil + Natural Gas	Source
2022 (Baseline)	40.45	Integrated Report FY 2022
2023	40.21	Integrated Report FY 2023
2024	44.79	Corporate Planning
2025	43.82	
2026	44.18	
2040	70.00	ONGC Energy Strategy 2040

Figure 5 Regression model based on primary data

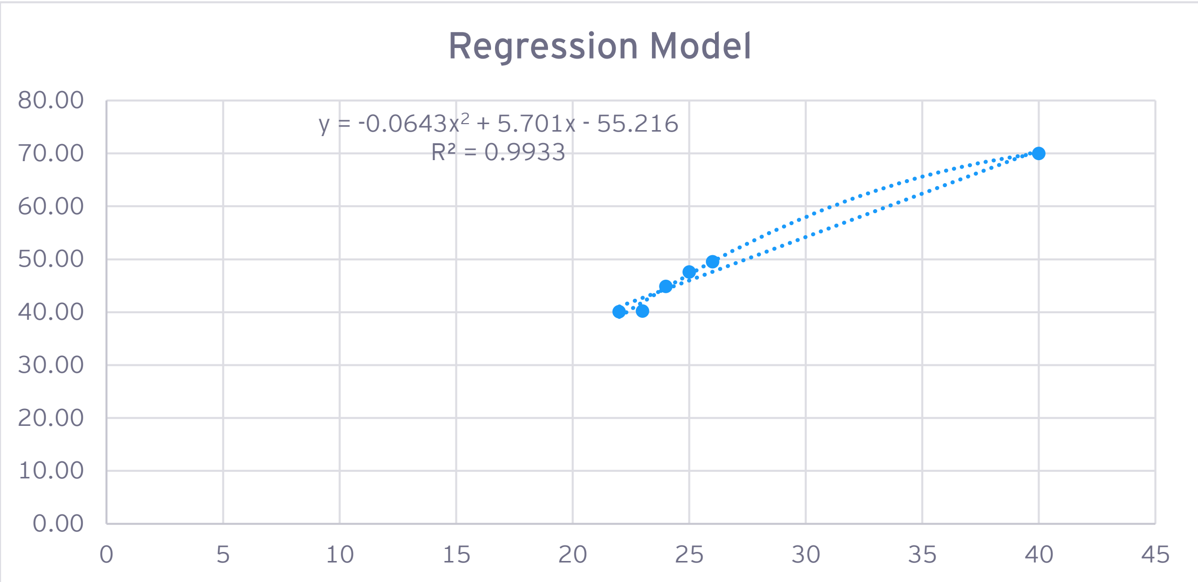
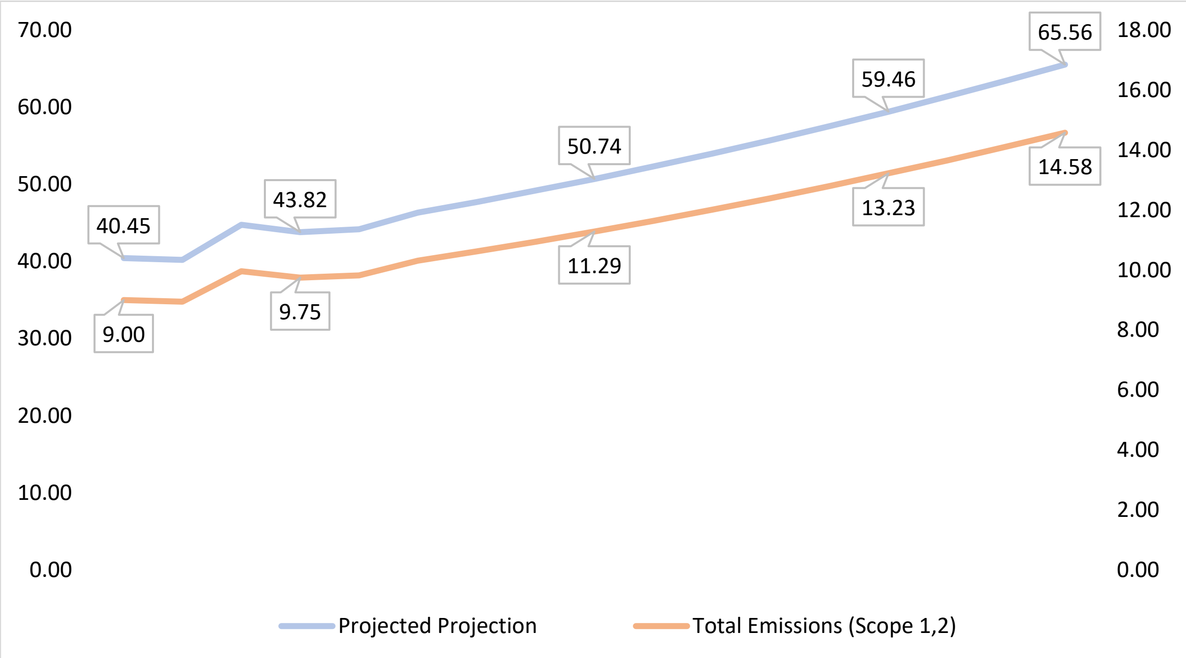


Figure 6 Projected production and GHG emissions till FY 2038



According to the regression model analysis, ONGC's projection profile, measured in million metric tons of oil equivalent (MMTOE), exhibits a steady increase over the forecasted years, starting at 40.45 MMTOE in FY 22 and reaching 65.56 MMTOE by FY 38. Concurrently, the GHG scope 1 and 2 emissions, also display an upward trend. Starting at 9 million tCO_2e in FY 22, which mayclimb to 14.58 million tCO_2e by FY 38 in Business as Usual (BAU) case. This data underscores ONGC's expanding energy production and its associated environmental impact.

3.4. Baseline emissions of ONGC

ONGC's decarbonization target for operational (Scope 1 and Scope 2) emissions have been established with the **base year as FY22.** When evaluating the significance and materiality of ONGC's emissions, several critical factors come into play. These factors encompass the volume of emissions, ONGC's level of influence over the emission source, the accessibility of emission data, and the dependability of estimation methods.

GHG baseline emissions for ONGC (FY 21-22)

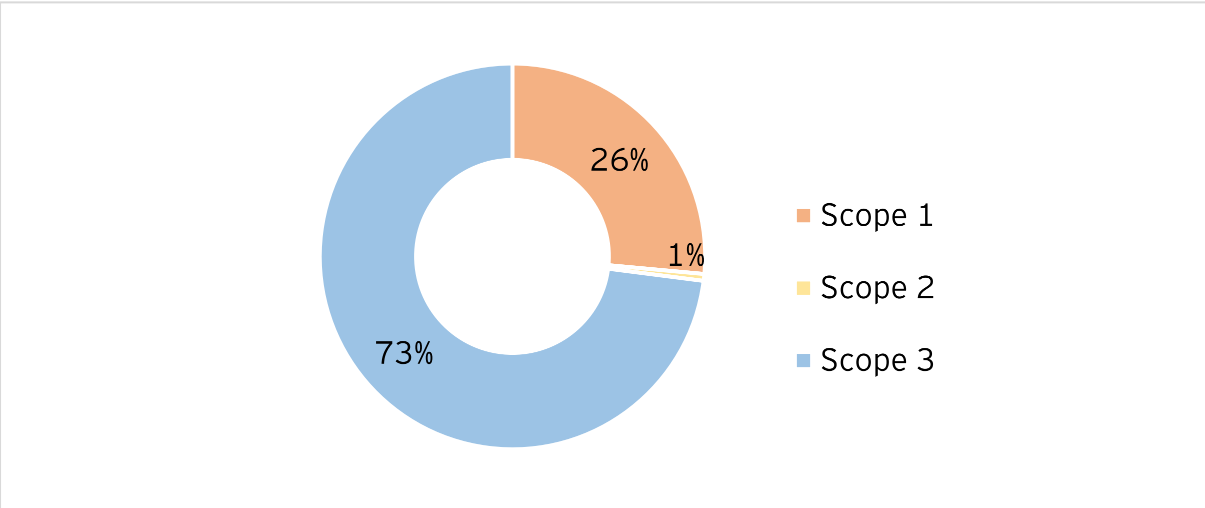
ONGC has adopted the Absolute Contraction Approach established by SBTi for establishing its scope 1 and scope 2 reduction targets. Accordingly, baseline emissions for the FY 21-22 have been calculated as follows:

Table 5 GHG Baseline Emissions

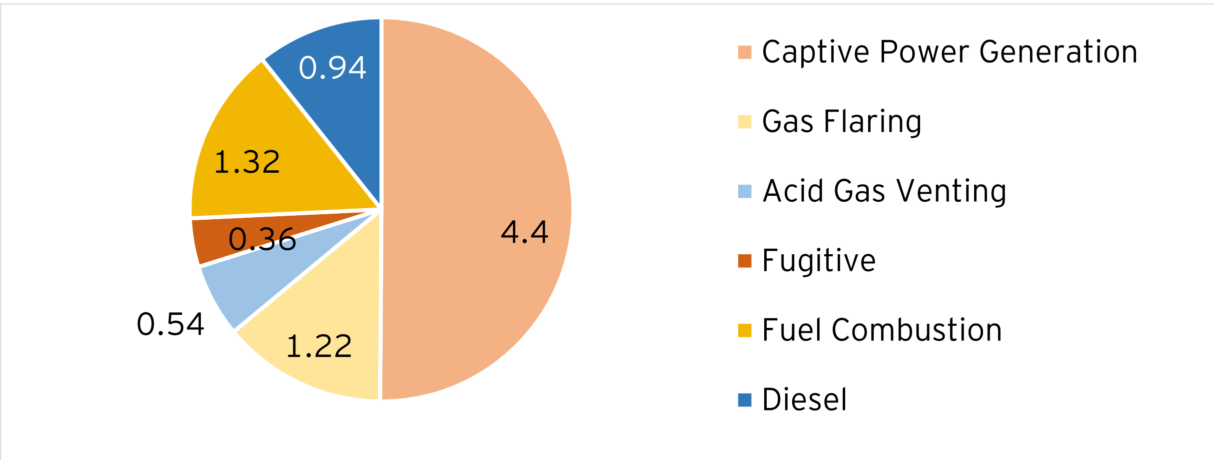
S No.	Particulars (Baseline FY 21-22)	(Million tCO_2e)
1	Scope 1 emissions	8.81
2	Scope 2 emissions	0.19
3	**Total Emissions (Scope 1 + 2)**	**9.00**
4	Scope 3 emissions	24.30
5	**Grand Total (Scope 1 + 2 + 3)**	**33.3**

S No.	Emission Sources (Scope 1)	(Million tCO2e)	%
1	Captive Power Generation	4.40	49%
2	Gas Flaring	1.22	14%
3	Fuel Combustion- Heating and CHP	1.32	15%
4	Diesel	0.94	10%
5	Acid Gas Venting	0.54	6%
6	Fugitive	0.36	4%
7	ATF	0.02	0%
	Emission Sources (Scope 2)		
8	Grid Electricity Purchase	0.19	2%
	Total	9.00	100 %

GHG Emissions for FY 21-22



Scope 1 Emissions by source



In terms of Scope 1 emissions, ONGC contributes a total of 8.81 million tonnes of carbon dioxide equivalent (tCO2e), with the major sources being captive power generation (49%), gas flaring (14%), and fugitive emissions (4%). On the other hand, Scope 2 emissions, totalling 0.19 million tCO2e, mainly stem from grid electricity purchases, highlighting ONGC's acknowledgment of indirect emissions associated with its energy consumption. The detailed categorization of emissions sources, such as fuel combustion, diesel, and aviation turbine fuel (ATF), offers stakeholders a nuanced understanding of ONGC's environmental footprint.

Scope 3 Emissions Categories	Emissions
Category 1 - Purchased goods and services	1.90
Category 2 - Capital goods	0.09
Category 3 - Fuel- and energy-related activities	0.05
Category 4 - Upstream transportation and distribution	0.04
Category 6 - Business travel	0.01
Category 7 - Employee commute	0.02
Category 9 - Downstream transportation and distribution	1.55
Category 10 - Processing of sold products	17.06
Category 11 - Use of sold products	3.53
Category 5,12,13,14,15	Not Significant

3.5. Operation wise GHG Emissions for FY 21-22

GHG baseline emissions for ONGC (Operations, FY 22-22)

Table 6 GHG Emissions in ONGC operations

Scope 1 Emissions		
Classification	**Million tCO_2e**	**% Contribution**
Assets (Offshore)	4.77	54.14
Assets (Onshore)	1.21	13.73
Plants	1.04	11.80
Others (Services, basins, institutes)	1.79	20.31
Total	8.81	
Scope 2 Emissions		
Classification	**Million tCO_2e**	**% Contribution**
Assets (Offshore)	0.01	5.26
Assets (Onshore)	0.12	63.15
Plants	0.01	5.26
Others (Services, basins, institutes)	0.05	26.31
Total	0.19	

Scope 1 emissions which are the direct emissions, emanate from various business operations: with contributions from plants, onshore and offshore assets, basins, institutes, and services. Offshore assets account for the largest share, releasing 4.77 Million tCO_2e, while onshore assets contribute 1.2 Million tCO_2e and plants release 1.04 Million tCO_2e. The impact of basins, institutes and services is comparatively minor, together at 1.79 million tCO_2e.

The source of Scope 2 emissions (Indirect emissions) is grid electricity. Onshore and offshore assets, plants, basins, and institutes collectively contribute 0.19 million tCO_2e. Notably, onshore and offshore assets are responsible for the majority of these emissions, releasing 0.12 Million tCO_2e and 0.01 Million tCO_2e, respectively. The remaining contributions are from plants, services, basins, and institutes, totalling 0.01 million tCO_2e, and 0.05 million tCO_2e.

Figure 7 Operation wise GHG Emissions

Offshore Assets		Onshore Assets	
Scope 1	4.77	Scope 1	1.21
Scope 2	0.01	Scope 2	0.12
Scope 1+ 2	4.78	Scope 1 + 2	1.33
Mumbai High Asset	2.81	Ankleshwar	0.49
Bassein & Satellite	1.28	Mehsana	0.26
Neelam & Heera	0.51	Assam	0.25
Eastern offshore Asset	0.17	Rajahmundry Asset	0.14
		Jorhat Asset	0.18
		Ahmedabad Asset	0.17
		Cauvery Asset	0.06
		Cambay Asset	0.01
		Tripura Asset	0.009
		CBM Bokaro Asset	0.004

Basins		Plants		Institutes	
Scope 1	Negligible	Scope 1	1.04	Scope 1	Negligible
Scope 2	0.009	Scope 2	0.01	Scope 2	0.02150
Scope 1 + 2	0.009	Scope 1 + 2	1.05	Scope 1 + 2	0.02150
Western offshore &Onshore	0.0041	Hazira plant	0.55	GEOPIC+IDT+KDM	
Cauvery Basin	0.0037			IPE+ONGC Academy	
AAFB Exploratory silchar	0.0007	Uran plant	0.44	Dehradun	0.0200
Jodhpur Exploratory	0.0004			CEWELL	0.0013
Assam &Assam		Dahej Plant	0.06	IPEOT	0.0005
Arakan basin	0.0003			IPSHEM Goa	0.0002
MBA Basin	0.00002				
			0.4		

Services	
Scope 1	1.79
Scope 2	0.02
Scope 1 + 2	1.81
Services(Driling, Logging,	0.47
Corporate Services	0.40
Others	0.94

The greenhouse gas (GHG) emissions data from ONGC provides a detailed look at its environmental impact across work centres. Offshore activities, especially from Mumbai High Asset (2.81 Million tCO2e), Bassein & Satellite Asset (1.28 Million tCO2e), and Neelam & Heera Asset (0.51 Million tCO2e), contribute significantly to Scope 1 emissions. Onshore, Ankleshwar Asset leads with 0.4 Million tCO2e, followed by Mehsana Asset (0.26 Million tCO2e), Assam Asset (0.2 Million tCO2e), and Rajahmundry Asset (0.14 Million tCO2e).

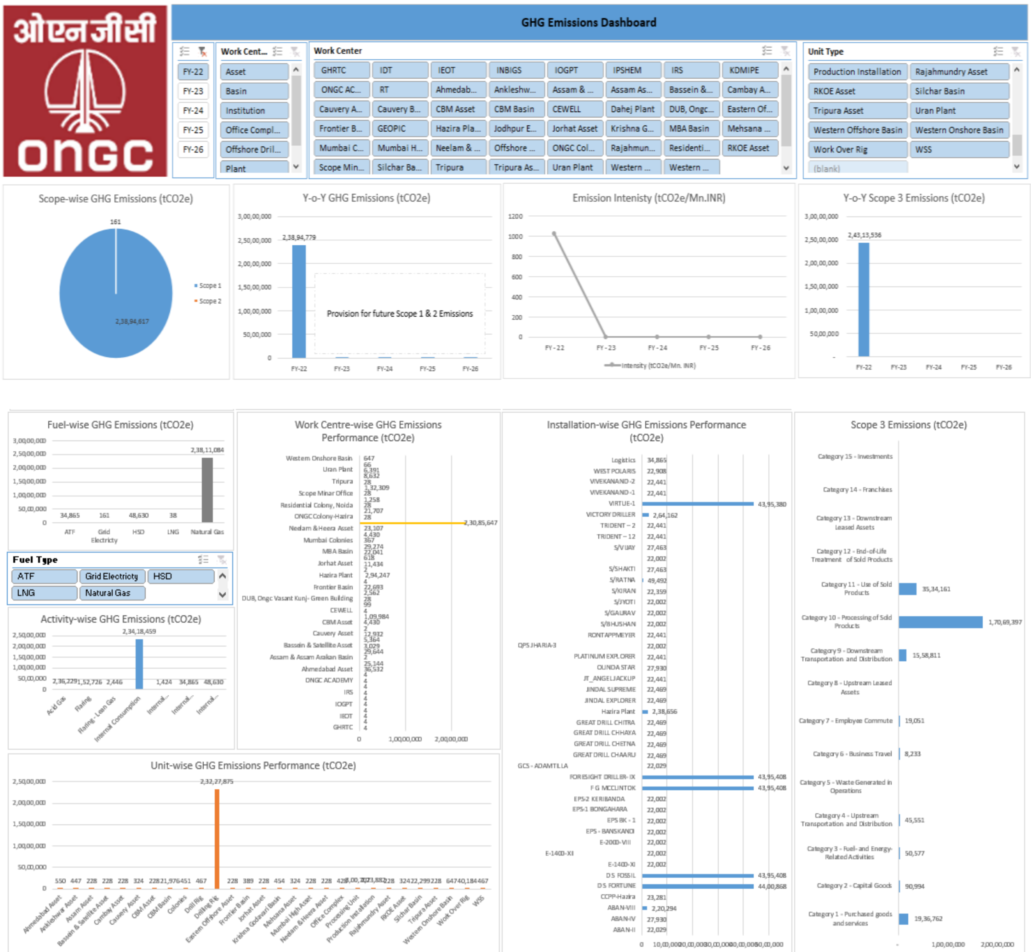
In specific basins, emissions are generally low, with Western Offshore and Onshore Basin , contributing 0.0004 Million tCO2e, Cauvery Basin contributing 0.0037 and AAFB Exploratory Asset Silchar Basin contributing 0.0007 Million tCO2e. Plants play a role, with Hazira Plant emitting 0.55 Million tCO2e, Uran Plant contributing 0.44 Million tCO2e, and Dahej Plant releasing 0.06 units.

Institutes and services also have minimal emissions. Institutes at Dehradun GEOPIC+IDT+KDMIPE+ONGC Academy emits 0.02 Million tCO2e, and CEWELL contributes 0.0013 Million tCO2e. This detailed breakdown allows ONGC to identify areas for targeted emission reduction efforts, showcasing the company's commitment to transparent reporting and a sustainable operational approach.

3.6. GHG Dashboard (extract from Excel based Model)

The GHG inventory dashboard serves as a tool for ONGC to conveniently monitor and assess its greenhouse gas emissions data in an interactive and user-friendly manner. The development of this dashboard involves a series of steps, commencing with the creation of a GHG data management template that captures all essential data for calculating emissions. Subsequently, workstations input their data into these sheets based on their respective operations. A thorough review of these data sheets for completeness and accuracy is conducted before they are consolidated into a shared OneDrive folder. A master sheet is then generated, aggregating all data from various workstations, and calculating the overall GHG emissions. Sustainability Manager regularly update their input sheets to ensure data accuracy. Ultimately, the result is an interactive and dependable GHG Emission dashboard. This resource empowers the Sustainability Manager to analyse emission trends, pinpoint areas in need of improvement, monitor progress towards achieving emission reduction targets, and formulate strategies and initiatives geared toward reducing the organization's carbon footprint.

Figure 8 Snapshot of GHG Dashboard



4. Decarbonization Levers for ONGC Operational Emissions (Scope 1 and 2)

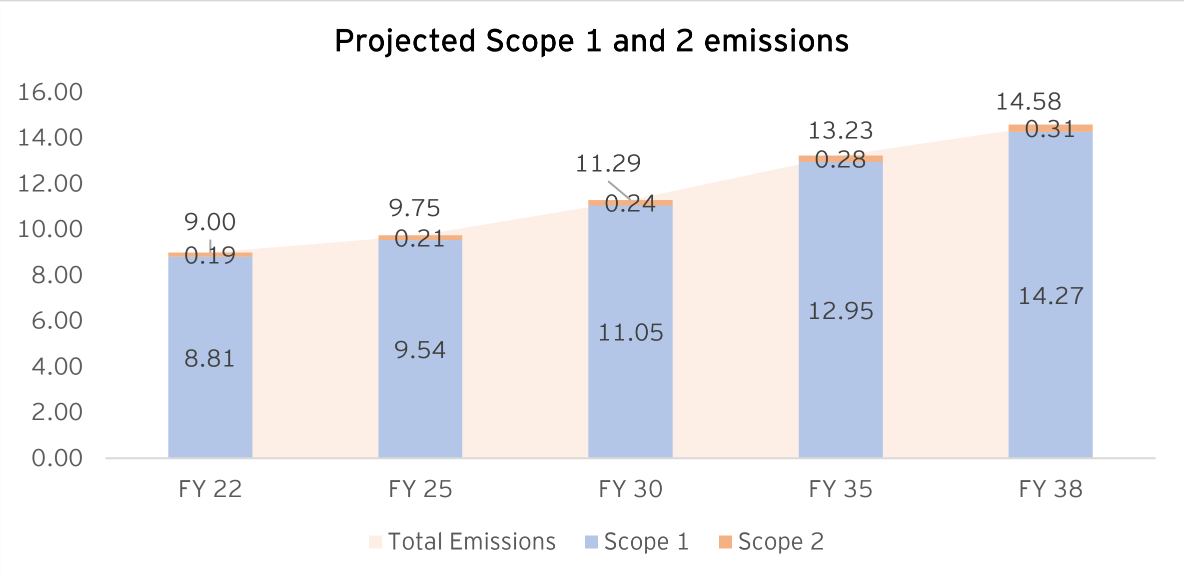
4.1. Projected GHG emissions

The regression model employed for projecting oil output, covering both crude oil and natural gas, extends its forecast horizon until fiscal year 2038. Drawing from production data spanning fiscal years 2022 to 2026 and 2040, the model utilizes historical trends to anticipate future outcomes.

Establishing a baseline of 40.45 units in 2022, as documented in the Integrated Report for that fiscal year, subsequent projections reveal a blend of fluctuations and upward trajectories. Notably, Corporate Planning reports an output of 44.79 units in 2024, signaling a rise in production. Looking ahead, the ONGC Energy Strategy foresees a substantial increase, with production projected to reach 70.00 units by 2040.

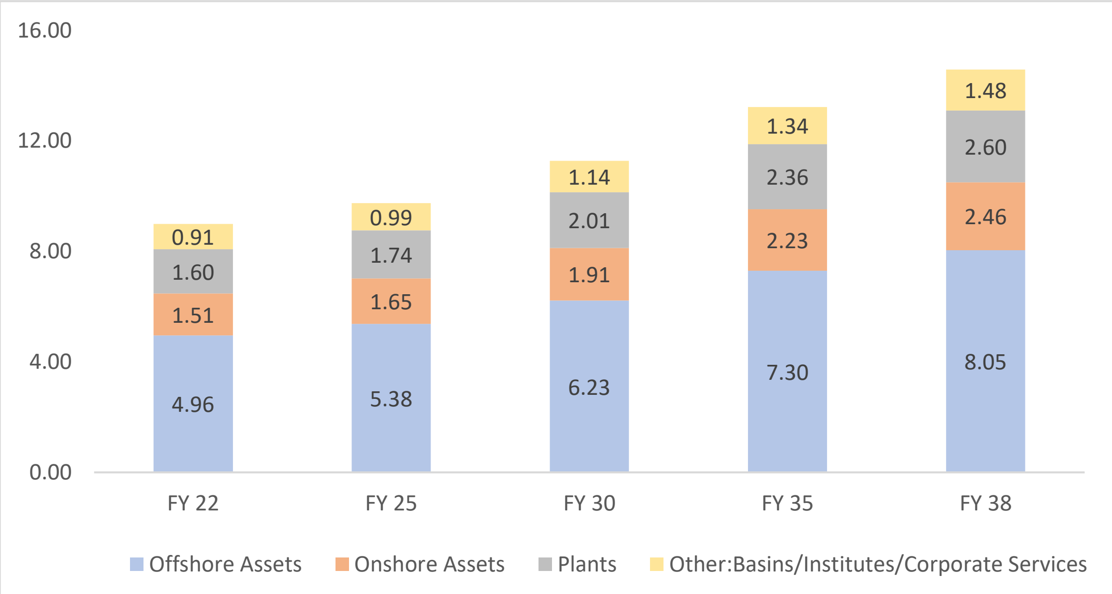
Furthermore, the analysis extends beyond production forecasting to encompass greenhouse gas (GHG) intensity and the anticipated growth in production. This broader perspective facilitates the estimation of future emissions associated with the envisaged production levels.

Figure 9 Projected Scope 1 and 2 emissions.



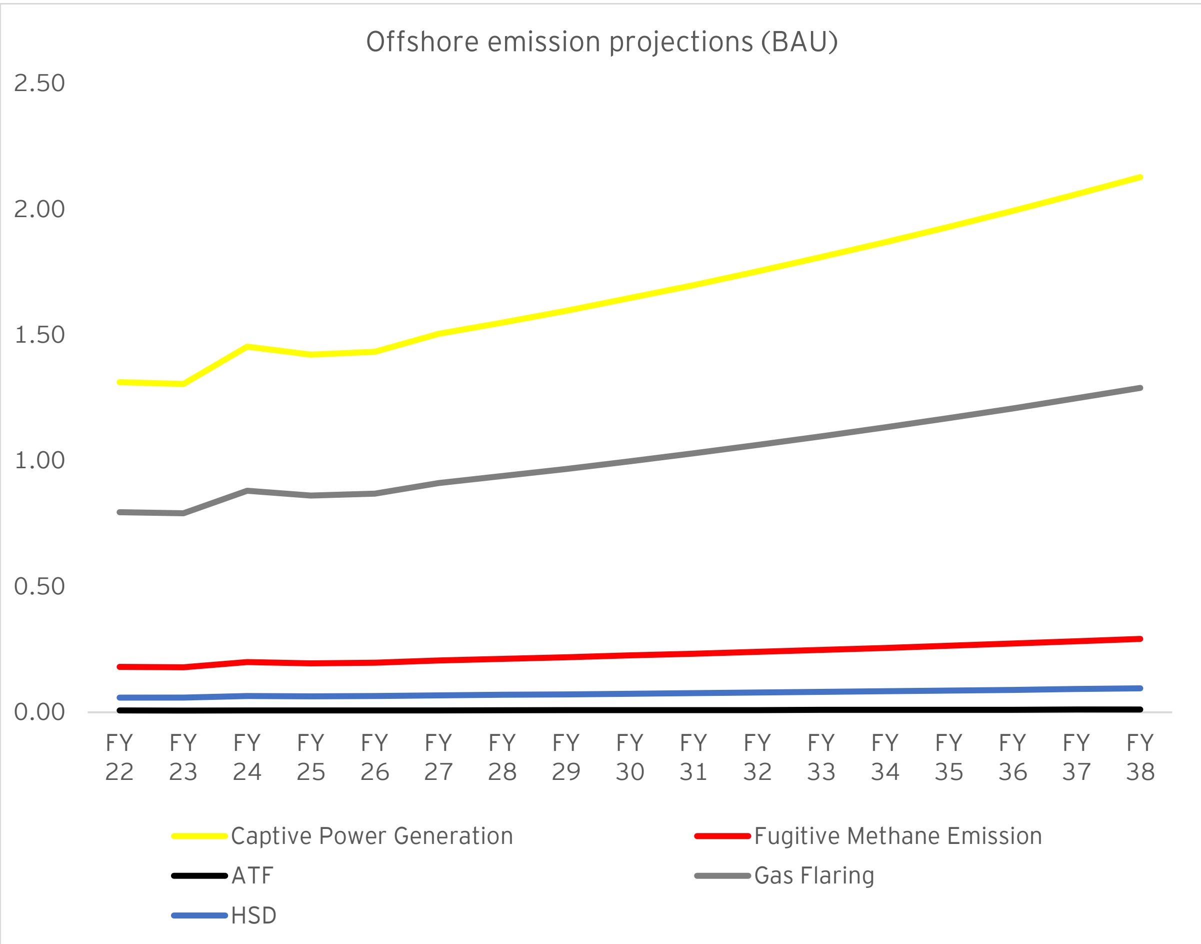
Based on data from the GHG Inventorization conducted in FY 22, asset wise emissions have been projected. The asset wise emissions projection narrowed down emission hotspots which were utilized to identify the most efficient ways to curb Scope 1 and 2 emissions by 2038.

Figure 10 Operation wise emission projections



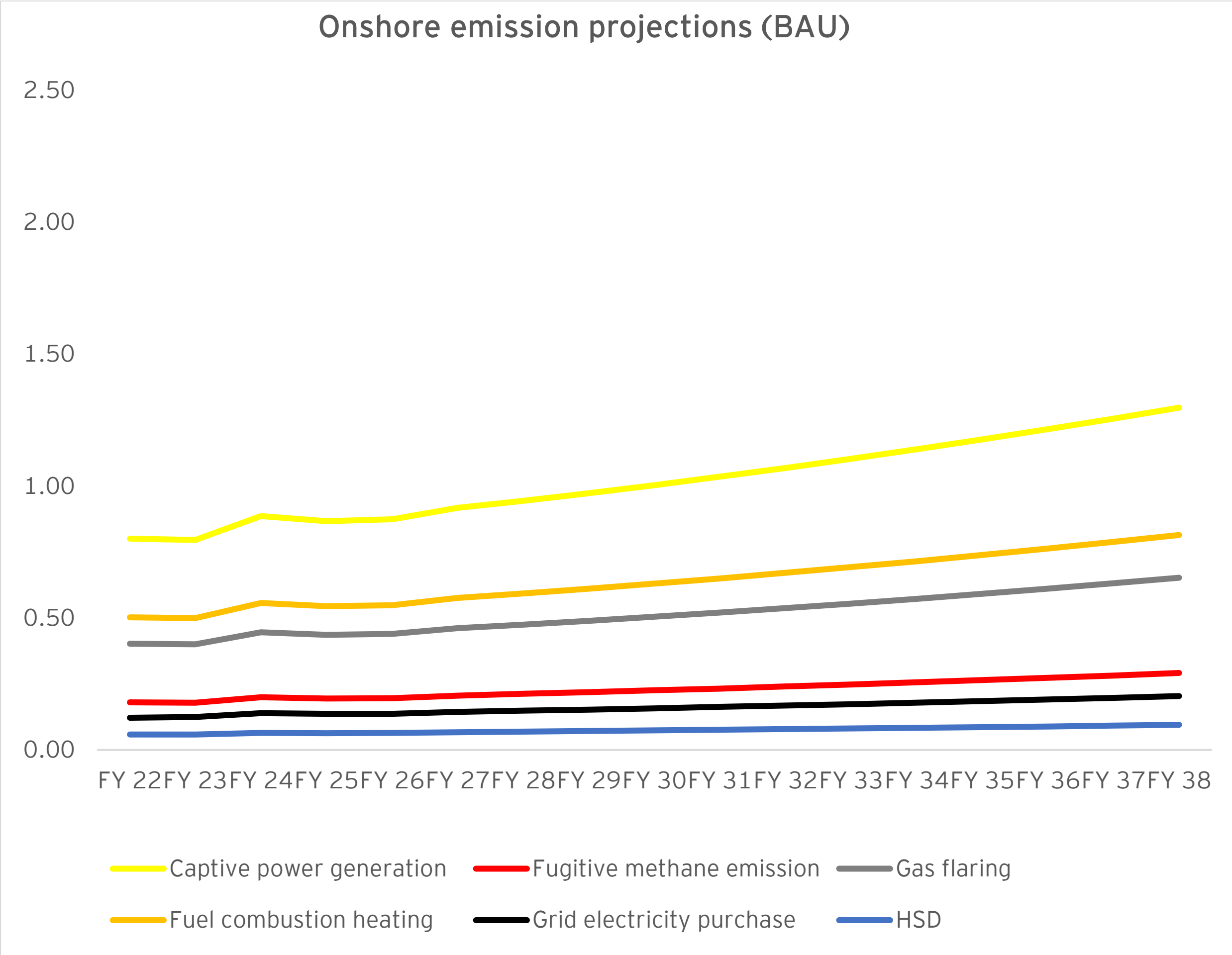
The levers recommended in this report have been determined by identifying the most efficient levers for different hotspots. The report also considered the initiatives undertaken by ONGC's peers and analyzed the feasibility of the levers for ONGC's various assets.

Figure 11 Offshore assets emission projections



Projected emissions across various categories showcase a noticeable trend. Captive Power Generation, a significant contributor, is expected to incrementally rise from 1.31 million tCO2e in FY 22 to 2.25 million tCO2e in FY 38, reflecting an upward trajectory. Fugitive Methane Emission, another noteworthy factor, follows a gradual increase from 0.18 million tCO2e in FY 22 to 0.31 million tCO2e in FY 38. Fuel-related emissions, represented by ATF and Diesel, remain relatively stable over the forecast period, with minimal fluctuations. Gas Flaring, however, demonstrates a notable ascent, escalating from 0.80 million tCO2e in FY 22 to 1.36 million tCO2e in FY 38.

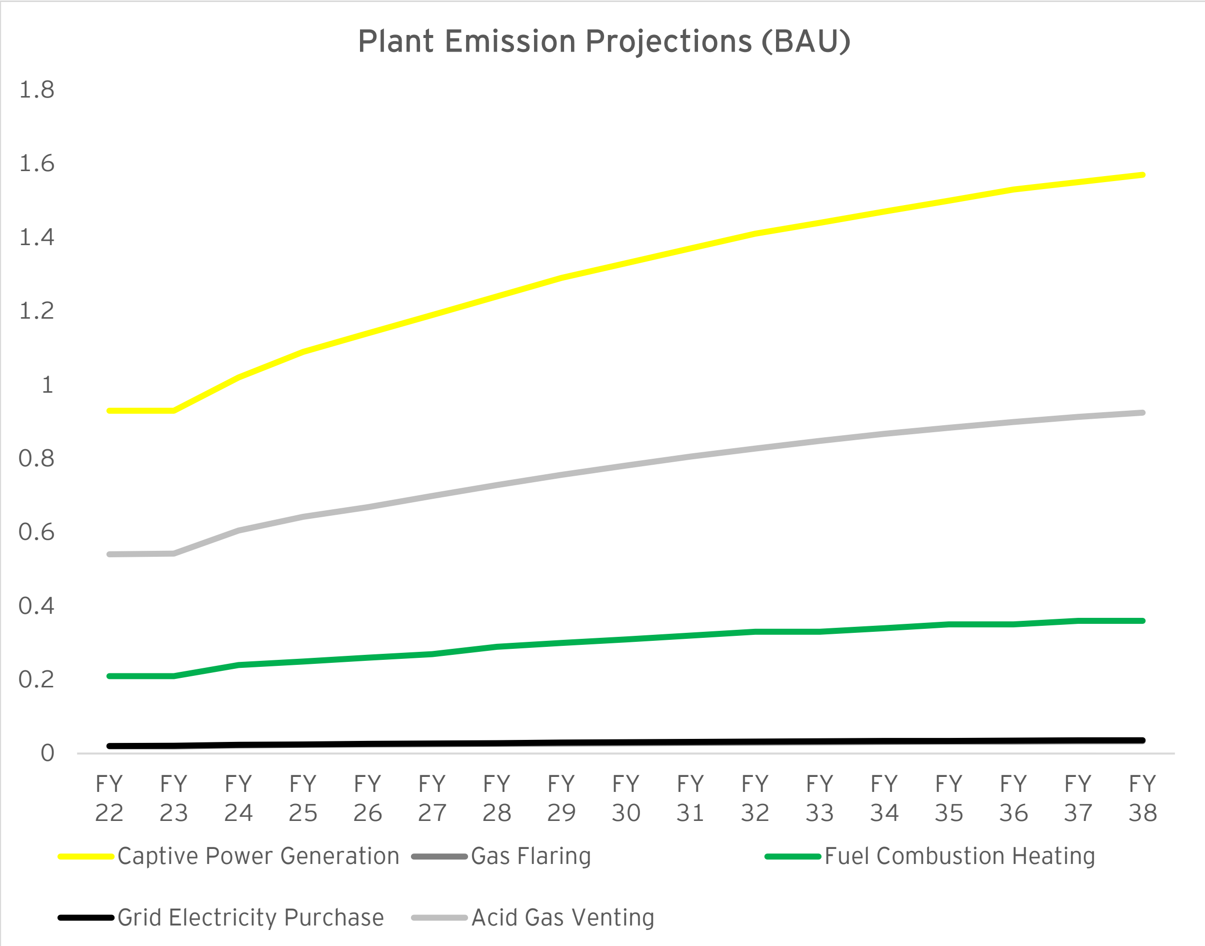
Figure 12 Onshore assets emission projection



Captive Power Generation, a notable contributor, is expected to witness a gradual increase from 0.37 million tCO2e in FY 22 to 0.63 million tCO2e in FY 38. Fugitive Methane Emission, another key factor, displays a similar trend, rising from 0.18 million tCO2e in FY 22 to 0.31 million tCO2e in FY 38. Gas Flaring exhibits an upward trajectory as well, with projections ascending from 0.33 million tCO2e in FY 22 to 0.57 million tCO2e in FY 38.

Fuel combustion heating is projected to increase from 0.32 million tCO2e in FY 22 to 0.54 million tCO2e in FY 38, while Grid Electricity Purchase is expected to show a gradual rise from 0.12 million tCO2e in FY 22 to 0.22 million tCO2e in FY 38. Diesel emissions remain consistent over the forecast period, maintaining at 0.01 million tCO2e.

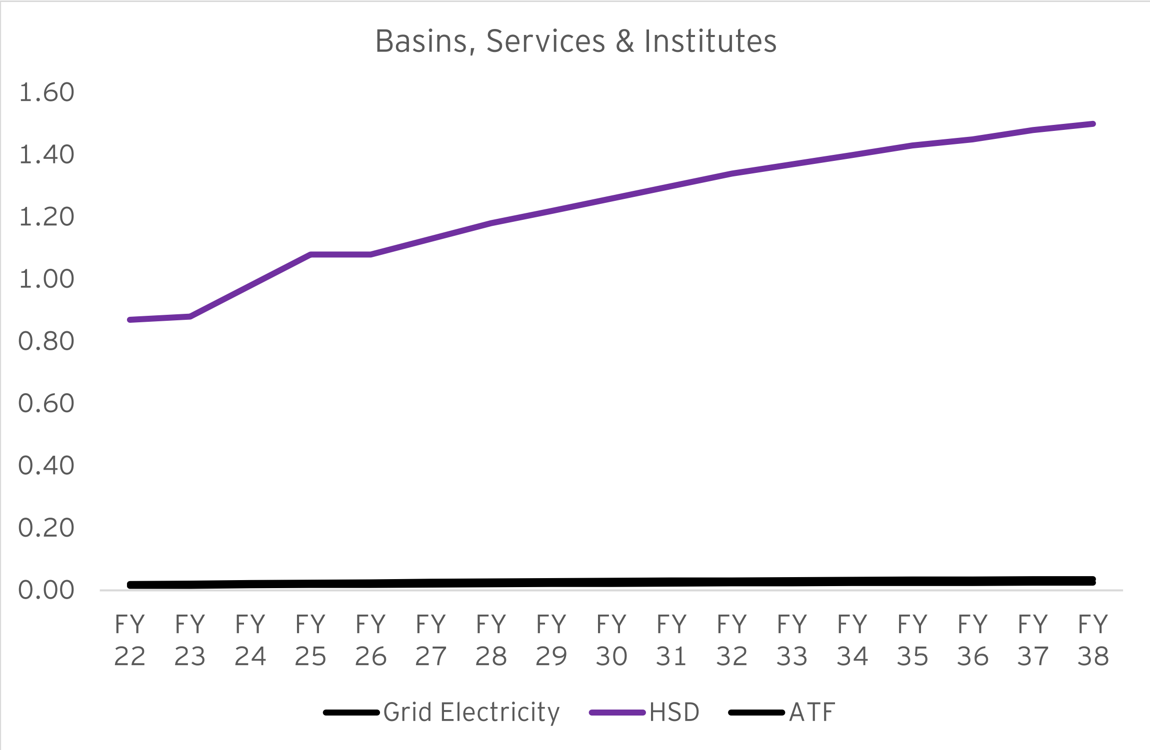
Figure 13 Emission projection for plants



Captive Power Generation is expected to experience a steady increase from 0.93 million tCO2e in FY 22 to 1.57 million tCO2e in FY 38, highlighting a gradual growth in emissions. Gas Flaring and Grid Electricity Purchase, while relatively minimal, are anticipated to remain consistent over the forecast period, maintaining at 0.03 and 0.04 million tCO2e, respectively.

Fuel Combustion Heating is set to rise gradually from 0.21 million tCO2e in FY 22 to 0.36 million tCO2e in FY 38, indicating a modest increase in emissions associated with this category. Acid Gas Venting, a notable contributor, is projected to climb from 0.54 million tCO2e in FY 22 to 0.92 million tCO2e in FY 38, showcasing a significant upward trend.

Figure 14 Emission projection for basins, services and institutes



Grid Electricity consumption is expected to see a gradual increase, starting at 0.02 million tCO2e in FY 22 and reaching 0.04 million tCO2e in FY 38, reflecting a growing demand for electricity within these operations.

High-Speed Diesel (HSD) consumption exhibits a discernible upward trajectory, rising from 0.87 million tCO2e in FY 22 to 1.50 million tCO2e in FY 38. This significant increase emphasizes the importance of fuel in supporting ONGC's operational activities. Aviation Turbine Fuel (ATF) consumption remains relatively stable throughout the forecast period, maintaining at 0.02 million tCO2e

4.2. Analysis of different Decarbonization levers

Offshore assets

As per a detailed profile analysis, ONGC's offshore assets account for 4.77 million tCO2e emissions. Natural gas (NG) consumption is responsible for approximately 64% of ONGC's Scope 1 emissions and is used in captive power generation, gas turbines, gas engines, and heating furnaces.

Table 7 Potential levers for emissions from offshore assets

Application	Potential Levers
Power Generation	• Electrification: Offshore wind • Hydrogen Fuel Cell (backup power)
Gas Flaring	• Zero Routine Flaring
NG for Compressor	• Electrification (Electric motors) • Hydrogen blending
Process gas	• Electrification • Fuel Switch • Energy efficiency
Fugitive Emissions	• Global Methane Initiative

Onshore assets

Natural Gas produced from onshore assets consists of power generation & gas engines, gas flaring, fugitive emissions and GDU fuel and heater.

Table 8 Potential levers for onshore asset emissions

Application	Potential Levers
Power Generation & Gas Engines	• Low Carbon Energy: Nuclear Energy, Renewable Energy, Bioenergy • Fuel Switch: Hydrogen • New Equipment: Hydrogen Turbine (SMR+CCS), CCU, Grid Electrification
Gas Flaring	• Zero Routine Flaring by 2030
Fugitive Emissions	• Global Methane Initiative
GDU Fuel, Heater	• Fuel Switch: Hydrogen • New Equipment: Hydrogen-powered boiler/furnace, CCU, • Electrification, Biomass + CCU

Processing Plants (On land)

Emissions from natural gas produced from plants can be attributed to power generation, purge gas/tech flaring, acid gas and FG for boiler/furnace.

Table 9 Potential levers for processing plants

Application	Potential Levers
Power Generation	• Fuel Switch: CBG/Hydrogen • New Equipment: Hydrogen Turbine (SMR+CCS) • Electrification • Low Carbon Energy: Nuclear Energy, Renewable Energy, Bioenergy + CCS
Purge gas/ tech flaring	• Switch burner fuel to CBG/Hydrogen • Recycle flare gas, FRSG
Acid gas	• Carbon Capture & Utilization
FG for boiler/furnace	• Fuel Switch: CBG/Hydrogen • New Equipment: Hydrogen-powered boiler/furnace, CCU • Electrification • Biomass + CCU

Work Centres: Plants, Assets, Institutes, Services, Corporate Services

Emission sources from the company's work centres include grid electricity, ATF and HSD.

Table 10 Potential levers for work centres' emissions

Source of Emission	Potential Levers
HSD- Diesel engines, DG Sets, Company-owned vehicles	• Switch to Biofuels • Energy Storage Systems • Biodiesel Genset • Fuel Cells • Scrubber Systems (capture at source), • Electric Vehicles
Grid Electricity - Motors as Prime movers, Lightings and Other	• Energy Efficiency • Switch to Renewable Energy (Captive/Open Access/Green Premium) + BESS
ATF – ATF for logistics	• SAF

5. Decarbonisation Roadmap

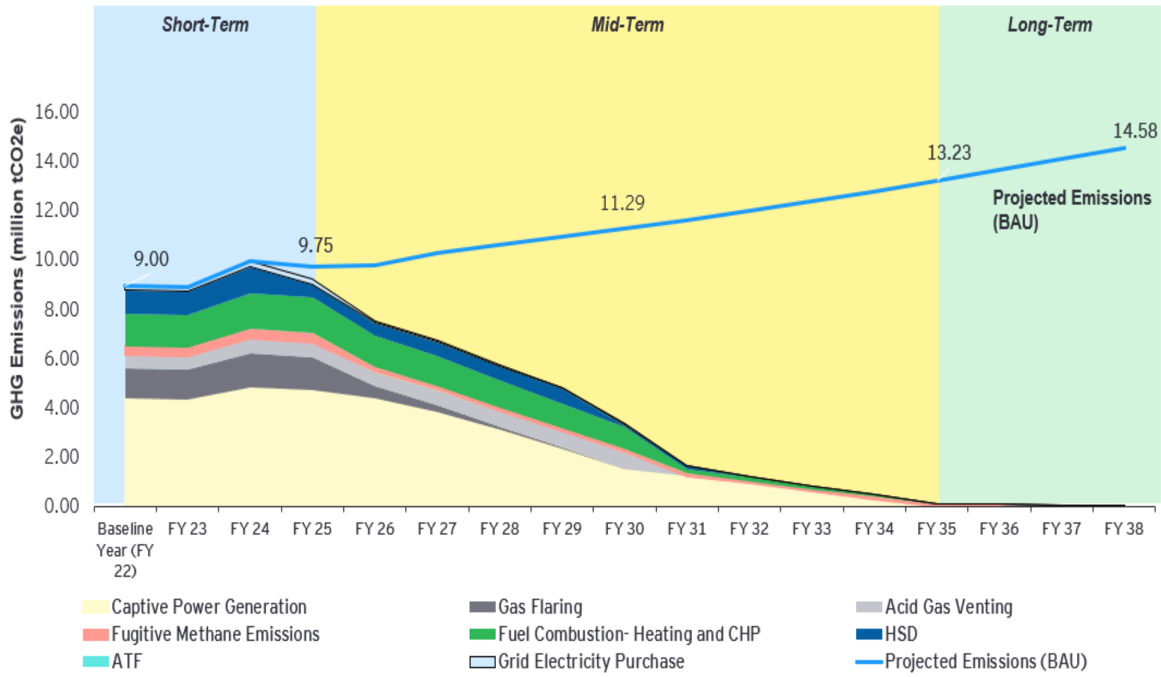
The decarbonization roadmap represents a strategic initiative aimed at achieving a milestone of zero operational (Scope 1 and Scope 2) emissions by the Fiscal year 2038. The roadmap has been developed, considering the projected Scope 1 and Scope 2 emissions for ONGC until FY 38. This approach aligns with global efforts to combat climate change and positions ONGC as a responsible and sustainable player in the energy sector.

As per the GHG inventorization, Category 9,10 and 11 contributes to 91.29 % of the total Scope 3 emissions, which is coming from downstream processing/use of the sold products. These Scope-3 emissions of ONGC are Scope 1 emission of downstream companies.

Since Indian Oil & Gas downstream companies have set their Net Zero Target between 2040-2050 e.g GAIL(2040), IndianOil(2046); this will help ONGC to achieve its Scope-3 reduction targets.

In order to navigate the landscape of emissions reduction, the roadmap incorporates a series of decarbonization levers strategically spread across short, medium, and long-term horizons. These levers are designed to address various aspects of ONGC's operations, ensuring a comprehensive and phased approach to emission reduction. The short-term measures focus on quick wins and immediate impact, while the medium and long-term strategies delve into more transformative changes, demonstrating a commitment to sustained environmental responsibility.

Figure 15 Business as usual emission projections

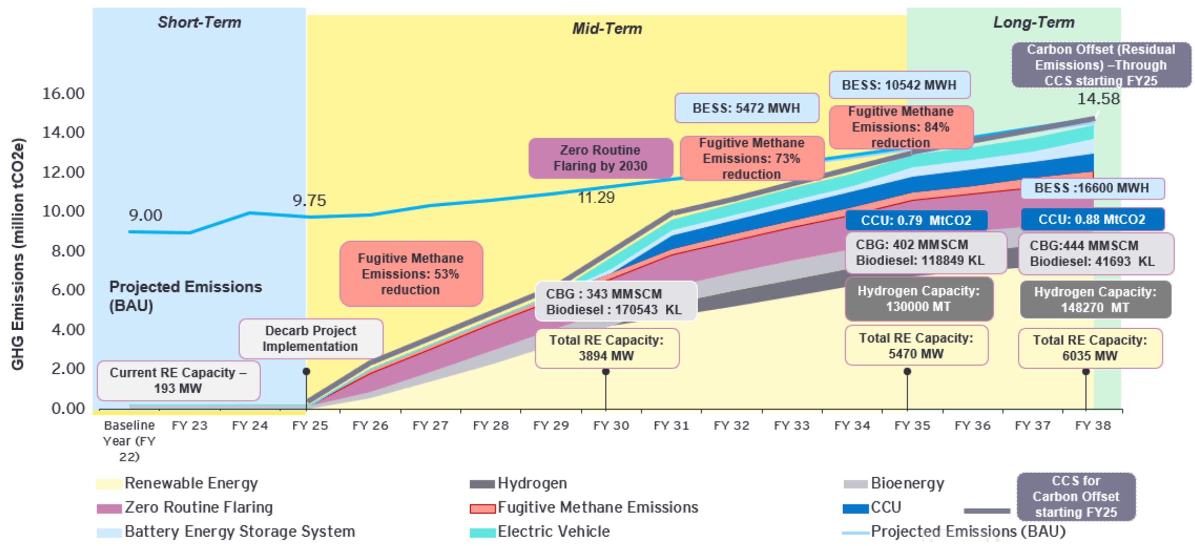


Source: EY Analysis

Emission Hotspots	Identified Levers
Captive power generation and grid electricity	• RE Hybrid (30% solar, 70% wind), Offshore wind
Gas flaring	• Zero routine flaring by 2030 (Technology adoption)
Acid gas venting (Hazira and Uran)	• Carbon Capture and Utilization and CO_2 transportation to nearby industry
Fugitive Methane Emissions	• Technology adoption
Fuel combustion (Natural gas as a fuel) in plants	• 80 % Compressed Biogas + 20% Green Hydrogen Blending
Fuel combustion (Natural gas as a fuel) in onshore assets	• Green Hydrogen
Diesel (offshore logistics and corporate services)	• EV
Diesel (onshore and offshore operations)	• Initially biodiesel shall be used and post 2030 BESS
Carbon offsetting	• CCS, alternatively afforestation / nature-based solutions may be deployed

The proposed decarbonization levers encompass a range of initiatives, including technological advancements, operational optimizations, and potential shifts in energy sources. By embracing these levers, ONGC aims to proactively contribute to a low-carbon future. Through a systematic deployment of various decarbonization measures, ONGC's pathway showcases a decline in emissions, affirming the pledge for net zero in Scope 1 and Scope 2 emissions by 2038:

Figure 16 ONGC decarbonisation roadmap



Location wise breakup of roadmap for major workcenters by emission are given in Annexure 9.

6. Renewable Energy

6.1. Context Setting

Renewable energy is generated from natural resources capable of naturally renewing within a human lifetime, without exhausting the Earth's resources. These resources, including sunlight, wind, rain, tides, waves, biomass, and the thermal energy stored in the Earth's crust, offer the advantage of widespread availability in various forms across the globe.

The deployment of renewables in the power, heat and transport sectors is one of the main enablers of keeping the rise in average global temperatures below 1.5°C. Renewables, including solar, wind, hydropower, biofuels and others, are at the centre of the transition to less carbon-intensive and more sustainable energy systems. Generation capacity has grown rapidly in recent years, driven by policy support and sharp cost reductions for solar photovoltaics and wind power.[10]

6.2. Global renewable energy scenario

The world is on course to add more renewable capacity in the next five years than has been installed since the first commercial renewable energy power plant was built more than 100 years ago. Recent progress has been promising, and 2022 was a record year for renewable electricity capacity additions, with annual capacity additions amounting to about 340 GW.

Almost 3700 GW of new renewable capacity will come online over the 2023-2028 period, driven by supportive policies in more than 130 countries. Over the coming five years, several renewable energy milestones are expected to be achieved:

1. In 2024, wind and solar PV together generate more electricity than hydropower.

2. In 2025, renewables surpass coal to become the largest source of electricity generation.

3. Wind and solar PV each surpass nuclear electricity generation in 2025 and 2026 respectively.

4. In 2028, renewable energy sources account for over 42% of global electricity generation, with the share of wind and solar PV doubling to 25%.

New policies introduced in 2022 in the biggest global economies are expected to boost renewable energy use. Countries and regions making notable progress in advancing renewables include:

- China continues to lead in terms of renewable electricity capacity additions, with 160 GW added in 2022, almost half of all global deployment. The 14th Five-Year Plan for Renewable Energy, released in 2022, provides ambitious targets for renewable energy use, which should spur investment in the coming years.
- The European Union is accelerating solar PV and wind deployment in response to the energy crisis, with more than 50 GW added in 2022, an almost 45% increase compared to 2021. New policies and targets proposed in the REPowerEU Plan and The Green Deal Industrial Plan are expected to be important drivers of renewable energy investments in the coming years.

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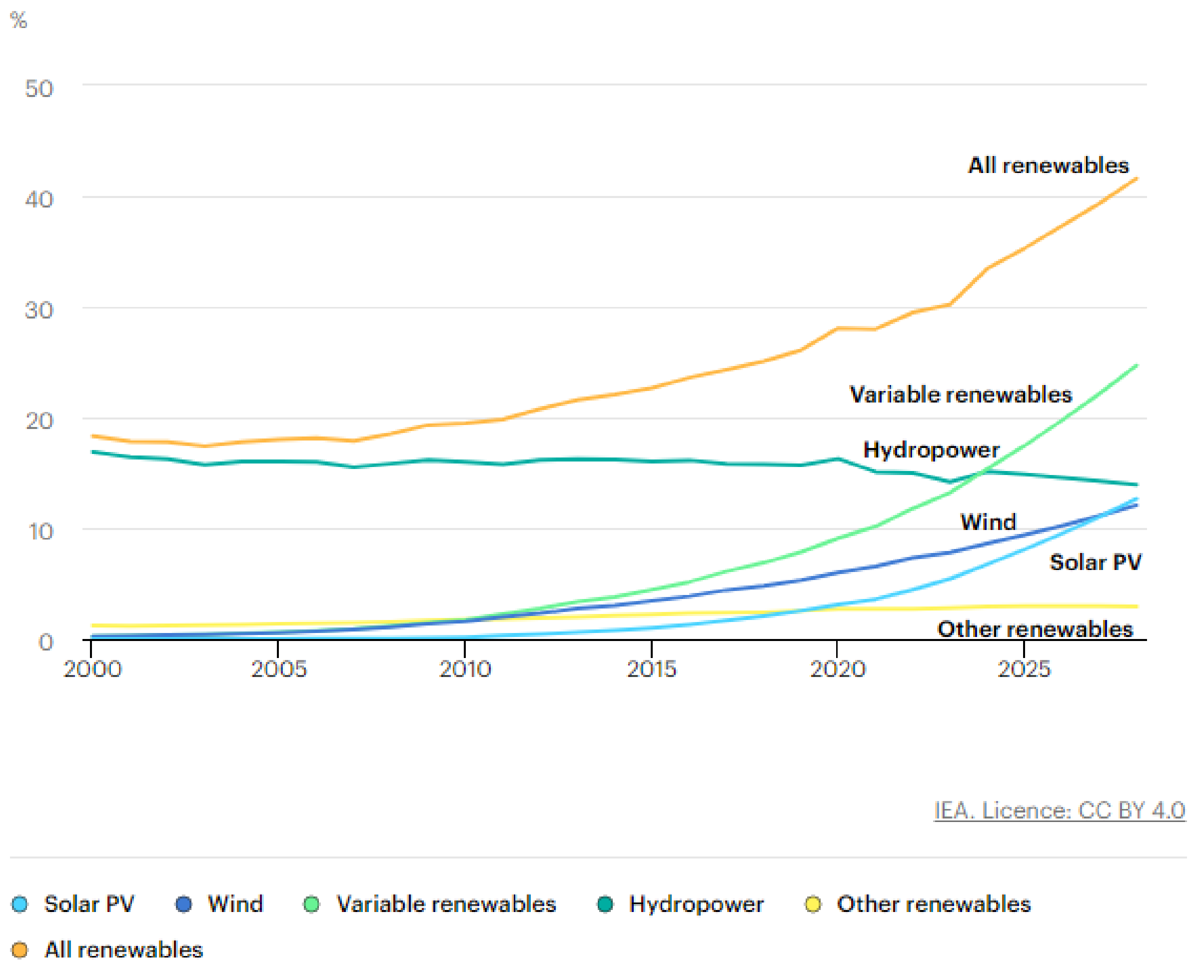
[10] Renewables - Energy System - IEA

- The United States announced important new funding in 2022 under the IRA, which is expected to advance deployment of renewables in the medium term, and to boost investment in both power plants and equipment manufacturing. [11]

Figure 17 Renewable energy generation projection



Source: International Environment Agency

India ranks 4th worldwide in installed Renewable Energy (RE) capacity. It has undertaken emission reduction goals, including decreasing the nation's economic carbon intensity by over 45% by the end of the decade, achieving 50% of its cumulative electricity generation from renewables by 2030, and attaining net-zero carbon emissions by 2070. Additionally, India targets the installation of 500 GW of renewable energy capacity by 2030 as part of its sustainable energy strategy.[12]

[11] Executive summary – Renewables 2023 – Analysis - IEA
[12] Renewable Energy in India - Indian Power Industry Investment (investindia.gov.in)

Global peers and their renewable energy targets are as follows:

Figure 18 Renewable energy targets of Oil and Gas companies

Company	Unit	2021	2022	2024	2025	2030	2035	2050
BP	Renewable (solar + wind) capacity (GW)	4.4			20	50		
Eni	Renewable (solar + wind) capacity (GW)	1.1	2	4	>6	>15	>30	60
Repsol	Renewable (solar + wind) capacity (GW)	1.7			6	20		
Total Energies	Renewable (solar + wind) capacity (GW)	10			35	100		
Chevron	Power demand sourced from renewables (GW)				0.5			
Suncor Energy	Wind power generation capacity (GW)				~0.264			

Source : Renewable capacity highlights 2022 (irena.org)

6.3. Policy scenario in India

Figure 19 RE policy options in India

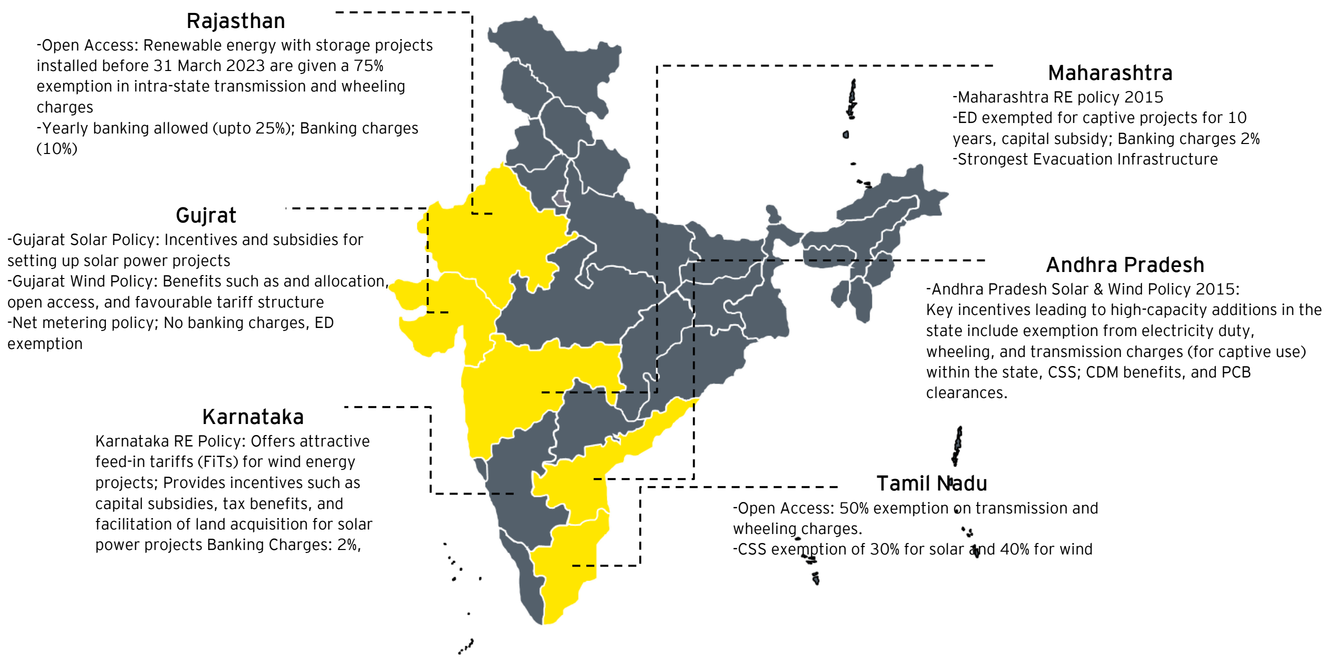


Table 11 State wise RE Potential

State	Solar (GW)	Wind (GW)	Biomass (GW)	Hydro (GW)
Andhra Pradesh	38.44	4.10	1	0.41
Assam	13.76	-	0.22	0.20
Gujarat	35.77	10.90	1.68	0.20
Maharashtra	64.32	5.08	3.42	0.79
Tamil Nadu	17.67	10.15	1.67	0.60

Source: MNRE

6.4. Renewable energy technologies

Solar Power

Solar technologies convert sunlight into electrical energy either through photovoltaic) panels or through mirrors that concentrate solar radiation. In India, 4 states - Rajasthan (17 GW), Gujarat (9 GW), Tamil Nadu (7 GW), and Karnataka (8GW) account for ~63% of the installed capacity. It can deliver heat, cooling, natural lighting, electricity, and fuels for a host of applications. Solar Technology options available are:

- Grid Connected Solar PV
- Ground Mounted Solar PV
- Solar Rooftop

- Off-grid Solar
- Hybrid power systems

Wind Power

Wind energy harnesses the kinetic energy of moving air by using large wind turbines located on land (onshore) or in sea- or freshwater (offshore). Onshore and offshore are 2 technologies available for wind Power. In India, 4 states - Rajasthan (5GW), Gujarat (10GW), Maharashtra (5GW), Tamil Nadu (10GW) and Karnataka (5GW) account for ~83% of the installed capacity.

Bio-Power

Bioenergy is produced from a variety of organic materials, called biomass, such as wood, charcoal, dung and other manures for heat and power production, and agricultural crops for liquid biofuels. In India, UP (2.2 GW), Maharashtra (2.6 GW), Tamil Nadu (1 GW), and Karnataka (1.9GW) account for ~72% of the installed capacity. Various Bio-Power Technologies available are:

- Bagasse Cogeneration
- Non-bagasse Cogeneration
- Waste-to-Energy

Hydropower

Hydropower harnesses the energy of water moving from higher to lower elevations. It can be generated from reservoirs and rivers. In India, Karnataka (1.3 GW), Maharashtra (0.4GW), Himachal Pradesh (1 GW), and Kerela (0.3 GW) account for ~59% of the installed capacity There are 2 technologies of Hydropower available:

- Large Hydropower – Power plants with a capacity of more than 30 MW
- Small Hydropower - Power plants with a capacity of 100 kw to 10 MW
- Micro Hydropower – Power plants with a capacity less than 10 kw

Ocean Energy

Ocean energy derives from technologies that use the kinetic and thermal energy of seawater - waves or currents for instance - to produce electricity or heat. India has a total potential of 12.5 GW of Ocean Energy.

Geothermal Energy

Geothermal energy utilizes the accessible thermal energy from the Earth's interior. Heat is extracted from geothermal reservoirs using wells or other means. India has a total potential of 10 GW Geothermal energy.

6.5. Renewable energy procurement model

- **For Onsite** – There are options like Rooftop solar Investment, Co-located biomass co-generation plants, RESCO (Renewable Energy Service Company), Modular Onsite Wind Turbines

- **For Offsite** - There are options 100% self-investment Captive, Partial owned (26% equity) Group Captive, Third Party Open Access, Green Energy Markets, DISCOM Green Tariffs

Details about the models:

- **Third-Party Open Access-** Businesses can access solar energy without owning the infrastructure. Solar providers install and manage solar systems, while customers purchase the generated electricity at competitive rates, reducing costs and environmental impact, with no upfront investment in equipment or maintenance.
- **Group Captive** – Group Captive is a shared solar power generation arrangement where multiple entities, often from the same corporate group or industrial cluster, collectively invest in and own a solar facility. They benefit from the electricity it generates and typically use it to meet their own energy needs, reducing costs and environmental impact.
- **Renewable Energy Service Company (RESCO)** - It is an arrangement where a third-party provider installs, owns, operates, and maintains renewable energy systems, such as solar panels, on a customer's premises. The customer then purchases the generated energy from the RESCO provider at an agreed-upon rate, often with no upfront costs.
- **Green Energy Markets** - Green energy markets refer to the buying and selling of electricity generated from renewable sources like wind, solar, and hydropower. Participants include producers, consumers, and traders who trade renewable energy certificates (RECs) to meet renewable energy targets, reduce carbon footprints, and support sustainable energy sources while ensuring grid reliability and economic efficiency. Example of Green Market in India are – IEX, PXIL

Table 12 Capex and Opex for Renewable Energy

Resource	Capex (INR Crore/MW)	O&M Fixed Cost (INR/MW)	Construction Time (in years)	Amortization/ Lifetime (in years)
Solar	4.5-5	1% of Capex	0.5	25
Wind (onshore)	6-7	1% of Capex	1.5	25
Wind (offshore)	16.6	1% of Capex	1.5	25
Small Hydro	8-11	2.5% of Capex	5-8	40
Biomass	9	2% of Capex	3	20
Battery Energy Storage System	9.3 (5-hour storage)	1% of Capex	0.5	14
Inter-regional Transmission line cost	10,613/MW-km	-	1	25

6.6. Emission reduction potential for ONGC

ONGC aims to minimize emissions by adopting renewable energy sources for internal operations, particularly through onshore wind and solar installations in India. Transitioning to RE power can significantly reduce captive power generation emissions and decrease reliance on grid electricity purchases, starting from fiscal year 2026.

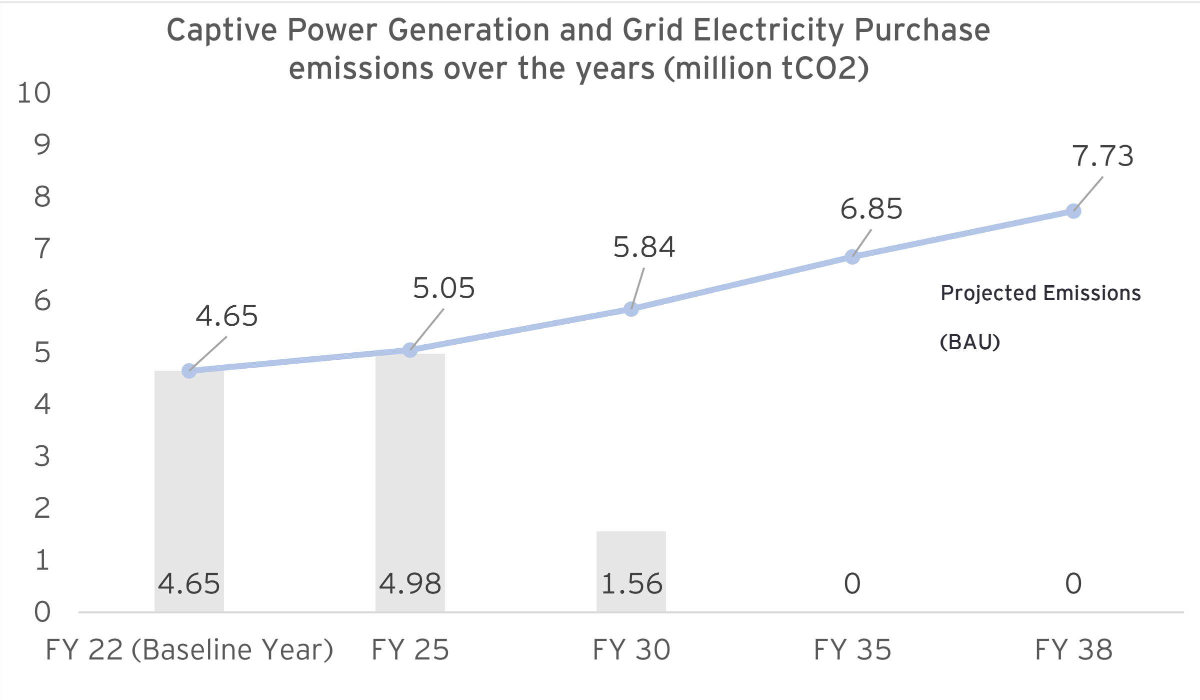
The Government of India (GoI) has a target of 500 GW of renewable energy by 2030 and state-wise incentives for RE power across India. ONGC can collaborate with the GoI to leverage the country's target of 30 GW offshore wind capacity and associated incentives, enabling the electrification of offshore assets.

In the North-eastern Region, ONGC plans to capitalize on the substantial potential for small hydro projects, targeting electrification of assets in that area starting from fiscal year 2030, with an implementation timeline of 5-8 years.

Renewable Energy Penetration by 2038

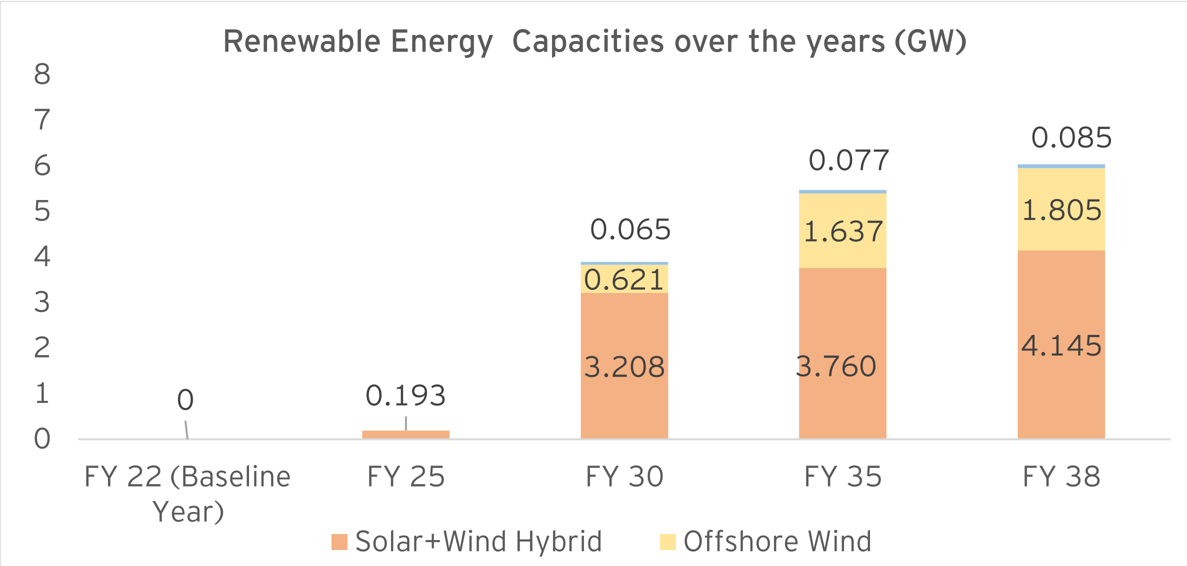
The Projected emissions from purchased electricity and captive generation for ONGC in Business-as-usual scenario is expected to increase from 4.65 Million tCO_2 in FY22 to 7.73 Million tCO_2 in FY38. To reduce these emissions, ONGC needs to switch from Grid energy to Renewable energy. The Below graph shows the emission projection in Business as usually scenario vs the emission projections with renewable energy initiatives, from baseline year, FY22 to the target year, FY38.

Figure 20 Captive Power Generation and Purchased electricity Emissions.



Below graph shows that the renewable energy capacity in expected to grow from 0.19 GW in FY22 to 6.035 GW in FY38 to replace Captive Power Generation through NG and grid electricity with renewable energy.

Figure 21 RE Capacity over the years



Below table shows state-wise RE penetration for FY 2038:

*Table **13** State wise projected RE penetration by FY 2038*

State	Renewable Lever	Projected Capacity (In MW)	CAPEX (in Mn INR)	OPEX (in Mn INR)	Emission Reduction (In Mn tCO2e)	Savings (in Mn INR/ Annum)	Payback (Years)
Gujarat	RE- Hybrid	801.56	44651.38	446.51	0.78	5025	8-9
Maharashtra	RE- Hybrid	3120.63	414835.3	2788.37	6.41	32058	9-10
	Offshore Wind	1759.02					
Tamil Nadu	RE- Hybrid	28.41	1620.46	16.20	0.02	151.65	10-11
Andhra Pradesh	RE- Hybrid	194.74	18950	189.50	0.29	1777.37	8-9
	Offshore Wind	46.25					
Assam	Small Hydro	84.61	8029.62	200.74	0.23	711.77	11-12
Total		6035	488086.80	3641.32	7.73	39723.79	

Table 14 Assumptions for Renewable Energy penetration

Year	Particulars	Unit	Scope 1	Scope 2	% change Y-o-Y (Scope 1)	% change Y-o-Y (Scope 2)
Till 2025	% overall reduction from assets in Guj, TN, Others	%	0%	0%		
2026	% overall emission reduction from assets in Gujarat, Tamil Nadu, and Other	%	8%	78%		
Till 2026	% reduction in emission from assets in Maharashtra and AP	%	0%	0%		
2030	% overall emission reduction from assets in Maharashtra and AP using hybrid RE	%	45%	7%	11.17%	1.83%
2035	% overall emission reduction from assets in Maharashtra and AP using offshore wind	%	45%	7%	4.96%	0.81%
Till 2030	% reduction in emission from assets in Assam	%	0%	0%		
2033	% overall emission reduction from the assets in Assam	%	3%	7%	0.98%	2.41%

RE Hybrid - Wind (70%) - Solar (30%)		
Capacity by 2030:	4,145	MW
Project Start Year:	2026	FY
Service Duration until 2038:	13	years
Carbon Abatement by 2038:	54.35	Mn tCO_2e
Capital Investment:	2,30,937	Mn INR
OpEx Share:	1%	of CapEx
OpEx Escalation Y-o-Y:	5%	assumed
Total OpEx by 2038:	40,906	Mn INR
Discount rate for NPV:	10%	assumed
NPV of Total Costs:	2,31,280	Mn INR

Offshore Wind		
Capacity by 2038:	1,805	MW
Project Start Year:	2027	FY
Service Duration until 2038:	12	years
Carbon Abatement by 2038:	39.83	Mn tCO_2e
Capital Investment:	2,49,120	Mn INR
OpEx Share:	1%	of CapEx
OpEx Escalation Y-o-Y:	5%	assumed
Total OpEx by 2038:	39,653	Mn INR
Discount rate for NPV:	10%	assumed
NPV of Total Costs:	2,49,097	Mn INR

Small Hydro		
Capacity by 2030:	85	MW
Project Start Year:	2031	FY
Service Duration until 2038:	8	years
Carbon Abatement by 2038:	1.84	Mn tCO_2e
Capital Investment:	8,030	Mn INR
OpEx Share:	2.5%	of CapEx
OpEx Escalation Y-o-Y:	5%	assumed
Total OpEx by 2038:	1,917	Mn INR
Discount rate for NPV:	10%	assumed
NPV of Total Costs:	9,420	Mn INR

Table 15 Land requirements for Solar and Wind Power Plant

State	Renewable Lever	Projected Capacity (in MW)	Solar Capacity (in MW)	Land Requirement (in Acres)	Wind Capacity (in MW)	Land Requirement (in Acres)
Gujarat	RE- Hybrid	801.56	240.468	961.872	561.09	981.90
Maharashtra	RE- Hybrid	3120.63	936.189	3744.756	2184.441	3822.77
Tamil Nadu	RE- Hybrid	28.41	8.52	34.08	19.88	34.79
Andhra Pradesh	RE- Hybrid	240.99	72.29	289.16	168.69	295.20

Assumptions:

1. RE-Hybrid includes 30% solar energy and 70% wind energy.
2. For Solar, the land requirement is taken as 4 Acres/MW as per the CEA electricity plan 2022.
3. For Wind, the land requirement is taken as 1.75 Acres/MW as per the CEA electricity plan 2022.

6.7. Case studies

Offshore Wind: Hywind Tampen project by Equinor

The Hywind Tampen project, led by Equinor with support from partners like Petoro and OMV, is a big step in producing clean energy. They've set up wind turbines floating on the sea, about 140 kilometers from the shore and in deep waters. These turbines, with a combined capacity of 88 MW, help generate electricity without emitting harmful CO2 gases, reducing emissions by 0.2 million tonnes yearly. The project received significant funding from Enova and the Business Sector's NoX Fund to promote offshore wind technology and cut down on pollution.

Conoco Phillips

ConocoPhillips established a multi-disciplinary Low Carbon Technologies organization to support the company's net-zero road map for scope 1 and 2 emissions, understand the new energies landscape, and prioritize opportunities for future competitive investment. ConocoPhillips completed pre-development work to evaluate large scale wind energy opportunities to power their operations in the Permian, North Sea and Bohai Bay.

Occidental Petroleum

Occidental announced the start-up of the company's first solar facility to directly power an enhanced oil recovery field operation in the Permian Basin. The company, through its Oxy Low Carbon Ventures (OLCV) subsidiary, also announced that it has signed a long-term power purchase agreement for 109MW of solar energy, beginning in 2021, for use in its Permian operations.

Electrification- ADNOC

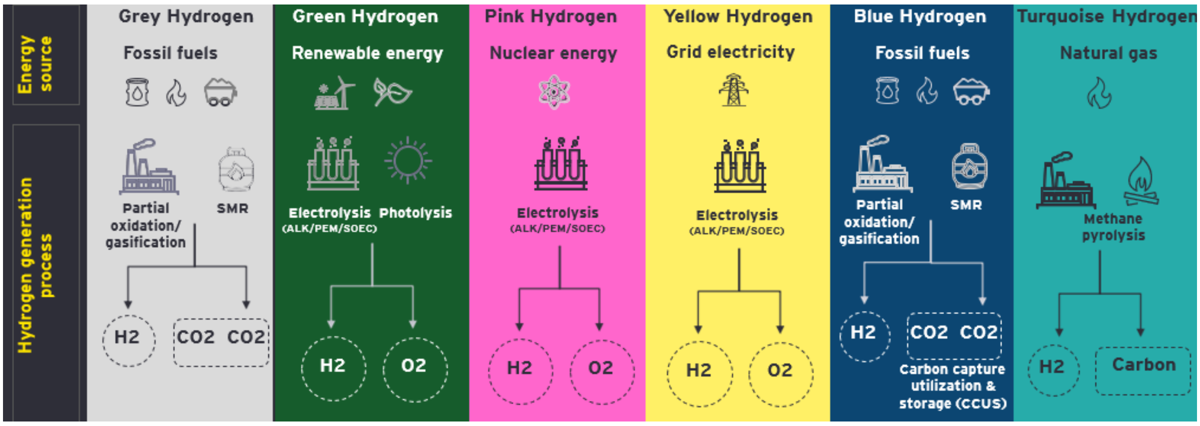
ADNOC has teamed up with the Emirates Water and Electricity Company (EWEC) to invest USD 3.6 billion in a new sub-sea transmission network. This project aims to cut the offshore carbon footprint by more than 30%. Together, they're working to supply up to 100% of power needs using a mix of nuclear and solar energy.

7. Green Hydrogen

7.1. About Green Hydrogen

Green hydrogen is defined as hydrogen produced by splitting water into hydrogen and oxygen using renewable electricity. This is a very different pathway compared to both grey and blue. Grey hydrogen is traditionally produced from methane (CH_4), split with steam into CO_2 – the main culprit for climate change – and H_2, hydrogen. Grey hydrogen has increasingly been produced also from coal, with significantly higher CO_2 emissions per unit of hydrogen produced, so much that is often called brown or black hydrogen instead of grey. Blue hydrogen follows the same process as grey, with the additional technologies necessary to capture the CO_2 produced when hydrogen is split from methane (or from coal) and store it for long term.[13]

Figure 22 Type of Hydrogen



Green hydrogen has emerged as a pivotal technical solution in the global endeavour to decarbonize sectors that have long been resistant to traditional emission reduction methods. Industries such as steel, cement, and chemicals, often dubbed "hard to abate," are characterized by energy-intensive processes deeply entrenched in fossil fuel usage. One of green hydrogen's distinguishing technical features lies in its high energy content per unit mass, making it an ideal candidate to meet the energy demands of heavy industries. Hydrogen's energy density of approximately 120 MJ/kg, coupled with its ability to be converted back into electricity or heat, offers a versatile means to power intricate industrial processes. In order to align with both domestic and global shifts towards clean energy, the utilization of green hydrogen will assume a crucial function in addressing challenging sectors.[14]

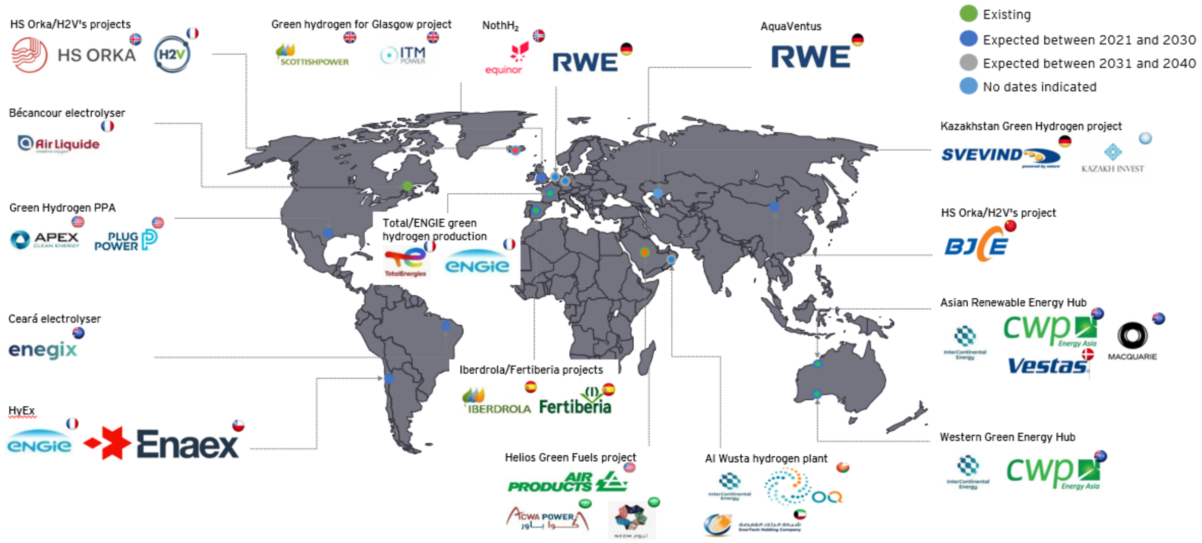
Global hydrogen demand by sector is expected to increase significantly in 2030 and boom further in 40's and 50's. The current scenario combined with government policies is expected to boost investments in green hydrogen production facilities.

[13] What is green hydrogen? An expert explains its benefits | World Economic Forum (weforum.org)

[14] The Role of Hydrogen in Decarbonizing Energy Sector; EY GDS Enterprise Applications, EY Analysis

7.2. Green hydrogen production projects

Figure 23 Global green hydrogen projects

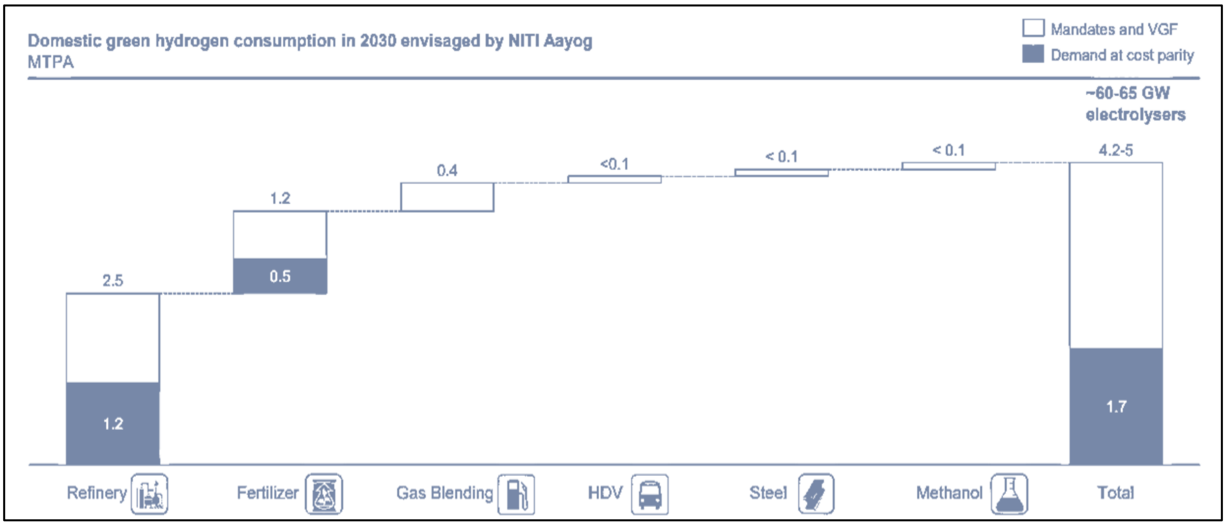


Sources: GlobalData, companies' websites, EY analysis.

7.3. India's push for hydrogen

India has established a Green Hydrogen Policy to enable renewable energy transition. It intends to provide green hydrogen fuel producers with incentives amounting to a minimum of 10% of their expenses through a program valued at $2 billion, which is scheduled to commence by the end of June 2023[15]. The government has set an ambitious objective of

Figure 24 Government Envisaged 2030 Green Hydrogen Consumption



[15] The Role of Hydrogen in Decarbonizing Energy Sector; EY GDS Enterprise Applications, EY Analysis

producing roughly 5 million tons of green hydrogen by 2030 under its green hydrogen mission. To attain this goal, India will need approximately 115 GW of continuous renewable power generation capacity and a supply of about 50 billion liters of fresh water[16].

7.4. Demand for Hydrogen

Crude oil Refining

The demand for hydrogen in refineries is substantial and continues to grow as the industry seeks more efficient and environmentally friendly processes. The crude oil refining sector's requirement for hydrogen in desulfurization is predicted to be around 3.2 million tons by 2030 and 5 million tons by 2050 . It is a crucial element in refining operations, primarily used for hydrocracking and hydrotreating processes that help remove impurities and enhance the quality of refined products such as gasoline and diesel. India ranks among the highest hydrogen consumers, with an annual domestic production and consumption totaling 6 million metric tonnes[17]. The primary utilization of hydrogen is concentrated within two key sectors one of which is within the refinery sector, comprising 46% of consumption, where hydrogen plays a crucial role in hydro-desulfurization processes.

Ammonia

The industrial production landscape is undergoing a transformation towards the utilization of renewable ammonia. Announced renewable ammonia plant capacities are projected to reach 15 Mt per annum by the year 2030. While a substantial pipeline of 71 Mt extends into 2040, investment determinations for most of these projects are still pending. Anticipations highlight that renewable ammonia will take precedence in all new capacity installations after the year 2025. Emerging applications include the use of renewable ammonia as a zero-carbon fuel within the maritime domain and for generating stationary power.

Methanol

Methanol, the second most prominent industrial application of hydrogen, serves primarily as an intermediary agent for the synthesis of various chemicals. Its most significant outcome is formaldehyde, which accounts for the highest volume and is utilized in the creation of resins employed across sectors such as construction, automotive, and consumer goods. Additionally, there are several vital fuel applications associated with methanol, including both its direct use and its conversion into other compounds, with examples like methyl-tert-butyl ether.

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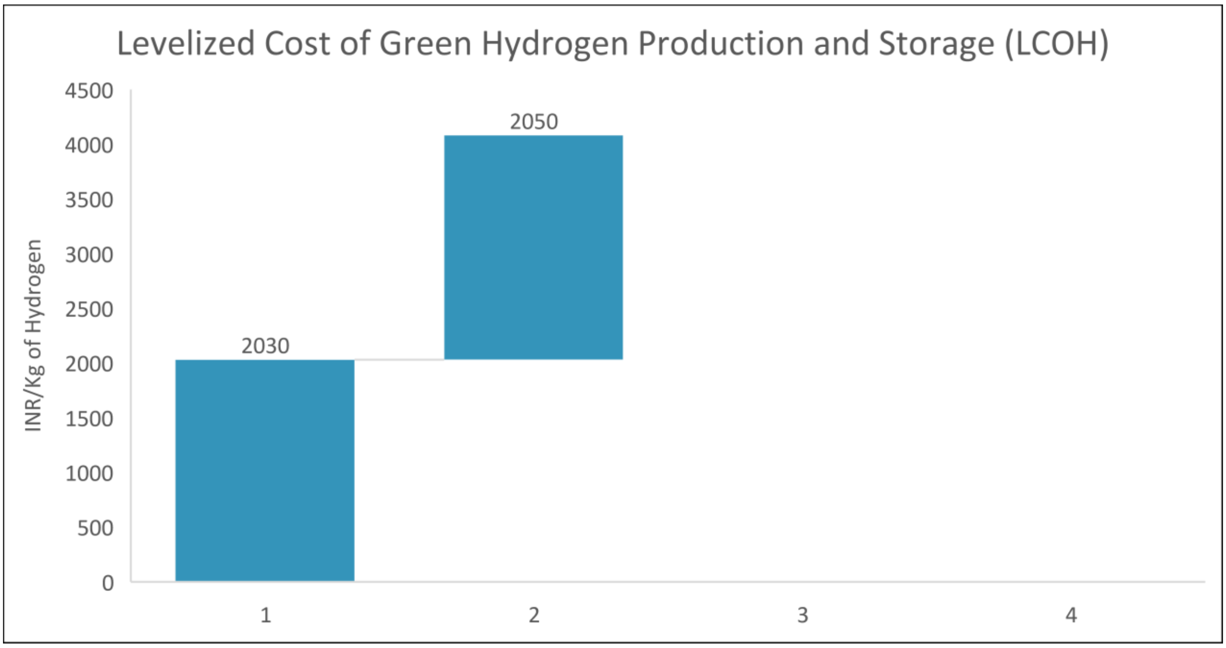
[16] EY Analysis: Accelerating Green Hydrogen Economy Prepared for India

[17] Source: TERI; MNRE; NITI Aayog

7.5. Cost analysis

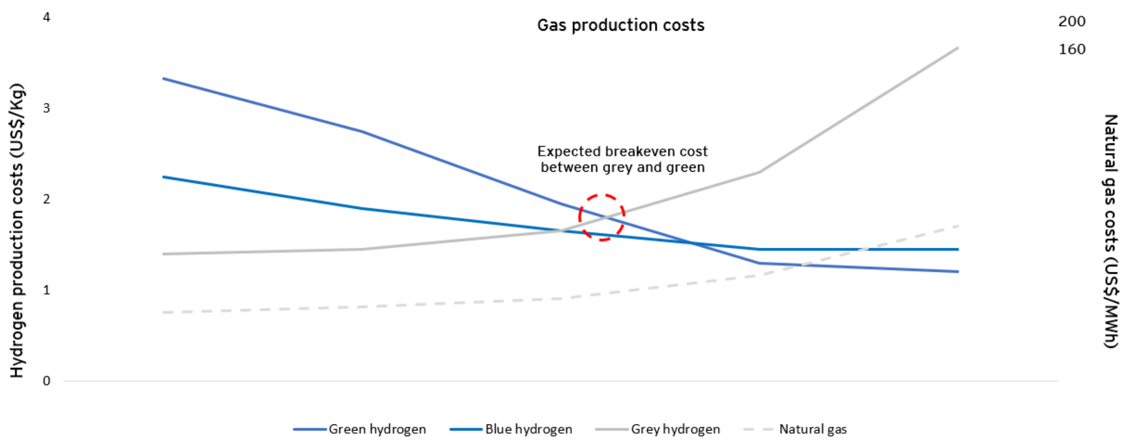
The projected cost of green hydrogen production, as calculated for a 1MW Alkaline electrolyser, is expected to be around INR 430 per kilogram. Within this estimate, about 42% of the levelized cost would be allocated to establishing a continuous renewable power (RTC) plant, while 34% would cover the electrolyser stack. Additionally, 16% would account for the compressor, and the remaining 8% would go towards the pressure vessel and storage.

Figure 25 Levelised cost of green hydrogen production and storage



Based on global gas productions costs green hydrogen is expected to breakeven with other modes of hydrogen production in the 30s. This will mainly be due to decreasing renewable costs, rapid technology development and rising CO2 costs.

Figure 27 Production cost of green hydrogen



Sources: Bloomberg, IRENA, Hydrogen Council, Gas Exporting Countries Forum, EY analysis.
Note: 1. Takes into account increase in CO_2 costs ; The prices for hydrogen production costs have been converted from US$/ MWH to US$/kg based on: USD 1.3-4.5/kg H2 (equivalent to USD 39-135/MWh) (Source: IEA)

Green hydrogen production costs expected drop by 2030 owing to decreasing renewable cost, technology development and increasing CO2 emission costs.

Figure 28 Projected cost of green hydrogen over the years

		2010	2020	2030
Decreasing renewable cost	Renewable energy cost	324 $/MWh	48 $/MWh	21 $/MWh
Technology Development*	Overall electrolyser system capex	1,800 $/kW	1,080 $/kW	~400 $/kW
Increasing CO_2 emission cost	CO_2 price evolution**	~15*** $/ton	~35 $/ton	~100 $/ton

Source: EY Analysis.
Note: *On top of cost reduction, improvements are expected in load factor and energy efficiency; ** EU carbon pricing market; *** After 2010, EU carbon pricing dropped until 2018, when it started to rise quickly.

7.6. Emission sources and abatement

Role of Renewables

Increasing the renewable electricity capacity in excess of the electrolyser capacity is another strategy that can heighten the total operational hours of the electrolyser and subsequently boost hydrogen production. This approach may lead to the curtailment of excess renewable electricity during periods of peak generation unless there are alternative users or applications available.

There are several methods available for enhancing the stability of hydrogen provision from fluctuating renewable sources. One approach involves the integration of diverse renewable energy facilities, such as combining solar photovoltaic (PV) and wind power generation. This combination can amplify the total annual operational hours when the system operates at full capacity.

Utilizing offshore wind power for electrolysis constitutes an alternative avenue to generate hydrogen with substantial full load hours and increased usage rates for subsequent synthesis phases. Projections indicate that by the year 2030, the global potential to produce hydrogen through offshore wind energy, costing less than USD 3 per kilogram of H2 and operating at capacity factors ranging from 50% to 75%, could amount to 250 million metric tons of H2.

Electrolysers

Numerous nations have already explicitly integrated objectives for deploying electrolysis capacity within their respective national hydrogen strategies. Green hydrogen generated through water electrolysis using renewable sources is foreseen to play a central role in the transition to sustainable energy, forming a crucial component of the clean energy landscape.

According to the 1.5°C Scenario presented by IRENA, hydrogen and its derivatives are projected to contribute to as much as 12% of the overall consumption of energy by the year 2050.

7.7. Emission reduction potential for ONGC

Green Hydrogen and Compressed Biogas (CBG)

Anticipating the viability of green hydrogen by 2030, it holds the potential to completely replace natural gas (NG) in specific applications, including Gas Dehydration Units (GDU) and Heater Treater/Bath Treater systems. By blending hydrogen (20%) into power generation by 2031, it has the capacity to reduce emissions by 12%. Additionally, by switching fuel in heater treater in 2031, it is expected to reduce emissions by 26%. In addition to the full replacement of NG, a strategic approach is envisioned for the Hazira and Uran Plant. Here, the remaining 20% of hydrogen can be effectively blended with Compressed Biogas (CBG) within Combined Heat and Power (CHP) units.

Table 16 HSD Power Generation

Hydrogen – Power Generation				
HSD			Power generation	
Year	%H2 Blending	H2 Blending Requirements	CBG Blending	CBG Capacity Required
	%	million MT	%	MMSCM
FY 26	-	-	20%	74.72
FY 27	-	-	35%	137.22
FY 28	-	-	50%	201.89
FY 29	-	-	65%	270.48
FY 30	-	-	80%	343.25
FY 31	20%	0.03	80%	354.10
FY 32	20%	0.03	80%	365.42

FY 33	20%	0.03	80%	377.23
FY 34	20%	0.03	80%	389.53
FY 35	20%	0.03	80%	402.31
FY 36	20%	0.03	80%	415.57
FY 37	20%	0.03	80%	429.32
FY 38	20%	0.03	80%	443.55

Hydrogen - GDU Fuel, Boiler/Furnace, Heater/Bath Treater		
Year	% H2 Blending	H2 Blending Requirements
	%	million MT
FY 26	-	-
FY 27	-	-
FY 28	-	-
FY 29	-	-
FY 30	-	-
FY 31	20%	0.07
FY 32	40%	0.08
FY 33	60%	0.09
FY 34	80%	0.10
FY 35	100%	0.11
FY 36	100%	0.11
FY 37	100%	0.11
FY 38	100%	0.12

Green hydrogen		
Project Start Year:	2031	FY
Service Duration until 2038:	8	years
Total Hydrogen req. by 2038:	1.00	Mn tonnes
Carbon Abatement by 2038:	7.61	Mn tCO_2e
Production cost, Green H2:	300	INR/kg
Total Production cost required:	36,957	Mn INR
Energy reqd. per kg. H2:	39.4	kWh/kg
Electrolyzer Efficiency:	80.0%	
Hydrogen Purity:	99.8%	
Total Energy Required per kg.:	47.37	kWh/kg
Total Electrolyzer Capacity reqd.:	83	MWp
Discount rate for NPV:	10%	
NPV of Total Costs:	36,957	Mn INR

Table 17 Green Hydrogen and CBG Emission Projections

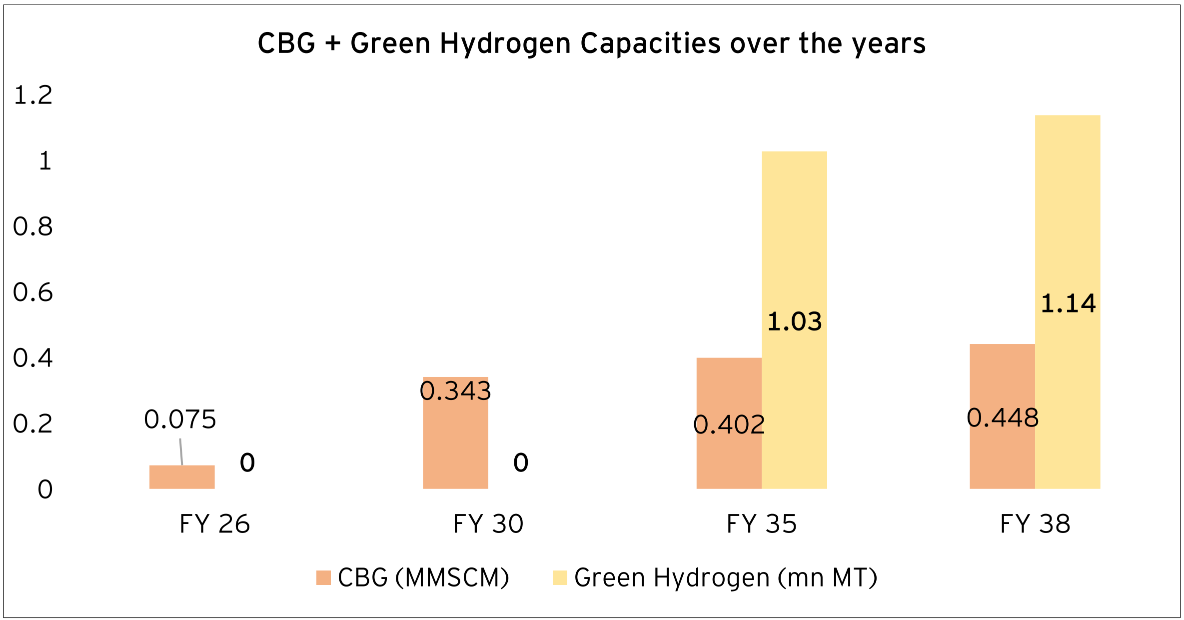
Year	CBG	Unit	Value
Till 2025	% emission reduction	%	0%
2026	% overall emission reduction from blending CBG (20%) in Power generation	%	12%
2030	% overall emission reduction from blending CBG (80%)in Power generation	%	47%

Year	Particulars	Unit	Value
Till 2030	% emission reduction	%	0%
2031	% overall emission reduction from blending H2 (20%) in Power generation	%	12%
2031	% overall emission reduction by switching fuel in GDU	%	1%
2035	% overall emission reduction by switching fuel in Boiler/Furnace	%	14%
2031	% overall emission reduction by switching fuel in Heater Treater	%	26%

As green hydrogen becomes viable in 2030, Hydrogen can entirely replace Natural Gas (NG) in some of the applications such as GDU, Heater Treater/Bath Treater. Remaining 20% hydrogen can be blended with CBG in the CHP units in Hazira and Uran Plant.

Below graph shows Green Hydrogen and CBG capacities required to achieve the emission reduction by 2038.

Figure 29 CBG and Green Hydrogen capacity required



7.8. Case Studies

Case Study: 1

HyNet North West Hydrogen project

Overview

HyNet is an integrated hydrogen production, distribution, and CCUS project, which aims to reduce the carbon emissions from industry, homes and transport sector in the North West of England. The hydrogen produced will be supplied to homes by injecting into the existing natural gas transmission system. It will also be transported to the industrial sites through a new pipeline. Phase one of the project is underway, which involves conducting pre-feed studies for CCUS, hydrogen production plant and distribution network. The commercial testing of the project will be done in its phase two (2023-26).

Project Economics

The total project cost includes:

1. Cost of Hydrogen production and CO2 capture: EUR 513 m
2. Cost of Hydrogen transport: EUR 178 m
3. Cost of Hydrogen compression and injection: EUR 78 M

The levelized cost of hydrogen will be EUR38/MWh, vs the current gas price of EUR15/MWh.

Project Outcomes

The project will save over one million tons of CO_2 emissions per year, 75% of which will be from the industries. Over two million homes and businesses in Liverpool, Manchester and parts of Cheshire will be supplied with hydrogen blended fuel for heating. The project is expected to bring in EUR31 billion of estimated Gross Value Added (GVA) for the UK economy.

Case study: 2

Audi e-Gas-Anlage Werlte Project

Overview

Audi's e-gas project in Werlte, Germany is the world's first industrial scale (>5 MW) power-to-gas application plant, which started operations in 2013.The company built the e-gas plant in collaboration with plant construction specialist SolarFuel and MT-BioMethan GmbH on land owned by German energy company EWE AG.The plant produces hydrogen through electrolysis, which is converted to methane (e-gas) using CO_2 from a nearby biogas plant run by EWE.Under a unique model, Audi passenger car drivers can purchase CNG from filling stations, post which Audi transfers an equivalent amount of e-gas into the national gas grid.

Project Outcomes

Average e-gas production from the plant is 325 standard cubic meters per hour. The E-gas produced is pumped to the national gas grid using existing natural gas pipelines.About 2,800 metric tons of CO_2 is bound every year in production of the e-gas at the plant.The plant has also qualified to participate in the power grid balancing market. Audi's e-gas plant works synergistically with the biogas plant by transferring heat to the biogas plant for continuous use, significantly increasing efficiency.By participating in the grid balancing market, Audi's e-gas plant can target higher annual operating times, increasing the amount of e-gas produced.

8. Biofuel

8.1. Context Setting

Biofuels derived from organic matter is a near carbon neutral source of fuel. It holds the distinction of being the largest contributor to renewable energy on a global scale, constituting 55% of all renewable energy and accounting for over 6% of the world's total energy supply[18].

8.2. Biofuel Scenario in India

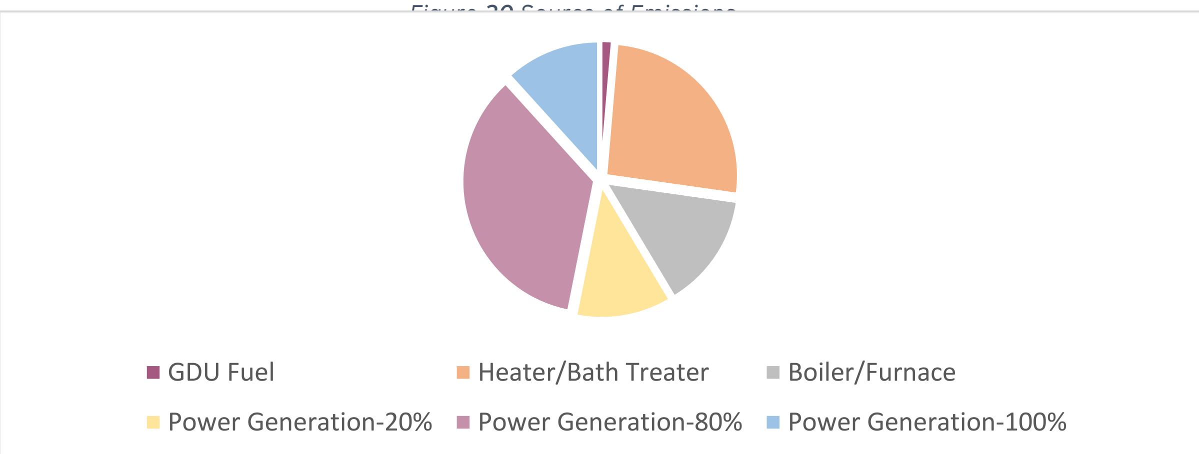
India has quickly joined the ranks of major biofuel producer and consumer thanks to a set of coordinated policies, high political support, and an abundance of feedstocks. In 2018 India released its National Policy on Biofuels which set blending targets for ethanol (20% blending by 2030) and biodiesel (5% by 2030), feedstock requirements for different fuels and laid out the responsibilities of 11ministries to coordinate government actions. Beyond blending targets, India established guaranteed pricing, long-term ethanol contracts, technical standards and codes and financial support for building new facilities and upgrading existing ones. Buoyed by its success, the Government moved the ethanol 20% volume blending target forward by 5 years to 2025-26, which was enshrined in an updated National Policy on Biofuels in 2022.

Moreover, as part of its G20 presidency, India has proposed a Global Biofuel Alliance (GBA) to bring countries together to expand and create new markets for sustainable biofuels.[19]

8.3. Emission reduction potential for ONGC

Six sources of emissions pertaining to ONGC's plants and assets have been identified. Power generation (80%) accounts for 35 % of total Scope 1 and Scope 2 emissions from plants and assets. However, the power generation (80%) emissions can be isolated to three plants. While Heater/ Bath treater accounts for a total 26% of the emissions. This source is essential

Figure 20 Source of Emissions



[18] Bioenergy - IEA
[19] Biofuel Policy in Brazil, India and the United States (windows.net)

in the initial processing and treatment of crude oil and natural gas to separate impurities and improve product quality.

8.4. Case Study

Eni's Sustainable Biofuels and Aviation Fuel

Background

Hydrotreated Biofuels: Eni produces a variety of hydrotreated biofuels, including HVO solution and HVO 100%, which are available both in pure form and in blends. These biofuels are designed to significantly reduce greenhouse gas emissions compared to traditional fossil fuels.

Aviation Fuel - SAF: Eni's commitment to decarbonizing air transport led to the development of Sustainable Aviation Fuel (SAF). SAF is produced from a biogenic component and blended with fossil fuel at a rate of 20% to create JET A1+SAF HEFA. This innovative aviation fuel provides a more sustainable alternative to traditional jet fuel.

Outcome

Eni's sustainable biofuels and SAF solutions have been available since the end of 2022, offering the aviation industry a cleaner and more environmentally friendly option. By blending biofuels with fossil fuels and providing alternatives like HVO solution and HVO 100%, Eni is making significant strides in reducing carbon emissions in the transportation sector and contributing to a more sustainable future.

Way Forward Towards Biofuels

Biofuels play a critical role in ensuring access to affordable, reliable, sustainable, and modern energy for all, which is vital in a circular economy, and helps address climate change as biofuels can cut greenhouse gas emissions by up to 46% compared to fossil fuels.

India's journey toward net-zero emissions by 2070 revolves significantly around biofuels as part of its energy transition strategy. The initiation of the Global Biofuels Alliance (GBA) during India's G20 Presidency, designed to promote collaboration and enhance the adoption of sustainable biofuels, is poised to expedite India's shift from a fossil fuel-dependent economy to one powered by cleaner energy sources.

Biodiesel		
Net Substitution by 2038:	3.02	Mn kL
Project Start Year:	2030	
Service Duration until 2038:	9	years
Carbon Abatement by 2038:	**1.55**	Mn tCO_2e
Capacity 2G Ethanol plant:	100	Mn INR
CapEx (2G Ethanol plant):	5,232	of CapEx
Capacity reqd. (2030):	467	
Capital Investment:	24,447	Mn INR
OpEx Share:	2.0%	

OpEx from Biodiesel Production by 2038:	4,400	Mn INR
Discount rate for NPV:	10%	
NPV of Total Costs:	26313	Mn INR

Biogas		
Net CBG reqd. by 2038:	444	MMScm
Net CBG reqd. by 2038:	6.18	Mn MT
Project Start Year:	2026	FY
Service Duration until 2038:	13	years
Carbon Abatement by 2038:	10.63	Mn tCO_2e
Unit cost of CBG plant:	50	Mn INR/TPD
Capacity reqd. CBG plant (2030):	0.27	Mn MT
Capacity reqd. CBG plant (2030):	904	TPD
Capital Investment:	45,195	Mn INR
Unit operational cost:	8	Mn INR/TPD
OpEx (2030 - 2038)	65,081	Mn INR
OpEx (2024 - 2029)	26,111	Mn INR
Total OpEx by 2038:	91,192	Mn INR
Discount rate for NPV:	10%	
NPV of Total Costs:	71,610	Mn INR
Net CBG reqd. by 2038:	4,204.59	MMScm

Resources, Challenges and Opportunities

As an agricultural powerhouse, India possesses abundant biomass resources in agricultural waste, forestry residues, and urban waste, making it an economically attractive alternative to fossil fuels and paving the way for a greener future. By leveraging technologies such as biomass gasification, biofuel production, and biogas generation, ONGC can diversify its energy sources, mitigate greenhouse gas emissions, and secure a more sustainable future.

Despite its widespread utility as an energy source, biomass poses certain challenges such as stubble burning by farmers in parts of northern India. However, this also presents an opportunity for ONGC to invest in technologies that can convert this waste into energy, thereby reducing emissions and contributing to cleaner air.

On the policy front, in 2018, India's Ministry of Petroleum and Natural Gas introduced the "National Policy on Biofuels" to boost domestic biofuel production and reduce petroleum imports. The policy was amended in June 2022, advancing the deadline for achieving a 20% bioethanol blend in petrol from 2030 to 2025-26 and expanding eligible feedstocks for biofuel production. This amended policy supersedes the 2009 National Biofuel Policy. Subsequently, India released a "Roadmap for Ethanol Blending in India 2020-25" based on the updated biofuels policy.

The data presented in the table below outlines a strategic roadmap indicating a shift towards increased dependence on biofuels, specifically biodiesel and compressed biogas (CBG). This transition aims to replace a notable proportion of conventional High-Speed Diesel (HSD) and integrate a considerable volume of biodiesel substitution, accompanied by the corresponding capacity requirements. The values within the table encapsulate a deliberate plan for the initiation and progressive expansion of CBG integration within the sector of power generation throughout the designated fiscal years.

9. Battery Energy Storage System

9.1. About Battery Energy Storage System

Battery Energy Storage Systems (BESS) play a pivotal role in facilitating the widespread adoption of renewable energy generation by addressing the inherent intermittency of renewable sources. These systems are indispensable in ensuring a consistent and reliable contribution to the global energy supply. As the cost of batteries continues to decline, the versatility offered by BESS becomes increasingly crucial for various applications, including but not limited to peak shaving, optimizing self-consumption, and providing backup power during outages.

9.2. Need for Energy Storage in India

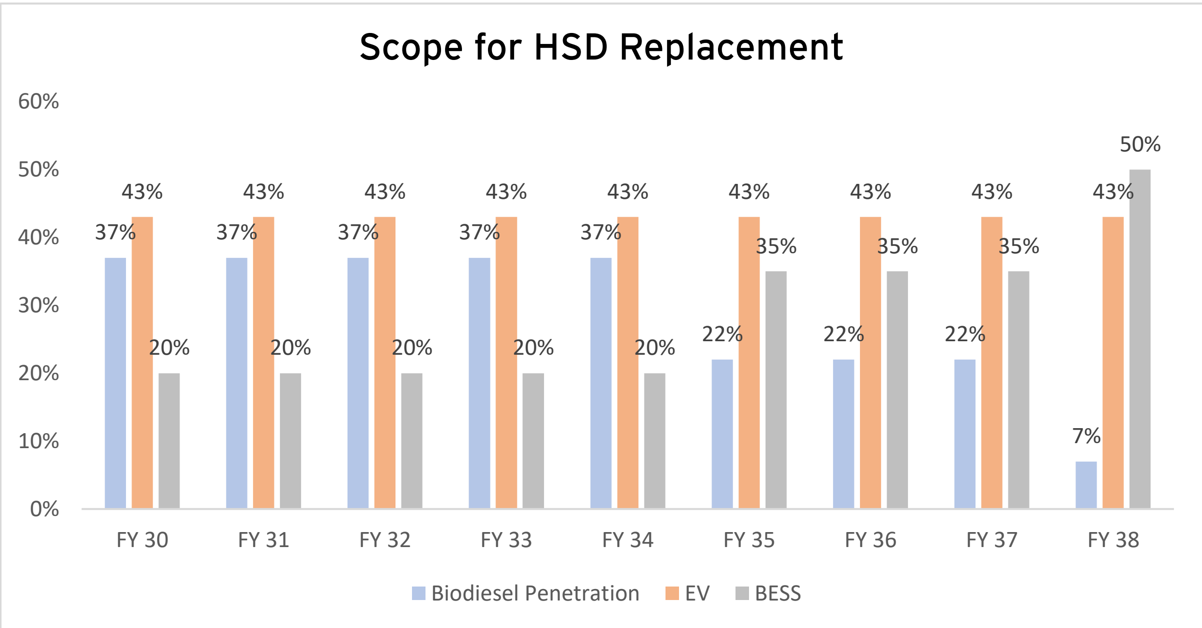
India has committed to increase its share of non-fossil fuel-based generation sources to 40% by 2030 which necessitates a demand for flexibility in power systems. The 'Power for All' target of 24x7 electricity for all by 2019 created an increase in power requirement and a need to balance the supply and demand of electricity. Energy storage will play a crucial role in increasing the system's overall flexibility by serving multiple grid applications. The recent developments in the Electric Vehicle (EV) sector and its ambitious targets will only increase the demand for energy storage systems.

Energy storage market in India witnessed a demand of 23 GWh in 2018 with 56% of the battery demand coming from power backup inverter segment. During 2019-2025, the cumulative potential for energy storage in behind the meter and grid side applications is estimated to be close to 190 GWh by India Energy Storage Alliance.

9.3. Abatement Options

Based on analysis of Scope 1 and Scope 2 emissions, it is feasible to replace High speed Diesel (HSD) with biofuels and Battery Energy and Storage Systems (BESS) over the timeline projected. Dependency on Biodiesel may be reduced with introduction of EV and BESS.

Figure 31 Scope for replacing HSD with Biofuels



ONGC can leverage the country's abundant biomass resources, capitalizing on government policies and incentives, and investing in technologies to overcome the challenges associated with biomass use. This approach will not only contribute to emission reduction but also enhance energy security and foster economic growth.

Biodiesel and BESS can replace the existing diesel generators till 2035. Below table shows the projected emission reductions from Biodiesel and BESS till 3035. Till FY 28, it is assumed that no new initiatives will be deployed. It is assumed that it takes 1 year for project implementation. So, till FY 29, no emissions reduction is possible.

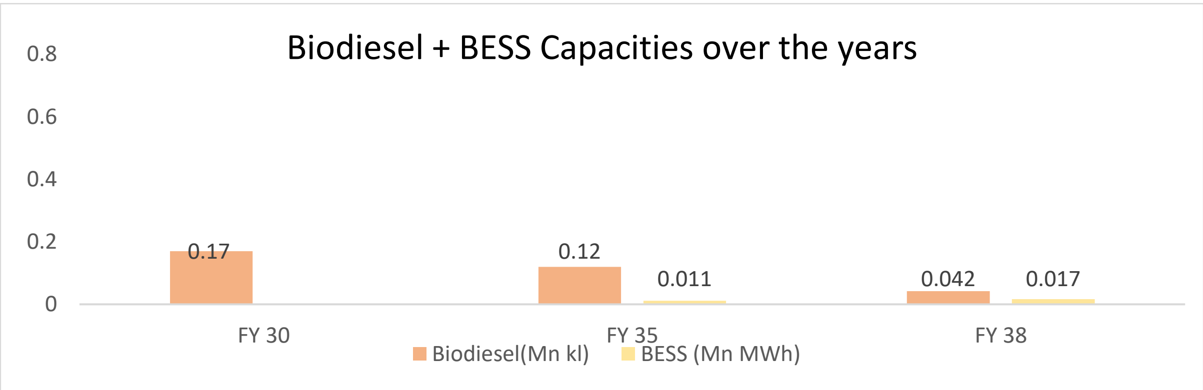
Table 18 Biodiesel and BESS Emission Projection

Year	Particulars	Unit	Value
2025-2029	% emission reduction from Biodiesel	%	20%
till 2029	% reduction from EV till 2029	%	0%
2030-2038	% overall reduction by switching to EV in Workcenters	%	43%
till 2029	% reduction from BESS till 2029	%	0%
2030-2034	% overall reduction by swtiching to BESS in Services	%	20%
2035-2037	% emission reduction from BESS	%	35%
2038	% overall reduction by swtiching to BESS in Services	%	50%

The Projected emissions for ONGC in Business-as-usual scenario is expected to increase from 0.96 million tCO_2e in FY22 to 1.61 million tCO_2e in FY38. After implementation of the biodiesel and BESS lever, there is a residual emission of 0.79 million tCO_2e which comes from the company vehicles and cannot be decreased, hence it needs to be offset by 2038.

Below graph shows Biodiesel and BESS capacities required to achieve the emission reduction by 2038.

Figure 32 Biodiesel and BESS capacity required.



10. Carbon Capture Utilisation and Storage

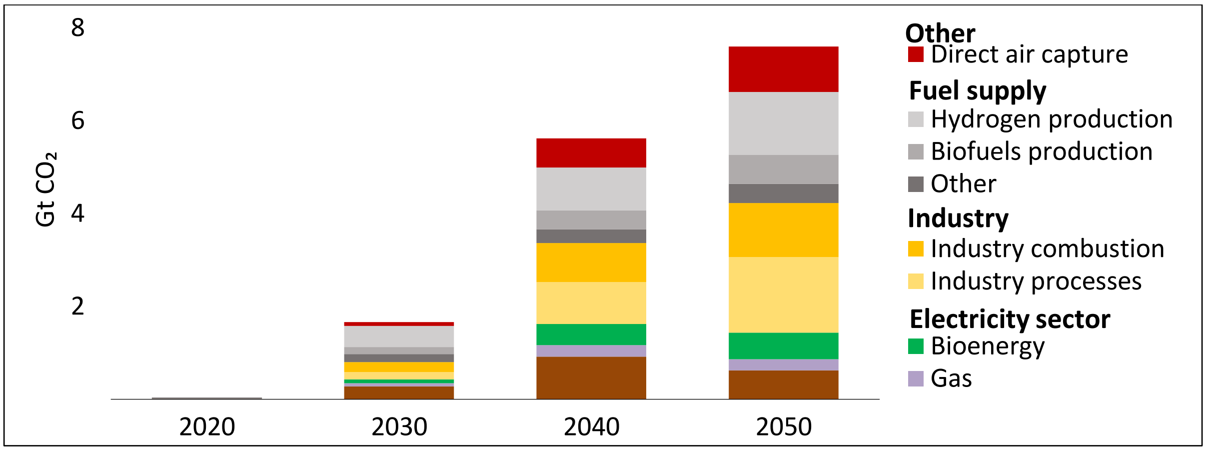
10.1. Context Setting

The Carbon Capture, Utilization, and Storage (CCUS) technology presents a means to effectively capture and utilize the significant levels of carbon dioxide (CO_2) emissions generated by industrial processes. This adaptable technology can be integrated into existing power and industrial facilities, offering a viable solution for mitigating emissions in challenging sectors such as oil and gas, cement, and steel production.

As of now, CCUS accounts for less than 1% of the overall reduction in carbon dioxide emissions. However, projections indicate a gradual increase in capture capacity within the Net Zero Emissions (NZE) framework over the next five years, with a rapid expansion anticipated over the subsequent 25 years. This growth is primarily attributed to robust policy initiatives.[20]

By the year 2030, the global annual CO_2 capture is anticipated to reach 1.6 billion metric tons, and this figure is expected to rise significantly to 7.6 billion metric tons by 2050. To support this expansion, annual investments in CCUS are projected to exceed USD 150 billion by 2050. Notably, approximately 95% of the total CO_2 captured is destined for permanent geological storage, while the remaining 5% serves as a valuable resource to produce synthetic fuels. [21]

Figure 33 Global CO2 capture by source in the NZE scenario



Source: Net Zero by 2050 - A Roadmap for the Global Energy Sector

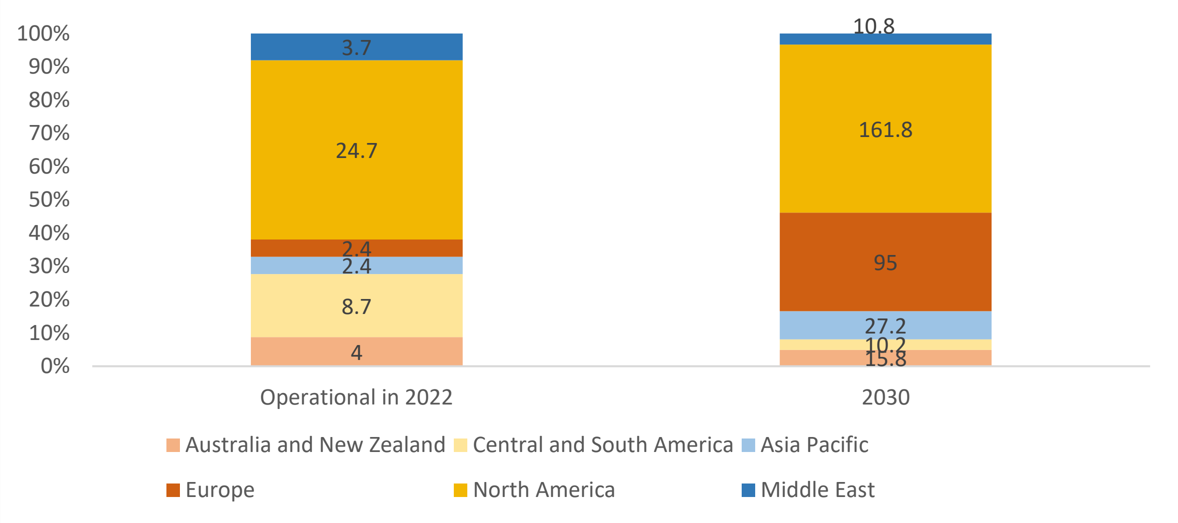
CCUS Global Scenario

Americas, particularly the US, is the global CCUS leader accounting for a major chunk of the CCUS facilities, hosting a substantial portion of CCUS facilities, backed by favourable policies and investment conditions. Over half of the world's large-scale (>2Mtpa) CCUS projects are in the Americas including 17 in the US, 3 in Canada, and 1 in Brazil. US has approximately 95 carbon capture projects which are being planned to be operational by

[20] Net Zero by 2050 - A Roadmap for the Global Energy Sector (windows.net)
[21] Net Zero by 2050 - A Roadmap for the Global Energy Sector (windows.net)

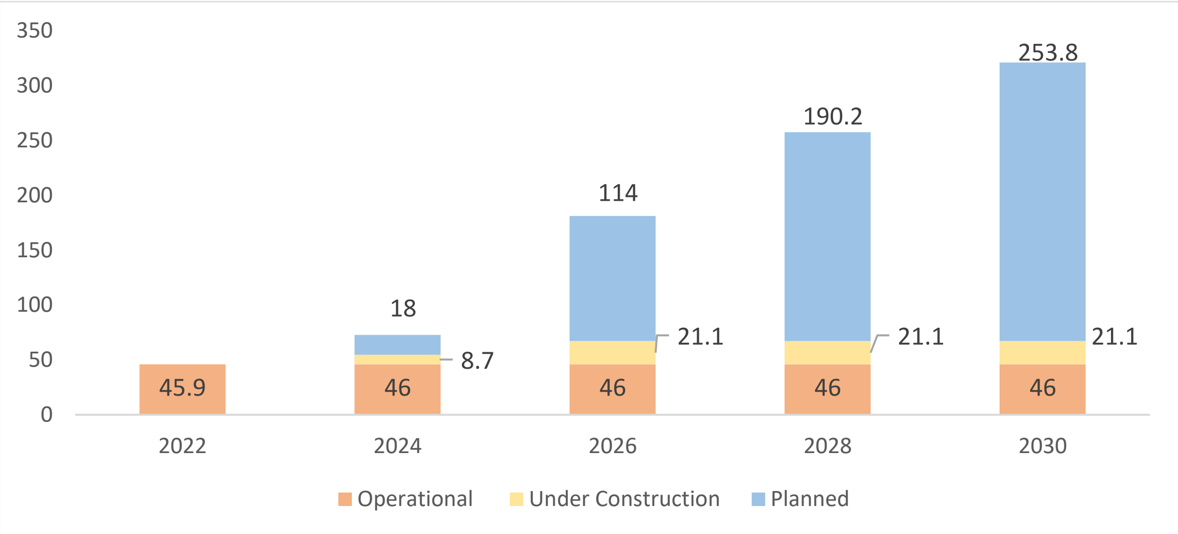
2030. This will enhance the carbon capture capacity to over 100 Mt CO2 per year. In Feb 2018, U.S. Congress extended 45Q tax credits, fostering CCUS development.[22]

Figure 34 Operational and planned capture capacity by region (Mtpa)



Source: IEA CCUS Project Explorer – Data Tool

Figure 35 Operational and planned capture capacity (Mtpa)



Source: IEA CCUS Project Explorer - Data Tool

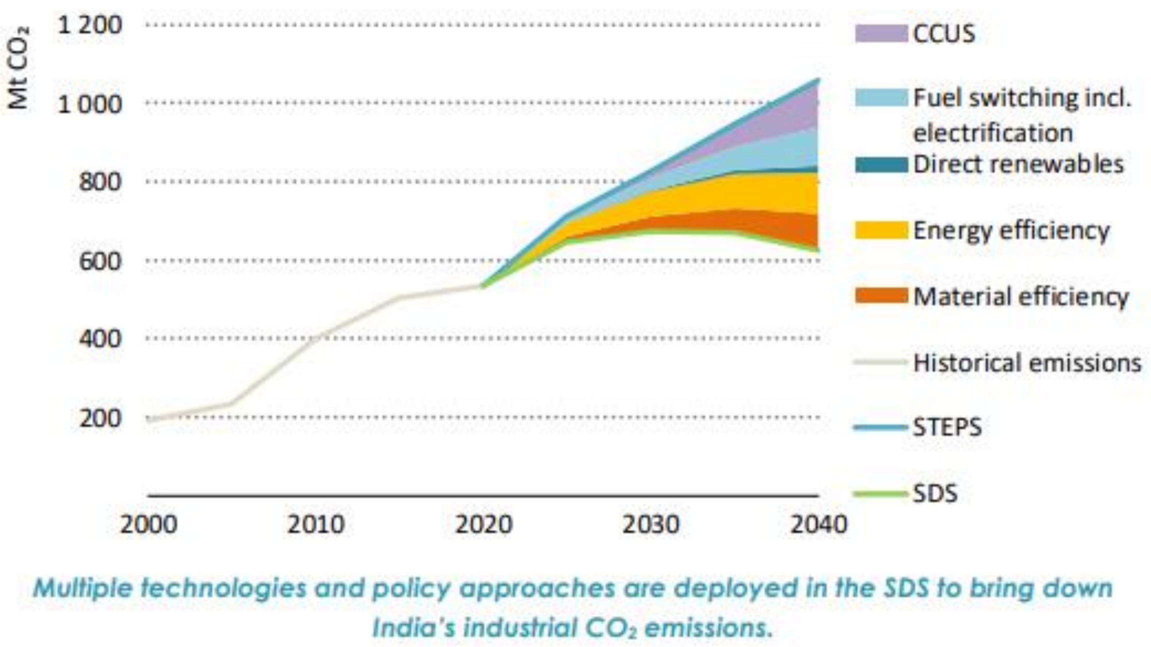
[22] CCUS Projects Explorer – Data Tools - IEA

10.2. CCUS Indian Scenario

A recent 2030 roadmap for CCUS within India's oil and gas industry outlines a series of policy suggestions across short, medium, and long-term horizons. It also highlights significant projects related to Enhanced Oil Recovery (EOR) and Enhanced Coal Bed Methane (ECBM) for CO_2 storage.

Anticipating the capture of 125 million metric tons of CO_2 in the industrial sector by 2040, mainly from the iron and steel, cement, and chemical sectors, the successful implementation of large-scale CCUS requires prompt investments in pipeline infrastructure and the provision of financial incentives such as carbon pricing or tax benefits. [23]

Figure 36 Emissions reductions in the industry sector by abatement option



Source: India Energy Outlook 2021

In India, the utilization of CO2 through methods such as methanol, ethanol, and DME offers the potential to lower emissions as their demand is expected to grow.

Production of Methanol

In the fiscal year 2021-2022, the production capacity for methanol was 392 thousand tonnes (KT), compared to its total capacity of 789 thousand tonnes per annum (KTPA), reflecting a capacity utilization rate of 49.7%. This indicates that less than half of the available capacity was utilized during that period. Moreover, India's methanol consumption reached 2772 KT, highlighting its significant reliance on imports to meet demand.

[23] India Energy Outlook 2021 (windows.net)

Table 19 Market potential for Methanol

Market potential across applications for Methanol (KT)			
Attribute	**2021-22**	**2029-30**	**2035-36**
Existing Applications	2772	5515	8619
Direct use as a fuel	0	42	4745
Production of DME	0	8902	39271
Total Demand	**2772**	**14459**	**52635**

Production of Ethanol

In the fiscal year 2021-2022, the installed capacity for ethanol production stood at approximately 6 million metric tonnes per annum (MMTPA), with actual production reaching around 4.6 MMTPA. India continues to be a net importer of ethanol, importing roughly 489 thousand tonnes (KT) during the same fiscal year. Ethanol production in the country primarily relies on molasses and grains as feedstock.

Table 20 Market potential across applications for Ethanol

Market potential across applications for Ethanol (KT)			
Attribute	**2021-22**	**2029-30**	**2035-36**
Perfumery Grade	136	234	330
Pharma Grade	265	477	721
Food Grade	910	1554	2092
ENA	122	292	522
Fuel Grade	3080	8423	10057
Rectified Spirit	582	1062	1484
Total Demand	5095	12042	15206

Production of DME

Currently, India lacks any domestic capacity for Dimethyl Ether (DME) production, resulting in the entire demand being satisfied through imports. Trade data indicates that the total consumption of DME in India amounted to approximately 1 thousand tonnes (KT) during the fiscal year 2021-2022. This underscores the country's complete reliance on imported DME to fulfill its requirements.

Market potential across applications for DME (KT)			
Attribute	2021-22	2029-30	2035-36
Existing Applications	1	2.1	3.22
Fuel Applications (Blending component with LPG&HSD)	0	6356	28051
Total Demand	1	6358	28054

10.3. About Carbon Capture, Utilization & Storage

Carbon Capture : Carbon dioxide (CO_2) capture technologies extracts carbon dioxide from gas streams which are released from industrial processes like power

Figure 37 CCUS Technologies

1. Chemical Absorption

- Air Liquide – Amine
- Aker Carbon Capture- Proprietary Amine
- Axens DMX Process
- Carbon Clean – Cyclone CC Process
- UOP Amine Guard FS
- Shell CANSOLV and ADIP Ultra Process
- Baker Hughes Chilled Ammonia Process (CAP) and Mixed Salt Process (MSP)
- Linde OASE Blue Technology
- ION Proprietary Amine- Organic Solvent
- Kansai Mitsubishi (KMCDR)'s - Amine

Cryogenic

- Air Liquide – Cryocap FG
- UOP's Ortloff Dual Refrigerant CO_2 Fractionation (DRCF)
- Linde CO_2 liquefaction

3. Adsorption

- Shell Solid Sorbent Technology –TSA (SST)
- Svante Veloxotherm TSA
- Linde HISORP CC

4. Physical Absorption

- Honeywell Selexol

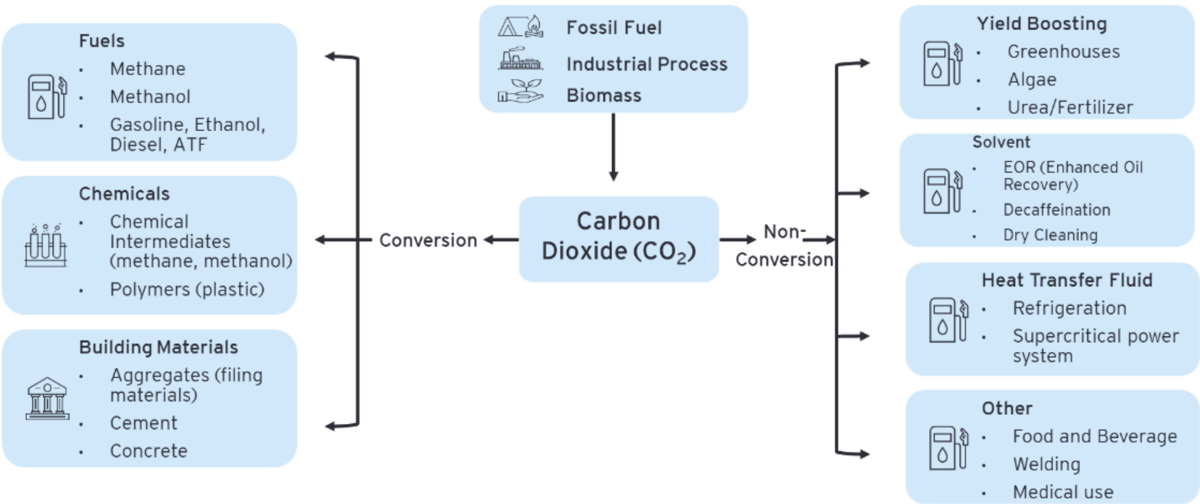
5. Direct Air Capture

- Carbon Engineering
- Climeworks
- Decarbontek LLC

plants, chemical production, cement production or steel making. These techniques fall into three main categories- Solvent-based absorption, Adsorption, Cryogenic separation, and Direct air capture. Below are the technologies available for CCUS[24]:

Carbon Utilisation : CO2 utilization repurposes a GHG gas into a valuable resource fostering sustainable innovation across industries. CO2 can undergo Chemical conversions to produce Methanol, Ethanol, etc. Additionally, it finds application in EOR contributing to environmentally sustainable and economically viable residual oil extraction. There are multiple ways to Utilize CO_2 :

Figure 38 CO2 Utilisation



Many Companies are strategically adopting commercial CO_2 utilization technologies to simultaneously cut emissions and foster economic growth. Below are a few examples companies following CO2 utilization:

Table 21 Technology providers for CCUS

Product	Sub-Category	Project and Location	Technology Provider	Production Capacity	Quantity of CO2 Utilized
Building Materials	Concrete	San Francisco Bay Aggregates LLC, USA	Blue Planet	33 KTPA	14 KTPA
	Concrete	Thomas Concrete, USA	CarbonCure Technologies	1.8 million yd3	4500 TPA

[24] State-of-the-Art-CCS-Technologies-2022.pdf (globalccsinstitute.com)

	Construction Aggregate	AVR's Energy from waste plant, Duiven, Netherlands	Carbon8 Systems	100 tons of building product	-
	Concrete bricks	Ghent Footpath Construction, Belgium	Carbstone Innovation	Unknown	1 m3 of bricks stores 350 kg CO2
Chemicals	Methanol	Shunli CO2 -to-Methanol plant, China	Carbon Recycling International (CRI)	110 KTPA	150 KTPA
	Methanol	George Olah Renewable Methanol plant, Iceland	Carbon Recycling International (CRI)	4000 TPA	5500 TPA
	Ethanol	Beijing Shougang, LanzaTech, China	LanzaTech	60 KT	100 KT CO2
	Ethanol	Steelanol, ArcelorMittal, Belgium	LanzaTech	80 million litres	~1.5 MTPA CO2
Polymers	Bio-plastics (AirCarbon)	Dell Latitude laptop packaging, Sprint cell phone cases, KI plastic chair components	Newlight	> 23 KTPA	Unknown
	Polyether carbonate	Cardyon mattresses, Germany	Covestro	10 KTPA	Mattresses formed of 20 % CO2

Carbon Storage- The end use of the captured CO_2 can be either utilization or permanent storage. It may be securely stored in subsurface geological formations, including depleted oil and gas reservoirs (for EOR), deep saline aquifers, and basaltic rock formations, offering various sustainable storage options.

Enhanced Oil Recovery (EOR) - Oil recovery techniques can be categorized as primary, secondary, and tertiary recovery techniques. The tertiary techniques of recovery include thermal recovery, gas injection (CO_2 injection), and chemical injection. These help in the production of 30-60% of the original oil in place. [25]

[25] CCUS Report Part I Web Only (indiaenvironmentportal.org.in)

The Below table shows India's Capacity for CO2 EOR[26]:

Table 22 Theoretical CO2 storage potential

Category-I Basins	India's Storage Capacity (MT CO_2)
Krishna-Godavari	658.7
Mumbai	1597.2
Assam-Shelf	667.5
Rajasthan	312.5
Cauvery	99.5
Assam-Arakan	67
Cambay	657.2
Theoretical Capacity	**3402.4**

- **Enhanced Coal Bed Methane Recovery (ECBMR) -** In ECBMR, CO2 is injected into non-mineable coal seams under supercritical conditions. The CO2 injected is accumulated in the coal cleats in a dense gas phase. This CO2 is adsorbed and absorbed in the coal. Since CO2 has a higher affinity for coal than CBM, it pushes the coal bed methane towards production wells, thus enhancing its primary recovery. India has a total theoretical capacity of 3.5 GTCO2 Kim and 3.7 GT CO2 Langmuir.[14]

- **Storage in Deep Saline Aquifers -** Permanent storing of CO2 in deep saline aquifers through four trapping mechanisms: structural, residual, dissolution, and mineral trapping. Deep saline aquifers offer great CO2 storage potential for India. India can theoretically store 291 GT CO2 in Deep Saline aquifers. Due to uncertainty of data, further studies are required to get the actual figures.[27]

Table 23 Theoretical Capacity of Basins for CO2 storage

Basins	Capacity (GT)
Category I	147.9
Category II	112.4
Category III	14.65
Total	**291.1**

- **CO2 Storage in Basalts -** Basaltic rock constitutes divalent cations of Ca, Mg, and Fe. They can react with the CO2 dissolved in water to form stable carbonate minerals and thus can offer a safe CO2 sequestration method for an extended period.

- Deccan basalts and Raajmahal Trap, extensive flood basalts in India. Limited data and nascent research on storage mechanisms in basalts in India result in severe data

[26] CCUS Report_Part I Web Only (indiaenvironmentportal.org.in)
[27] CCUS Report_Part I Web Only (indiaenvironmentportal.org.in)

gaps, while high-level assumptions estimate a theoretical storage potential of 97-252 Gt for India's basaltic area.[14]

Table 24 Theoretical CO2 storage from Basalts

Areas	Low (Gt)	High (Gt)
Deccan Volcanic Province	94	243.5
Rajmahal Traps	3.38	8.77
Total Capacity	**97.38**	**252.27**

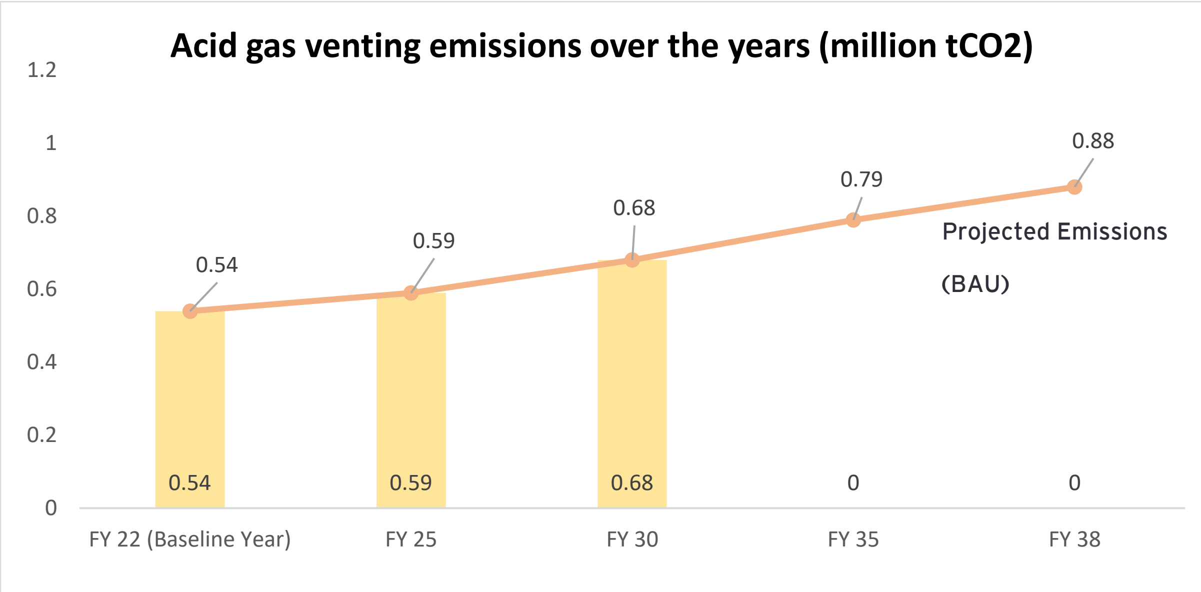
10.4. Emission Reduction Potential for ONGC

CCU Solution

Till FY30, it is assumed that no new initiatives will be deployed. A partnership between ONGC and the fertilizer industry or any other industry can reduce acid gas venting emissions significantly by transporting CO2 via pipeline. The methane in the acid gas needs to be converted to CO2 by retrofitting additional technologies such as flaring.

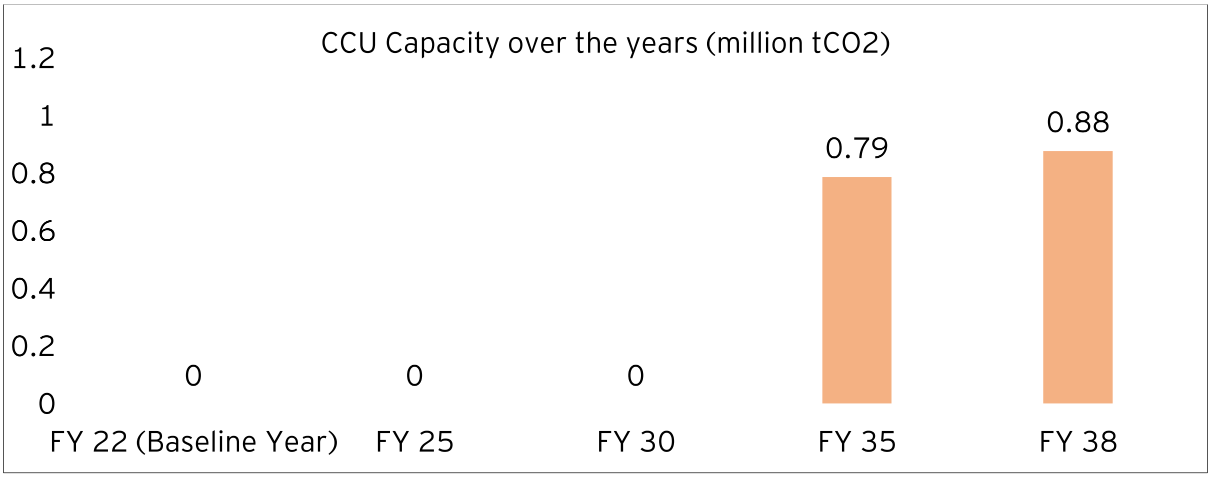
The below graph shows the Acid gas venting emission projection in Business as usually scenario vs the emission projections when ONGC adopts CCU, from baseline year, FY22 to the target year, FY38.

Figure 39 Acid gas venting emission projection



The below graph shows the CCU capacity required till 2038:

Figure 40 CCU capacity required



Cost Analysis of CCU

CCU		
Project Start Year:	2031	FY
Service Duration until 2038:	8	years
Carbon Abatement by 2038:	6.27	Mn tCO_2e
Capital Investment:	120	USD/tCO_2
Total Investment:	62,449	Mn INR
OpEx Share:	3.0%	of CapEx
OpEx escalation Y-o-Y:	5.0%	assumed
Total OpEx by 2038:	17,890	Mn INR
Discount rate for NPV:	10%	assumed
NPV of Total Costs:	70,795	Mn INR

10.5. Case Study

Prominent oil and gas firms are actively engaging in partnerships to deploy or consider CCUS projects as a pivotal step towards emissions reduction:

Chevron

- Chevron has announced to launch a carbon capture and storage (CCS) project aimed at reducing the carbon intensity of its operations in San Joaquin Valley, California.
- Chevron New Energies, and a subsidiary of Enterprise Products Partners announced a framework to study and evaluate opportunities for carbon dioxide (CO2) capture, utilization, and storage (CCUS) from their respective business operations in the US Midcontinent and Gulf Coast.

BP

- BP, ADNOC, and Masdar have collaborated to develop low-carbon hydrogen hubs & decarbonized air corridors between UK & UAE.
- BP and Masdar also looking for opportunities to provide mobility & sustainable solutions to their consumers across UK and UAE. In addition to that BP and ADNOC are working together to decarbonize their existing O&G operations by using Methane and CCUS.

Eni

- Eni participates in the Sleipner project, which is the world's first commercial CO2 storage project (operated by Equinor). At 2020-end, the cumulative amount of CO2 injected since 1996 from the Sleipner West field was about 19mt, out of which 3.3mt is Var Energi's share (about 2.3mt Eni's share)

- With gear on the climate agenda, considerable CCS clusters are being planned and developed across regions

Rotterdam Cluster Project (RCP), Netherlands

Overview

The Rotterdam Climate Initiative supports an integrated CCUS cluster project, ROAD (Rotterdam Opslag en Afvang Demonstratie), aiming to reduce CO2 emissions by 50% by 2030, capturing and transporting CO2 from power plants and industries for offshore storage, with a long-term vision of extending to neighbouring countries.

Carbon Capture

- Initial Capacity: 1.1 mtpa from coal-fired power plant
- 2025 Target: 17.5 mtpa from other parts of the Netherlands and neighboring countries
- Long-term target: 62 mtpa

Transport

- Mode of Transport: Pipeline
- In subsequent phases, other sources would be connected and the offshore pipeline will be modified to transport

Storage

- Storage Option: Depleted gas field located 25 km offshore field (P18 fields reservoir)
- Storage capacity: 42.4 mtpa

Funding

- The Dutch Government will be granting the project consortium (Shell and ExxonMobil) around USD 2.4 billion of funding in form of the subsidies.

Value Propositions

- Favourable Location, Economies of Scale and High-Capacity Utilization

Revenue Streams

- CO2 transit charge collected from the emitters.

Denver City Hub Cluster, USA

The Denver City Hub Cluster in the USA operates a comprehensive carbon capture, transport, and storage system. Utilizing natural CO2 reservoirs as its source, it captures approximately 8.4 million metric tons per annum (mtpa) of CO2 primarily from natural gas processing plants. Transportation of the captured CO2 is efficiently managed through a 160-kilometer supercritical pressure pipeline network. The stored CO2 finds purpose in enhanced oil recovery (EOR) projects, aligning with the storage option exclusively geared towards EOR endeavors. This initiative, supported by both governmental backing and private venture capital, not only addresses environmental concerns but also provides a viable business model. By delivering CO2 to EOR projects at reasonable costs and minimizing CO2 emission taxes, the Denver City Hub Cluster ensures a sustainable revenue stream by receiving payments for the CO2 delivered for EOR from the emitters.

11. Zero Routine Flaring

11.1. Context Setting

Non-emergency flaring and venting occur when oil field operators opt to burn the "associated" gas that accompanies oil production, or simply release it to the atmosphere, rather than to build the equipment and pipelines to capture it. Flaring results in the release of substantial volumes of potent GHGs, including methane, black soot and nitrous oxide.

Around 140 bcm of natural gas is flared globally each year. This is a major source of CO_2 emissions, methane and black soot, and is damaging to health. In 2022, the volume of gas flared worldwide fell by around 5 billion cubic meters (bcm) to 139 bcm (about 3% reduction). Flaring resulted in 500 Mt CO_2 equivalent annual GHG emissions in 2022. Around 70% of gas flared goes to flares that operate on a near continual basis. In the Net Zero Emissions by 2050 (NZE) Scenario, all non-emergency flaring is eliminated globally by 2030, resulting in a 95% reduction in flared volumes and avoiding 365 Mt CO_2-eq. [28]

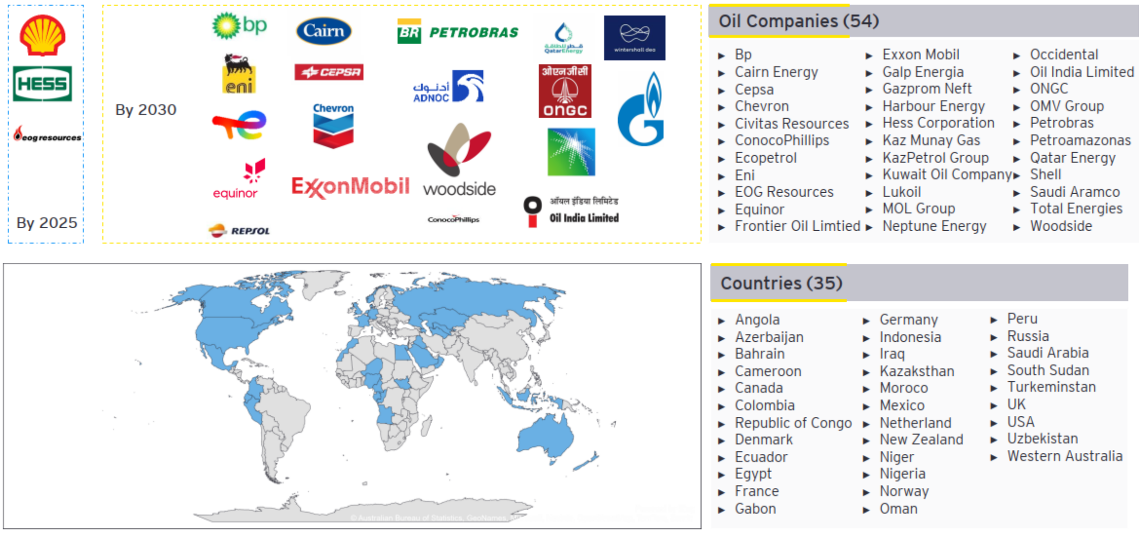
11.2. Global Scenario

Flaring can occur for many reasons, ranging from technical issues (e.g., initial start-up testing of a facility, unplanned equipment malfunctions, etc.) to market factors (e.g. insufficient demand, low gas prices, etc.). As a primary energy source in a world of consistently growing energy demand, associated gas has intrinsic value. Whether as pipeline-quality natural gas or some other derivative product, the market value of associated gas depends on a number of factors that arise along the value chain between the producer and the consumer. However, sometimes the market value does not support a positive return on the investment needed to bring the associated gas from the producing field to a value-added consumptive use. In such cases, and even after considering the societal benefits of utilizing associated gas, routine flaring is often the outcome.

Routine flaring of gas at oil production facilities is flaring that takes place during normal oil production operations in the absence of sufficient facilities or amenable geology to allow the produced gas to be reinjected, utilized on-site, or dispatched to a market. Routine flaring does not include safety flaring, even when it is continuous.

[28] Gas Flaring - Energy System - IEA

Figure 41 Zero routine flaring targets



Source: ZRF-Initiative-text-list-map-104.pdf (worldbank.org)

A number of countries have introduced policies to reduce flaring

- Norway, which was one of the first countries to introduce regulations requiring operators to meter gas and taxing flaring-related CO2 emissions. These policies have been effective, and Norway has reduced flaring emissions by more than 80% since the mid-1990s.
- Colombia cut its flaring intensity by around half between 2015 and 2021 and has reduced flared volumes by 70% since 2012. This stems from the country's focus on emission reductions, creation and empowerment of the National Hydrocarbon Agency (Agencia National de Hidrocarburos [ANH]), Ecopetrol's progress on emission reductions and overall redirection of gas volumes towards the domestic market.
- In the United States, while further regulation and more stringent enforcement across more producer states is needed, regulators in Colorado and New Mexico have joined Alaska in introducing a ban on routine flaring. Around one-fifth of US oil production now occurs in states with a routine flaring ban. [29]

Several international initiatives have been launched to reduce methane emissions from flaring. The Global Gas Flaring Reduction Partnership is a public-private initiative made up of national and international oil companies, national and regional governments, and international institutions. The partnership aims to increase the use of natural gas associated with oil production by helping to remove technical and regulatory barriers to flaring reduction, conducting research, disseminating best practices and developing country-specific gas flaring reduction programmes. Various energy companies, governments and institutions have endorsed the Zero Routine Flaring by 2030 initiative launched by the World Bank and the United Nations in 2015. For new fields, this scheme encourages operators to develop plans to use or conserve all the field's associated gas without nonemergency flaring.

[29] Gas Flaring - Energy System - IEA

For existing fields, operators are asked to eliminate nonemergency flaring as soon as possible, and no later than 2030.[30]

ONGC is a signatory of the Zero Routine Flaring (ZRF) initiative, an initiative established by the World Bank to eliminate routine flaring by 2030. ZRF brings together companies, governments, and institutions together to develop effective mechanisms to combat routine flaring. As a member of ZRF, ONGC has established links with top oil producing corporations and have access to key technological advancements. The coalition allows ONGC to explore the establishment of fresh oil fields that integrate the sustainable management of associated gas, eliminating the need for routine flaring. It also aims to identify economically feasible approaches to eradicate the longstanding flaring practice no later than 2030.

Table 25 Zero routine flaring targets

Oil and Gas Company	Baseline year and value	2021	2022	2025	2028	2030
ONGC	2021-22 (554 MMSCM)					ZRF
bp	Not applicable			Net Zero (US operations)		ZRF
Eni	Not applicable					
Repsol	2018: 344 kt CO2			-50%		
Total Energies	Not applicable			<100m^3/day		
Exxon Mobil	2016: 530 MMSCFD		ZRF (Permian Basin)	-40-50%		ZRF
Chevron	Not applicable				3kgCO2e/boe	ZRF
Devon Energy	2019: 2.21% produced			<0.5%		ZRF
Saudi Aramco	Not applicable					ZRF
Petrobras	Not applicable					ZRF
EOG	Not applicable			ZRF		
Hess Corporation	Not applicable	7% flaring rate (Bakken wells)		ZRF		

Source: Company reports, press releases, news articles

[30] Gas Flaring - Energy System - IEA

11.3. Some Technological Solutions to achieve Zero routine flaring

There are multiple technological solutions that have been developed to combat gas flaring. The company has explored and can adopt various mechanisms to achieve ZRF's target by 2030 (World Bank). The following technical solutions are available:

1) Gas Recovery

Ejectors serve as a means to efficiently regulate gas pressure to a desired level without resorting to compression methods, which can be costly both in terms of installation and ongoing operation. Compressors often come with higher initial expenses, demand specialized maintenance, and involve the use of expensive spare parts. Ejectors, on the other hand, leverage a high-pressure motive fluid to compress low-pressure gas that might otherwise be flared or vented.

Figure 42 Key features of gas recovery

Particulars	Description
Capacity Range	2 MMSCFD with 7.5 bar discharge pressure. Min size: 0.1 MMSCFD
Modularity	Yes
Applicability	Both offshore and onshore
Technical Readiness Level (TRL)	Mature and Commercial (TRL 7- Field Qualified) More than 100 deployment cases

Source : GPA-Kuwait-Final-Paper-2016.pdf (hubspotusercontent10.net); World Bank Document

2) Gas Processing

Gas processing equipment separates NGLs from AG, producing ethane, LPG, C5+, and lean natural gas streams, with propane and butane separated via fractionation; ethane, LPG, and C5+ stored and sold, while natural gas can be utilized or sold in the market.

3) Power Generation

Using associated gas as a field fuel source is cost-effective, enables remote operations without grid connection, and can be utilized through technologies like reciprocating engines and gas turbines that accommodate compositional variability.

4) Compressed Natural Gas (CNG)

1. Production: CNG Production consists of pre-treatment and compression of gas. It aids in the removal of heavy hydrocarbon, removal of contaminants and dehydration.

2. Transportation: Within transportation there are different modes for onshore CNG and marine CNG. As marine CNG is dependent on economic viability, its

transportation varies case by case. Whereas Onshore CNG can be transported through virtual pipeline and mobile CNG filling stations.

5) Mini LNG (Liquified Natural Gas)

Small-scale LNG technologies play a pivotal role in liquefying gas for economically viable transport to markets, particularly when dealing with volumes exceeding 5 MMSCFD. Its energy density, measuring approximately 22 MJ per litre, surpasses that of CNG by a factor of 2.5 and outpaces natural gas at atmospheric pressure by more than 600 times. The liquefaction process is executed at dedicated LNG plants. Subsequently, upon reaching consumers, LNG can be re-gasified, essentially converting it back into natural gas, either at specialized terminals known as regasification plants or terminals, or it can be employed directly as LNG, such as in the case of truck fuel.

6) Mini GTL (Gas to Liquids)

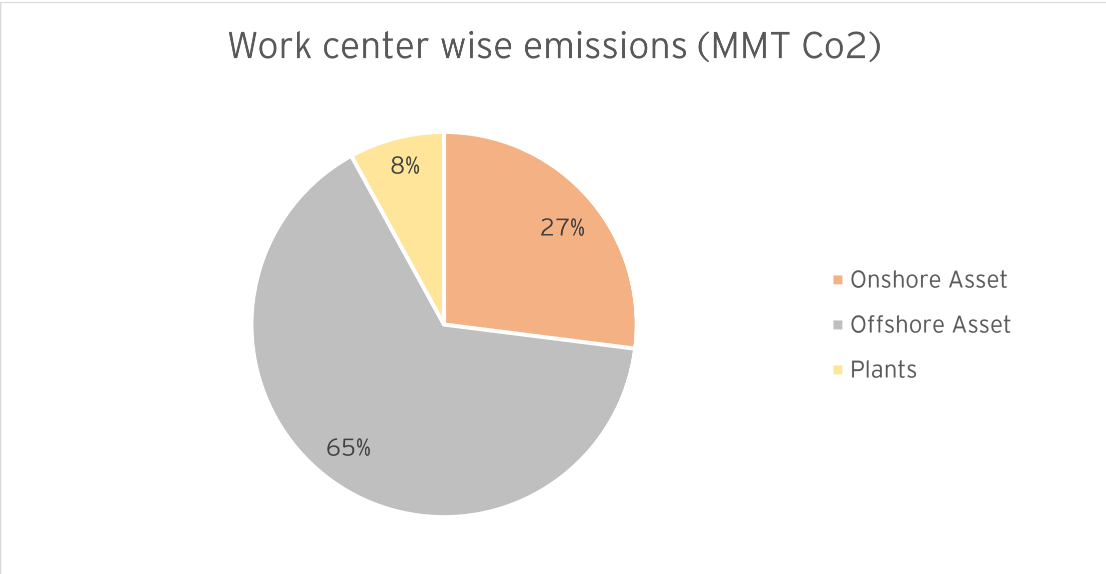
Recent advancements in modular GTL technologies have made small-scale GTL plants (>=10MMscfd of gas), highly flexible mini-GTL units (>= 1MMscfd of gas), and remotely controlled micro-GTL machines (<=1MMscfd of gas) economically viable and operationally feasible.

11.4. ONGC Overview for Flaring

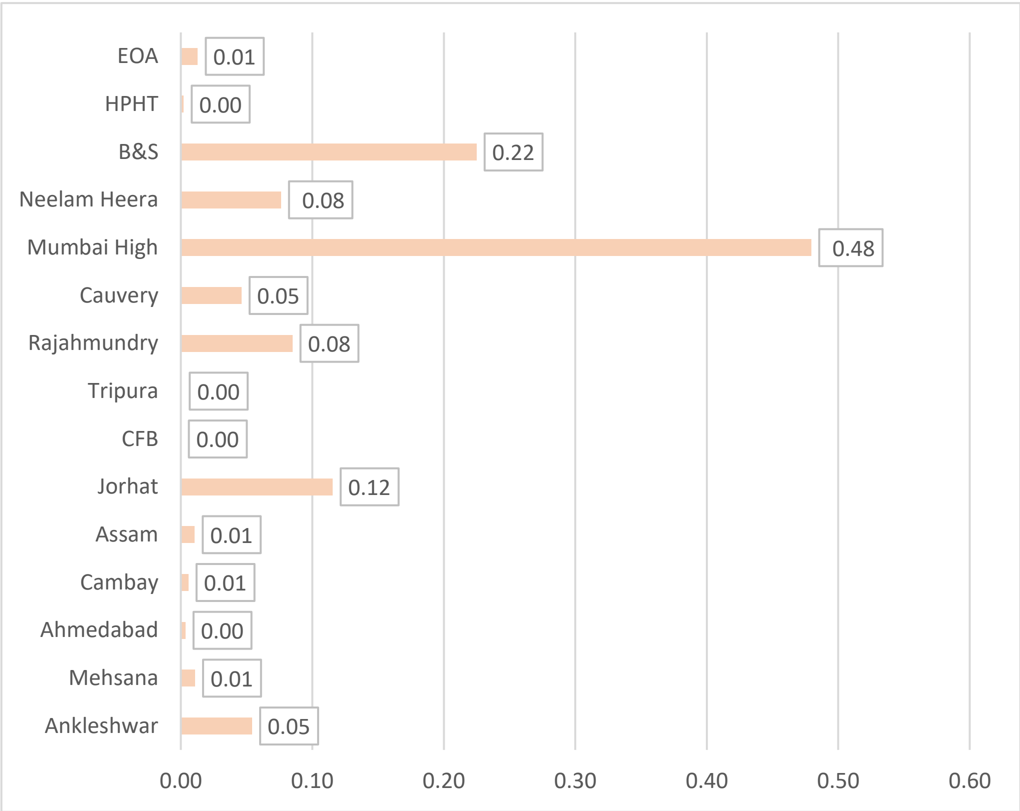
Total Flaring emissions in FY 22 is 1.22 (~14%) million tons of CO2e: - Offshore assets contribute to the highest flaring emissions at 0.8 million tons of CO2e, followed by onshore assets (0.33) and plants (0.09).

Offshore & Onshore Assets contribute to ~92% of the total flaring emissions: - Mumbai-High offshore asset contributes to the highest flaring emissions at 0.48 million tons CO2e, followed by B&S (0.22) and Jorhat (0.12).

Figure 43 Work centre wise emissions

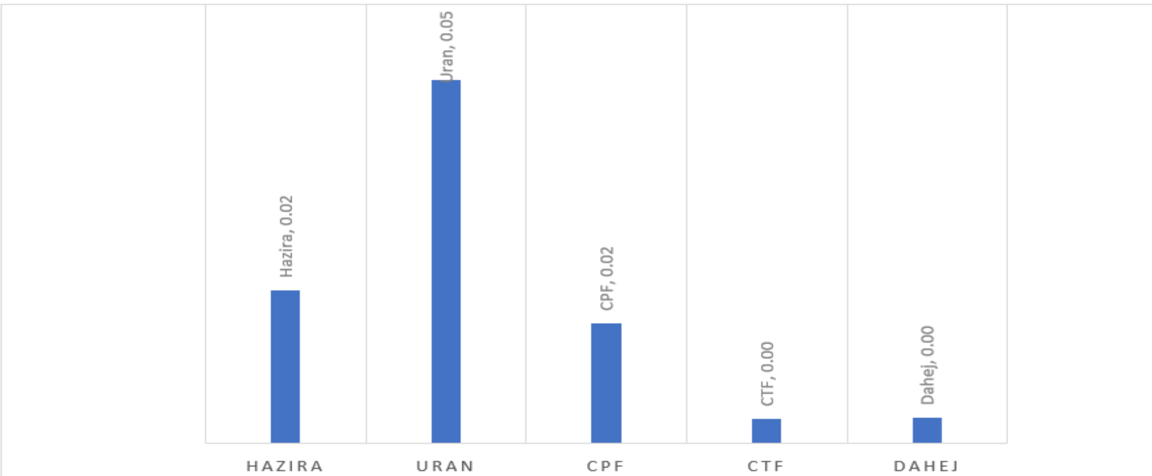


Asset-wise emissions (MMT CO2e)



Plants contribute to ~8% of the total flaring emissions: - Uran plant contributes to the highest flaring emissions at 0.05 million tons of CO2e, followed by Hazira and CPF at 0.02 million tons CO2e.

Figure 44 Plant-wise emissions (MMT CO2e)

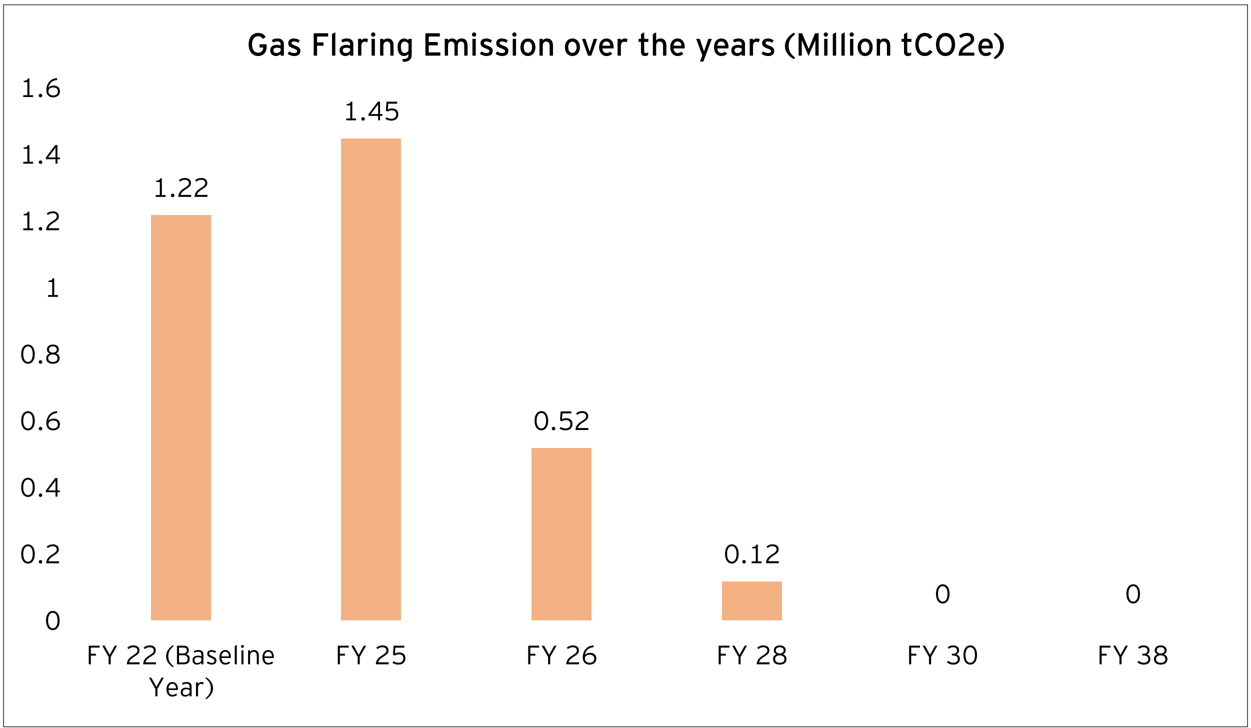


Plant-wise emissions (MMT CO2e)

11.5. Emission Reduction Potential for ONGC

Zero routine flaring stands as a key element within ONGC's decarbonization roadmap, showcasing their commitment to sustainable energy practices. The emission reduction project is scheduled to take one year for implementation, with the reduction in emissions becoming apparent starting from the fiscal year (FY) 2026. To address the significant gas flaring attributed to offshore assets, the plan is to prioritize the deployment of new technological solutions in these assets by FY 2025. During FY 27, the focus will shift to implementing various technological remedies in onshore assets. This endeavour aims to achieve emission reduction starting in FY 2028, aimed at minimizing flaring. With a strategic outlook, the objective is to progressively decrease flaring emissions from plants, starting from FY 2029. By adhering to this trajectory, ONGC anticipates realizing its ambitious goal of achieving Zero Routine Flaring by the year 2030.

Figure 45 Projected Gas Flaring Emissions over the years



Costing of Project mentioned in Annexure 6

11.6. Work centre wise Marginal Abatement Cost Curve (Solution)

The MAC Curve analysis assists in the quality of decisions regarding prioritization and scheduling the proposed abatement measures.

Findings from MAC Curves:

All negative abatement costs correspond to opportunities to reduce emissions with a net economic gain.

- **CNG technologies** offer the highest abatement savings and significant emission reduction
- **Mini LNG, GPP and gas engines** technologies demonstrate moderate abatement savings, presenting viable options for emission reduction
- **Mini GTL using the direct method, and microturbine** show less favorable abatement cost savings.

Figure 46 Mumbai High Asset

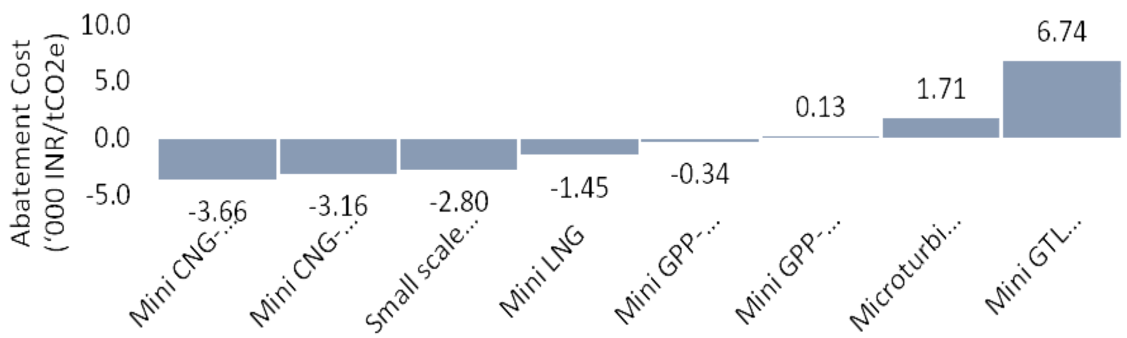


Figure 47 B&S and Jorhat Asset

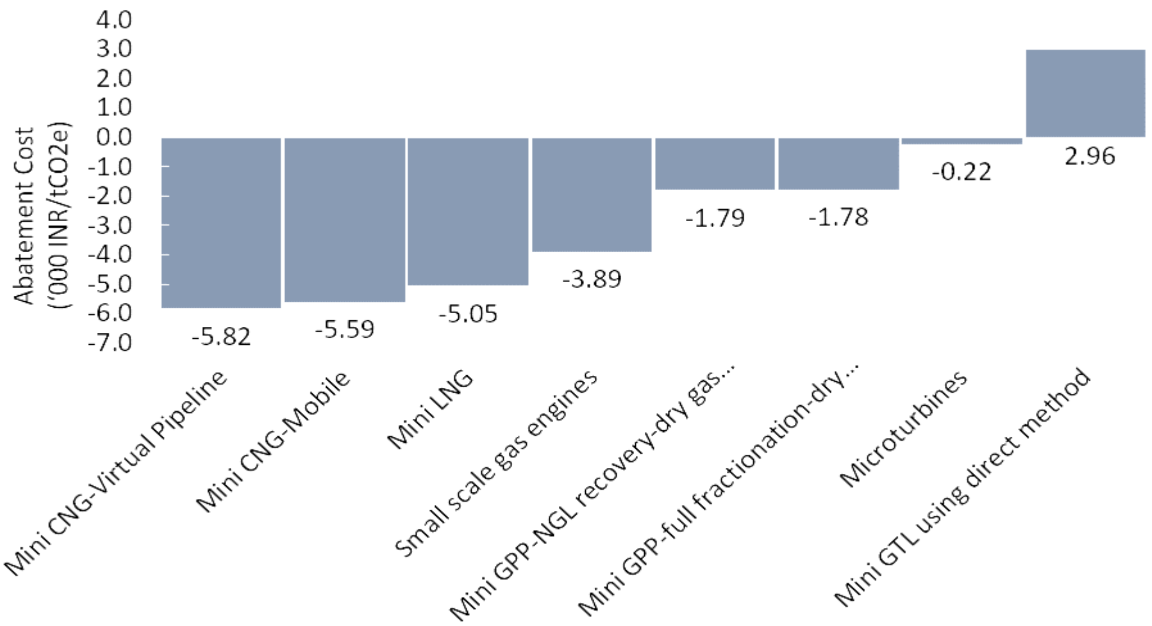


Figure 48 Rajahmundry and Heera Asset

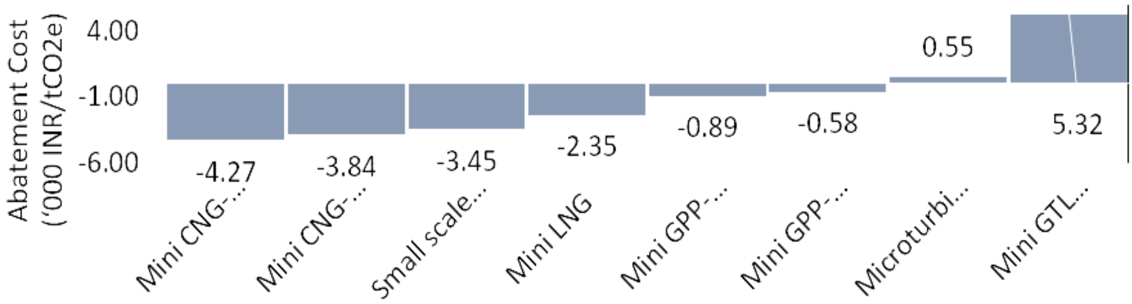


Figure 49 Ankleshwar, Uran and Cauvery

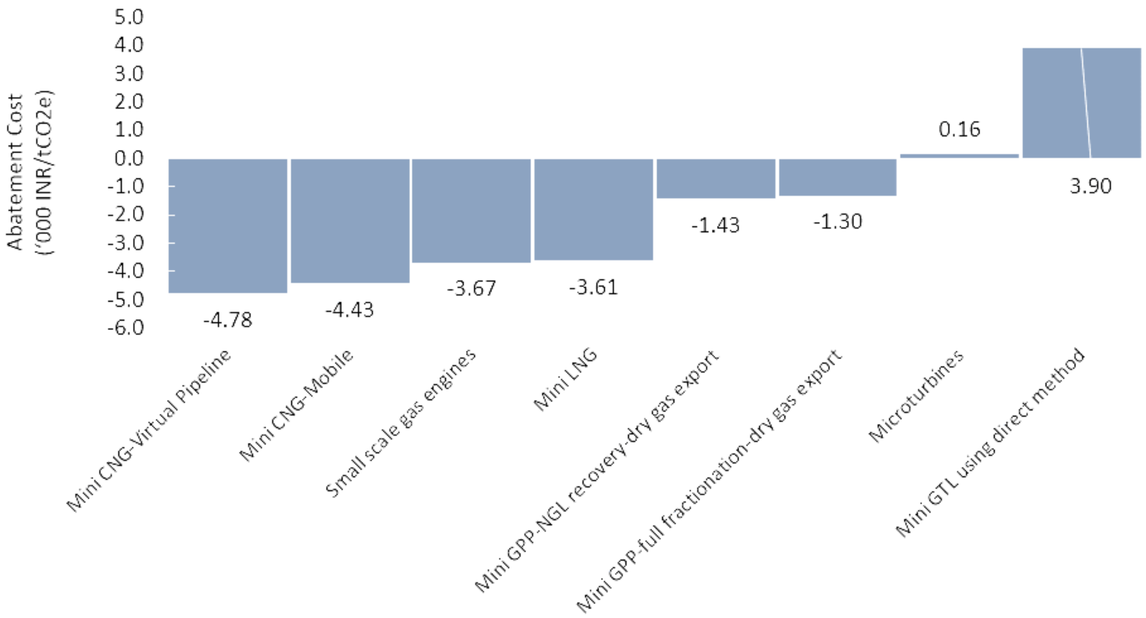
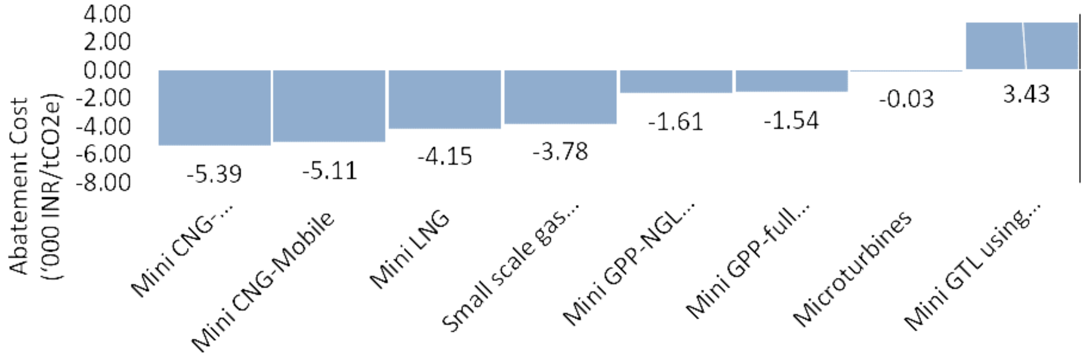


Figure 50 Hazira, CPF, EOA, Mehsana, Assam, Cambay and others



Key Findings

- All negative abatement costs correspond to opportunities to reduce emissions with a net economic gain.
- CNG technologies offer the highest abatement savings and significant emission reduction
- Mini LNG, GPP (NGL recovery), and gas engines technologies demonstrate moderate abatement savings, presenting viable options for emission reduction
- Mini GTL using the direct method, microturbines, Mini GPP (full fractionation) show less favourable abatement cost savings.

11.7. Case Studies

Eni Congo: Gas-to-Power project

Eni's comprehensive approach to flaring reduction includes access to energy, complying with regulations, and collaborating with resource owners, while actively identifying flare reduction and gas monetization projects as an endorser of the 'Zero Routine Flaring by 2030' initiative.

Project description

- 1.98 million cubic meters of associated gas per day
- Capex: USD 300 million
- M'Boundi Gas Gathering: Transport recovered gas to the power plant.
- CED repowering: Existing CED Power plant capacity was doubled to 50 MW via the installation of gas turbine.
- CEC Construction: Development of a new 300 MW power plant in 2010 and an additional 170 MW in 2020
- Gas reinjection program: Reinject excess gas while optimizing reserve recovery from oilfield

Outcome

- Achieved zero routine flaring in the M'Boundi field area
- Associated gas was fully monetized through a program of gas injection and long-term supply contract to the power plant
- Part of Eni's strategic objective to reduce its gas flaring worldwide by 80% by 2015 wr.t 2007 b
- Created social value, environmental benefits, and economic development of the country
- Ensuring access to affordable, reliable, sustainable, and modern energy for the residents of the country

Petronas: Flaring Reduction Project

PETRONAS has implemented novel, low-cost surface jet pump (SJP) technology to recover flare gas, where the use of a conventional booster compressor had been commercially challenging due to limited deck space.

Project description

- The project involved multiple offshore wells producing oil with total gas throughput was 5–7 million scf/day, with variations of up to 25%.
- Replacing conventional booster compressor with SJP.
- CAPEX: <USD 1 million

Outcomes

- It achieved a 100% reduction in flaring.
- Recycling of gas: Nearly all (99%) of the gas captured by the SJP is recycled back to main gas compressor suction from where it is then sent off-site as pipeline quality gas for sale to third parties. The remainder is used as fuel to provide field power.
- Minimal maintenance cost.
- SJP technology can be both a low-cost and high-reliability solution.

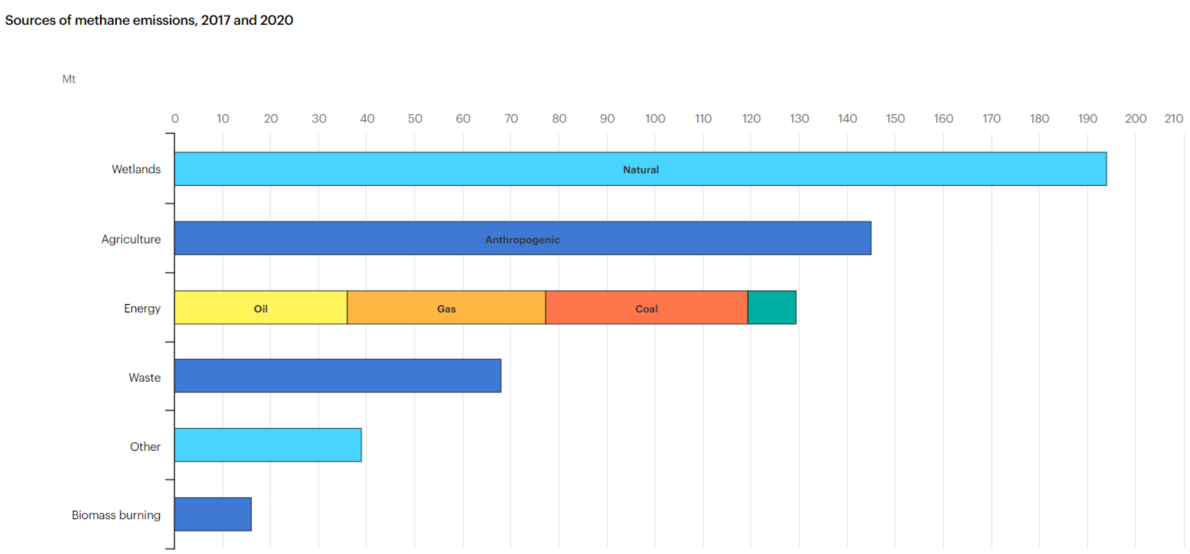
12. Methane Reduction

12.1. Premise

The concentration of methane in the atmosphere is currently around two-and-a-half times greater than pre-industrial levels and is increasing steadily. This rise has important implications for climate change. Estimates of methane emissions are subject to a high degree of uncertainty, but the most recent comprehensive estimate – provided in the Global Methane Budget – suggests that annual global methane emissions are around 570 Mt. This includes emissions from natural sources (around 40% of emissions) and those originating from human activity (the remaining 60%, known as anthropogenic emissions).

The Global Methane Budget synthesizes results from top-down studies and bottom-up estimates to provide global figures for methane emissions from 2008 to 2017. The largest source of anthropogenic methane emissions is agriculture, responsible for around one quarter of emissions, closely followed by the energy sector, which includes emissions from coal, oil, natural gas and biofuels.[31]

Figure 51 Sources of methane emissions

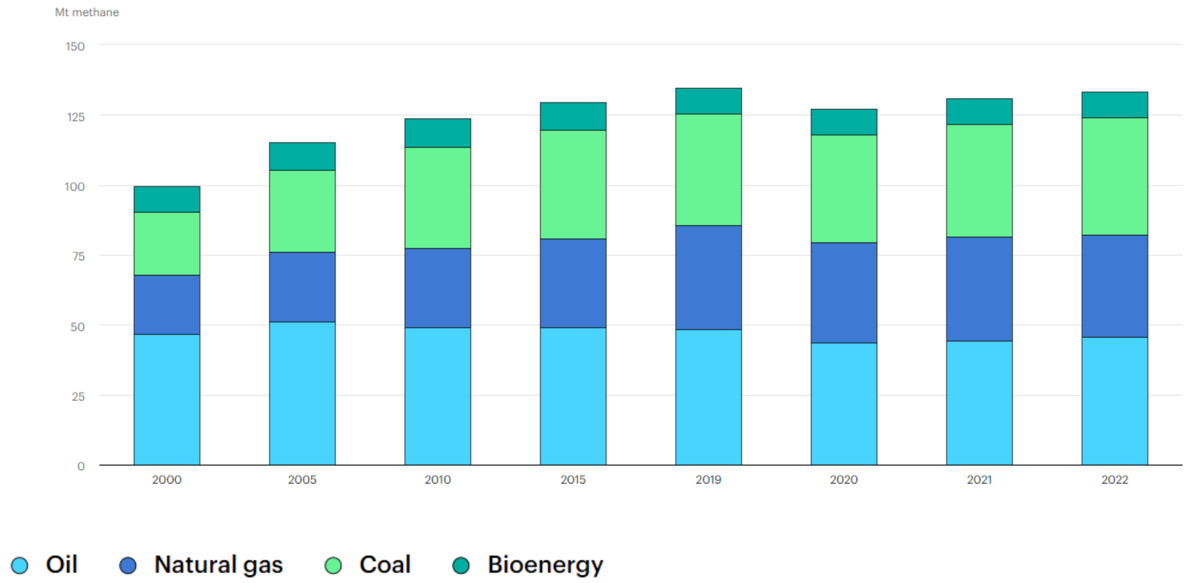


Methane emissions from the global energy sector

It is estimated that the global energy sector was responsible for nearly 135 million tonnes of methane emissions in 2022, a slight rise from the amount in 2021. Coal, oil and natural gas operations are each responsible for around 40 Mt of emissions and nearly 5 Mt of leaks from end-use equipment. Around 10 Mt of emissions comes from the incomplete combustion of bioenergy, largely from the traditional use of biomass. The energy sector is responsible for nearly 40% of total methane emissions attributable to human activity, second only to agriculture.[32]

[31] https://www.iea.org/reports/methane-tracker-2021/methane-and-climate-change
[32] Overview – Global Methane Tracker 2023 – Analysis - IEA

Figure 52 Global methane emissions from energy sector



Source : International Energy Agency

12.2. Context Setting

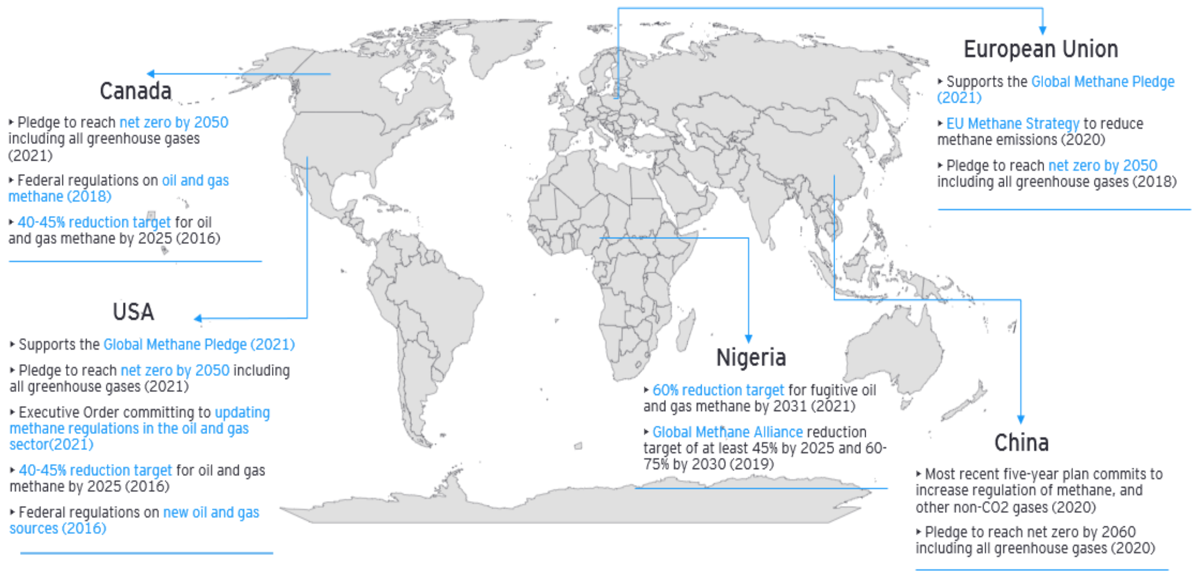
At COP26, more than 150 nations committed to the Global Methane Pledge (GMP), a collective effort to lower worldwide methane emissions by 30% from 2020 levels in all industries by 2030. This reduction in methane has the potential to reduce global warming by 0.2 degrees Celsius by 2050, mitigating the intensity and occurrence of climate change-induced extreme weather events.[33] Since its launch, GMP has generated unprecedented momentum for methane action. Over 150 countries have now endorsed the GMP, with over 50 nations developing national methane action plans. Significant financial support is also channeled toward methane reduction efforts, and collaborative initiatives and policies are launched to drive down methane emissions in critical sectors.[34]

Figure 53 Background

[33] Homepage | Global Methane Pledge
[34] Global Methane Pledge: From Moment to Momentum - United States Department of State

Policy commitments and actions on methane emissions from fossil fuel operations:

Policy and regulation play an important role in ensuring that companies have incentives to undertake abatement action. Below are actions taken by a few counties to reduce the emissions:



Below are the targets set by Oil and gas companies for methane reduction:

AE: Absolute Emissions
MI: Methane Intensity (methane emissions/gas sold) in %

Oil and Gas Company	Baseline year and value	2021	2025	2028	2030	2050
British Petroleum (BP)	MI (2019): 0.14%	-	0.2%	-	-	-50%
Eni	AE (2014): 116 ktCH4	-	-80%	-	-	-
	MI: NA	-	0.25%	-	-	-
Repsol	MI (2017): 1.34%	-	0.2%	-	-	-
Total Energies	AE (2020): 64 ktCH4	-	-50%	-	-80%	-
	MI: NA	-	Far below 0.2%	-	<0.1%	-
Exxon Mobil	AE (2016): 8 million tCO2e	-	-40-50%	-	-	-
	MI (2016): 0.07	-40-50%	-	-	-70-80%	-
Chevron	MI (2016): 4.5 kg CO2e/boe	-	-	-53%	-	-
ConocoPhillips	MI (2019): 3kg CO2e/boe	-	-0.1	-	-	-
Petrobras	MI (2015): 0.65 tCH4/tHC	-	0.39 (-40%)	-	-	-
Occidental	MI: NA	-	<0.25%	-	-	-
Devon Energy	MI (2019): 3.65 tCO2e/kboe	-	-	-	-65%	-
EOG Resource	MI (2019): 0.12%	-	0.06%	-	-	-
Hess Corporation	MI (2017): 0.4%	-	0.19% (>-50%)	-	-	-
Pioneer Natural Resources	MI (2019): 4.4 kg CO2e/tboe	-	-	-	-0.75	-

12.3. Emission Sources

Emission Sources from Oil and Gas upstream industry include methane emissions from exploration to transportation like venting, fugitive, and incomplete flaring from end-to-end operations. Below are some of the Methane emission sources [26]:

- Large Tanks with flares/without control/with Vapour Recovery Units,
- Heaters,
- Boilers,

- Pneumatic Devices,
- Vessel Blowdowns,
- Gas Venting,
- Gas Flaring,
- Glycol Dehydrator,
- Hydraulic Fracturing Completion & Workover that vent,
- Kimray Pumps,
- Dehydrator,
- Gas Engines/Compressor Start/ Reciprocating Compressor

12.4. Abatement Options

Possible Abatement options for minimizing venting, fugitive, and incomplete flaring from end-to-end operations are[26]:

Leak detection and repair (LDAR) programs are the key mechanism to mitigate fugitive emissions from the production, transmission, or distribution segments of the value chain. Apart from LDAR, other abatement options are Blowdown Capture and Route to Fuel System, Early replacement of intermittent-bleed devices with low-bleed devices, Early replacement of high-bleed devices with low-bleed devices, Install New Methane Reducing Catalyst in Engine, Install Flares, Install Non Mechanical Vapor Recovery Unit, Install Plunger Lift Systems in Gas Wells, Install Vapor Recovery Units, Replace Kimray Pumps with Electric Pumps, Redesign Blowdown Systems and Alter ESD Practices, Replace Pneumatic Chemical Injection Pumps with Electric Pumps, Route to existing flare - Large Dehydrators, etc.

Below are some of the technologies owned by the peers to curb emissions:

Figure 54 Technologies for methane reduction

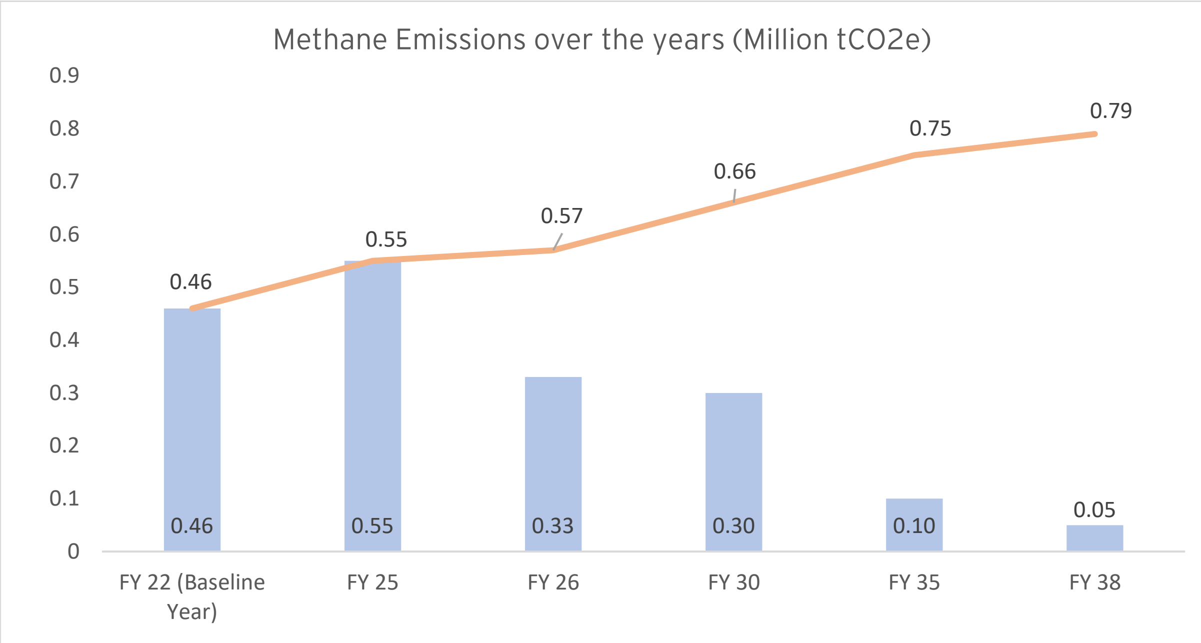
Customer/ Owner	Name of Technology	Technology Description	Owner of Technology
Shell	Claire and Iris Satellite	‣ In 2016, Claire, the first high-resolution satellite was launched with the capability of measuring GHG emissions from any industrial facility ‣ In 2020, Iris was launched which is 100 times more powerful than Claire	GHGCast
Shell	Drone-Monitoring Services	‣ Leverages the drone technology's optical gas-imaging camera and laser-based detection system to support its methane-leak detection and repair program	SENSIT Technologies
PG&E Pacific Gas and Electric Company	Fixed Point Laser (FPL) and Open Path Laser Sensor	‣ FPL uses a Tunable Diode Laser Absorption Spectroscopy (TDLAS) technology to provide instantaneous and accurate responses to the presence of methane	Honeywell | Rebellion
Honeywell	Gas Cloud Imaging Camera (GCI)	‣ GCI uses a special hyperspectral video camera, a stationary, spectral imaging, video system developed for the detection and quantification of methane leak across the petrochemical value chain	Quanta3
equinor	QM 3000	‣ QM3000 is a methane-specific diode laser system it uses low-cost, low-power, chip-based near-infrared tunable laser diodes used in fiber-optic communications	Avitas

Source : Secondary Research

12.5. Methane Emission Reduction at ONGC

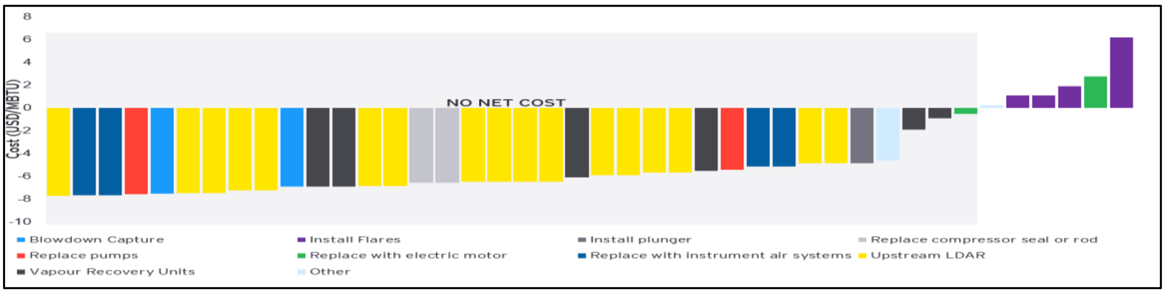
ONGC's total methane emissions in FY 22 is 0.46 million tons of CO_2e. Out of the 0.46 million tons of CO2e, 78% is from Fugitive emissions followed by 22% vented methane emissions.

Projected Methane emissions at ONGC



By harnessing innovative technologies, optimizing operations, and sustainable approaches, ONGC can combat methane emissions to achieve net zero by 2038. The emission reduction project is scheduled to take one year for implementation, with the reduction in emissions becoming apparent starting from the fiscal year (FY) 2026. According to the MAC Curve (Marginal Abatement Cost Curve), approximately 53% of methane emissions can be mitigated at no net cost, resulting in a 53% reduction in emissions by FY 2026. Moreover, as ONGC transitions to electrify its operations, additional methane emissions can be curtailed. Switching to electric motors has the potential to further abate around 73% of emissions.

Figure 55 MACC for Methane reduction



Source: [Marginal abatement cost curve for oil and gas methane emissions by mitigation measure, 2022 – Charts – Data & Statistics - IEA]

ONGC's collaboration with fertilizer industries for CCU technology deployment is anticipated to yield decreasing vented methane emissions from FY 2030 onward. Considering the intrinsic characteristics of oil and gas operations, an IEA analysis assumes that approximately 5% of methane emissions may not be feasible to abate.

12.6. Case Studies

Case 1 - Enagas: Tackling methane emissions in the midstream segment

Overview

Enagás is the main gas infrastructure operator in Spain and the Technical Manager of the Gas System. It has 11,000 km of gas pipelines, 19 compressor stations, 3 underground storage facilities and 4 LNG regasification terminals. Enagás has set ambitious methane reduction targets for 2025 and 2030 (45% by 2025 and 60% by 2030 from 2015 levels) in line with the Global Methane Alliance initiative of the United Nations.
Enagás joined the Oil and Gas Methane Partnership 2.0 framework in 2020 and obtained its "Gold Standard" in 2021. This recognizes the company's commitment to reducing methane emissions as well as the company's efforts to improve the reliability of methane data both for operated and non-operated assets.

Enagas efforts to reduce methane emissions:

1. Annual Leak Detection and Repair Campaigns: Avoided 5624 tonnes of CO2e and reduced fugitive emissions by 11% from 2020 levels
2. Use of boil-off gas compressors in LNG regasification plants
3. Use of electric pumps in all operated facilities.
4. Implementation of a vent gas recovery system at one compressor station, which reduces CO2e by 3500 tonnes per year
5. Progressive substitution of natural gas-driven turbo compressor for electric compressors.
6. Use of in-line compressors, portable compressors/portable flares to avoid vents in special operations.
7. Continued replacement of pneumatic actuators with electric ones.

Monitoring devices used:

1. Carried out top-down measurements based on different technologies to support better inventory data
2. Implementation of a software application for detailed monitoring of venting in the transport network.
3. Invested in SATLANTIS for high-precision optics calibration tests on GEISAT microsatellites to detect and quantify methane emissions
4. Leadership in research projects focused on site-level technologies and emissions measurement.

Outcome

Numerous mitigation measures have been implemented in recent years, enabling a 36% methane emissions reduction from 2015 to 2021.

Case Study 2 – GRT gas: Abating vented emissions in transmission networks.

Overview

GRTgaz is the main gas transmission system operator in France with more than 32,000 km of pipelines to transport gas from suppliers to consumers connected to its network. In 2016, GRTgaz set an ambitious strategic objective of reducing two-thirds of its methane emissions by 2020. GRTgaz successfully achieved this target through leak detection and repairs programs, mobile gas recovery recompression solutions and R&D programs led by the GRTgaz research centre. In 2020, GRTgaz raised this target to a 80% reduction of its methane emissions by 2025 (from the 2016 baseline), representing a decrease of 16.2 kt CH_4 from 2016 to 2025.s

Measures deployed by GRTgaz

GRTgaz reduced venting on its transmission network, to recover or reduce pipeline maintenance vents, compressors vents, and even smaller vents on delivery stations.

Reducing pipeline maintenance vent

GRTgaz's preventive measures during pipeline maintenance saved over 90% of vented gas since 2018.

Technological solutions deployed.

1. Pump, recompress, and reinject gas from a pipe section that will be repaired or maintained, using large recompression mobile units
2. Where recovery is not possible, flaring of the gas through high efficiency systems.

In addition, GRTgaz developed a Quick Booster Access solution which is a mobile gas booster technology that sucks gas from one structure and channel it to a service structure, without releasing it into the atmosphere. This device enables gas pressure reduction by up to 0.5 Bar/hour, and reinjection into the gas system.

Reducing Compressor Vents

In 2020, GRTgaz planned to reduce venting emissions from compressor stations

Technological solutions deployed

1. Elimination of vent leaks (isolation valves)
2. Recompression or use of compressor depressurization gas
3. Mitigate leaks from the compressor seals (nitrogen seals or recovery)
4. Limit automatic depressurization of compressor units related to emergency shutdowns

Outcome

During maintenance works on transmission pipelines, a mix of solutions enabled GRTgaz to save more than 90% of the gas that would otherwise have been vented since 2018.

Case Study 3 - Baker Hughes and bp: Reducing methane slips from flaring-Flare.IQ.

Overview

bp's ambition is to be a net-zero company by 2050. This ambition is supported by 10 aims, including aim 4: "To install methane measurement at all our existing major oil and gas processing sites by 2023, publish the data, and then drive a 50% reduction in methane intensity of our operations". As part of that plan, bp is using Flare.IQ to help better understand, measure, and ultimately reduce methane emissions.

Technology Used

Flare.IQ is an advanced flare control and digital-verification platform developed by Panametrics, a Baker Hughes company. The flare.IQ solution sits on a plant's control system, constantly measuring emissions and providing real-time data so that operators can ensure the flare is running at the targeted 98% destruction and removal efficiency.

Outcome

The data showed consistently high combustion performance standards, often above 99%, consistent with project design.

13. Carbon Offsetting

13.1. Context Setting

Carbon Offsetting will be an important tool to compensate for GHG emissions from ONGC's Scope 1 and 2 specific sources. To align with short-, medium- and long-term goals under the road to Net-Zero, Carbon offsetting will go hand-in-hand with the decarbonization efforts.

Carbon offsetting will essentially involve efforts and investment in voluntary and additional activities either in-house or funding projects (in form of Carbon credits) that projects measurable and verifiable emission reductions, raise awareness and have measurable Sustainable Development impacts (SDGs).

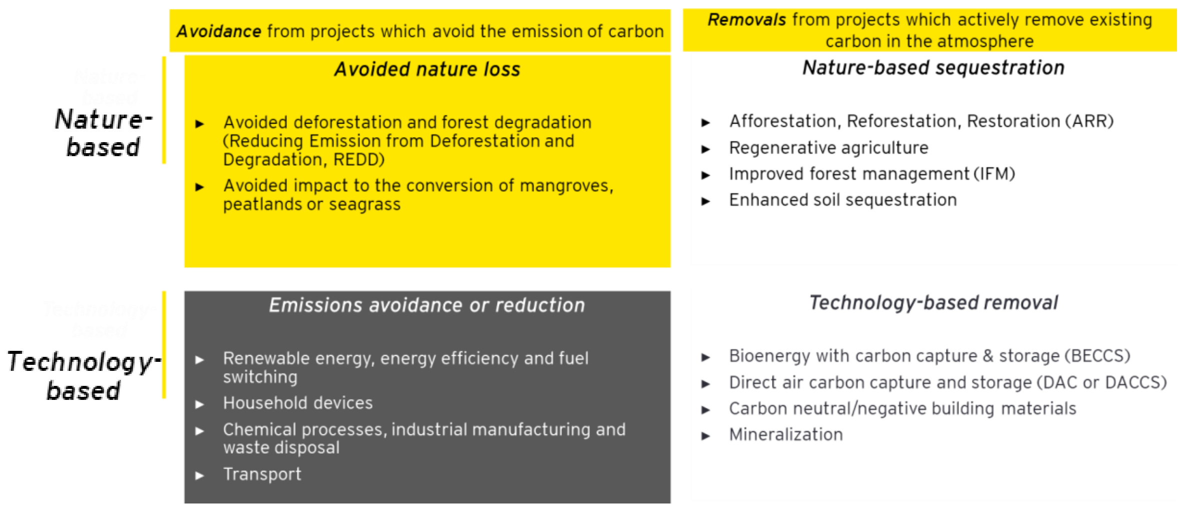
How it works
A carbon offset/credit/allowance is a transferable instrument certified by governments or independent certification bodies that represents the reduction of one metric ton of carbon-dioxide equivalent (CO_2) by a qualifying carbon reduction project. It may or may not represent the actual reduction of carbon emissions.

As per the guidelines, offsetting cannot account more than 5% (Scope 1 & 2) and 10% of overall reductions. *To ensure compatibility with the Paris agreement goals, offsets should be 100% carbon removal by 2050.*

13.2. Carbon Offset Projects

Carbon credits/offset projects can be categorised into avoidance and removal categories which may further be sub-classified as Technology and Nature based solutions.

Figure 56 Nature and Technology based projects



Source: Taskforce on Scaling Voluntary Carbon Markets 2021

ONGC has a well-established track record of carbon offset projects being registered and issuing offsets under UNFCCC's Clean Development Mechanism (CDM). All of previously invested Carbon offset projects are technology based such as Renewable Energy and Energy Efficiency.

Given the recent turn of events in the global and domestic carbon markets, the demand is shifting towards nature-based solutions where the supply is short. Besides emission reduction, nature-based solutions offer multi-dimensional benefits such as ecosystem restoration, community benefits and local economic development. Hence, Nature based solutions are low investment emission sinks with longer crediting period and greater SDG impacts.

Below is listed few project categories under nature-based solutions- carbon offsetting:

Table 26 Nature based solutions: carbon offsetting

NbS Classes	Sub-Categories	ER potential range (tCO_2/ha/year)
Forestry and Land-use	Improved Forest Management (IFM)	0.5 to 3.0
	Agro forestry	1.0 to 4.0
	Afforestation, Reforestation and Revegetation (ARR)	6.0 to 10.0
	Blue Carbon (Mangrove, Seagrass, etc.)	1.5 to 2.5
	Reducing Emissions from Deforestation and Forest Degradation (REDD+)	0.5 to 5.0
	Soil-Carbon	0.09 to 1.5
Agriculture	Sustainable/Regenerative Agriculture	0.5 to 2.0 Integrated projects with multiple interventions may range from 2.5 to 7.0
	Grassland/Rangeland Management	0.15 to 0.5
	Livestock Management	0.5 to 3.5

13.3. Carbon Offset Standards/Certificates

Organizations can also purchase carbon credits which represents a quantifiable reduction of greenhouse gas emissions through investment in projects such as renewable energy installations, reforestation efforts, or methane capture initiatives.

Below table shows various carbon credit certifications/mechanism that can be availed for offsetting purposes:

Table 27 Carbon credit certifications

S. No.	Interventions	Availability	Project Life
1	Gold Standard	Available	Short Term
2	Verra Standard	Available	Short Term
3	Low carbon intensive appliances – Clean Cook Stoves	Available	Long Term
4	Renewable energy (CER)	Available	Long Term
5	Energy Efficiency Mechanisms – LED Distribution	Available	Long Term
6	Small Scale CCUS	Future	Long Term
7	Carbon Removal Technologies	Future	Long Term

13.4. Emission reduction potential for ONGC

Since ONGC has potential for CCS, ONGC can opt for it for offsetting its carbon. Refer Section 15.2

Alternately, we can also opt for NBS etc

ONGC may require offsetting the GHG emissions in phased manner as suggested in the following table based on the roadmap and targeted capacity:

Table 28 Emission reduction potential

S.No	Project	Capacity	$tCO_{2}e$	Target Year	Project Sponsor	Project beneficiary
1	Near Term offset requirement	0.1 million carbon credits/14.5 Million trees	0.1 million	FY 25	Corporate	ONGC
2	Near to Mid-term offset requirement	0.25-0.3 Million carbon credits/36.25-43.5 million trees	0.25-0.3 Million	FY 30	Corporate	ONGC
3	Mid-term offset requirement	0.25-0.3 Million carbon credits/36.25-43.5 million trees	0.25-0.3 Million	FY 35	Corporate	ONGC
4	Long-term offset requirement	0.08-0.18 Million carbon credits/11.6-26.1 million trees	0.08-0.18 Million	FY 38	Corporate	ONGC

14. Internal Carbon Pricing

Carbon pricing involves attaching a cost to greenhouse gas (GHG) emissions for which an organization is accountable, to enable their reduction. Carbon pricing incentivizes companies to optimize their operations, transform their activities or offset their emissions by purchasing carbon credits. There are two types of carbon pricing – external (Carbon Tax, Emissions Trading System) and internal.

Companies can set an internal carbon price (ICP) voluntarily to evaluate the cost of each ton of CO2 equivalent emitted. ICP can be a strategic planning tool to manage climate-related business risks and enable the transition towards low-carbon operations. It can drive investment towards more energy efficiency technologies, enable adoption of technologies by creating a pool of funds, promote R&D of low-carbon products, and make renewable energy competitive with conventional fossil fuels. ICP can further futureproof the business by preparing for future regulatory changes in the form of taxes or ceilings on carbon emissions; and help respond to investor concerns. Thus, ICP can be incorporated into business strategy and drive innovation, investment, and economic growth.

There are several approaches to ICP including Shadow Pricing, Implicit Pricing, Internal Carbon Tax or Fee and Internal Cap and Trade, which are described briefly below:

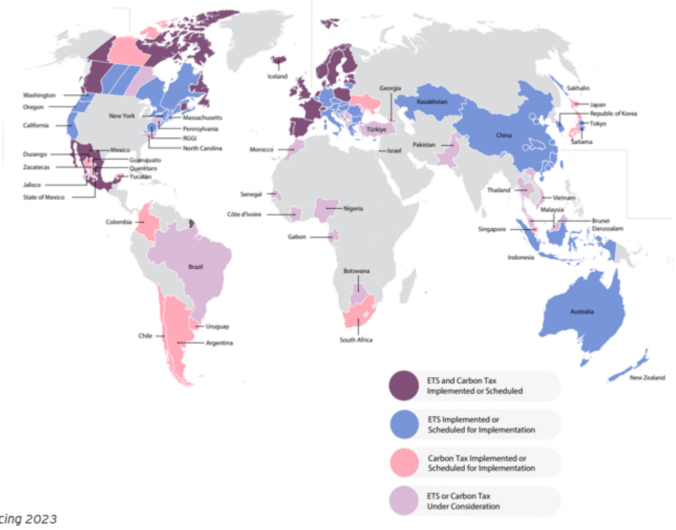
- **Shadow Pricing** – This involves computing an additional carbon value during calculation of Internal Rate of Return (IRR) in investment analysis. This is incorporated into each investment decision and applied to resulting GHG emissions. Assumptions regarding exchange rates or commodity prices remain the same.
- **Implicit Pricing** – This is calculated as the cost of abatement divided by tonnes of CO_2 equivalent abated. Implicit pricing can be used as a benchmark to set an Internal Carbon Price.
- **Internal Carbon Tax/Fee** – This involves adding a carbon cost in relation to the operating expenses. Transfer of funds internally can be done through either internal financing for emission reduction projects, low carbon products & services or R&D, or by purchasing offset credits externally.
- **Internal Cap and Trade** – This involves setting a fixed number of 'allowances' with each equalling 1 metric tonne of CO_2 equivalent. If this cap is exceeded, additional allowances are purchased to offset excess emissions. If emissions fall below the cap, allowances can be sold.

14.1. Trends in Carbon pricing regulation : Global

As of April 2023,

- **73** external carbon pricing mechanisms in operation across different jurisdictions worldwide in the form of:
  - Carbon Taxes
  - Emissions Trading Systems (ETS)
- **72** countries (mostly in the EU and North America) have either implemented, scheduled or are considering Carbon Tax or ETS for external carbon pricing
- **US $61-122 per tCO_2e** is the 2030 Carbon Price Corridor (i.e., a recommended price projection by 2030 to serve as a benchmark for businesses and governments to achieve decarbonization aligned with the Paris Agreement goals)

Map showing adoption trends of Carbon Tax and ETS worldwide



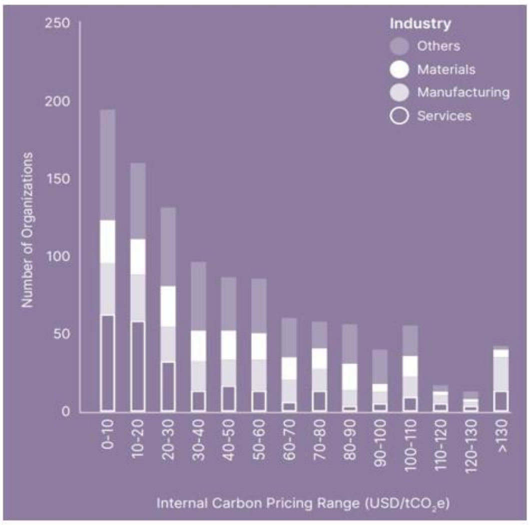
Source: The World Bank Publication: State and Trends of Carbon Pricing 2023

14.2. Trends in ICP : Global

In 2022,

- **Services Industry**, particularly the **Finance industry** has the highest no. of companies having ICP (~25% of total reporting to CDP)
- **Manufacturing Industry** accounts for the second highest no. of companies having ICP
- **Wide variation** in Internal Carbon Prices set by companies (US$ 0.01 - 3,556 per tCO_2), but almost all companies set ICP to less than US$ 130 per tCO_2
- **< US$ 100 per tCO_2** - Internal Carbon Price set by most companies is under US$ 100 per tCO_2. 146 companies (13%) reported setting an ICP above US$ 100 per tCO_2

ICP applied across Industries



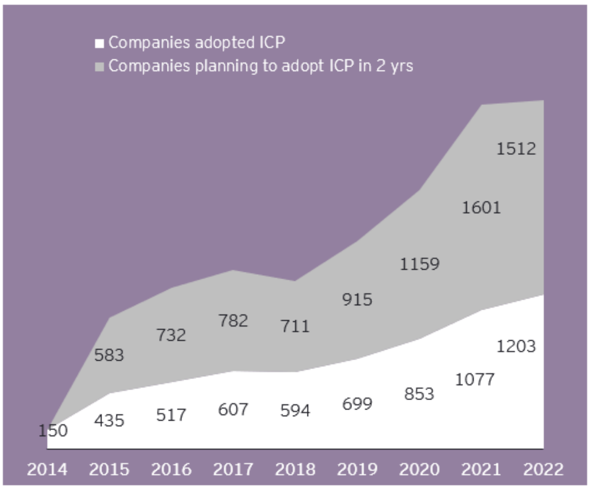
Source:
The World Bank Publication: State and Trends of Carbon Pricing, 2023

CDP is the largest repository of information on corporate exposure to carbon pricing regulations, worldwide.

In 2022,

- **1,203** companies worldwide, reported having an ICP in their CDP Annual Disclosures
- **~1,500** companies worldwide, reported planning to adopt ICP in next 2 years in their CDP Annual Disclosures
- **52%** of companies with ICP already subject to Carbon Tax or ETS, and a **further 15%** expected to be brought under compliance within 3 years
- **Europe and APAC** regions account for the highest share of companies having ICP

Growth of ICP in CDP Annual Disclosures



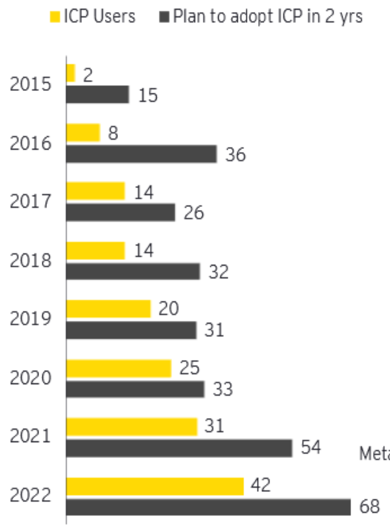
Sources:
ICP White Paper, CDP, 2021
The World Bank Publication: State and Trends of Carbon Pricing, 2023

14.3. Trends in ICP adoption : India

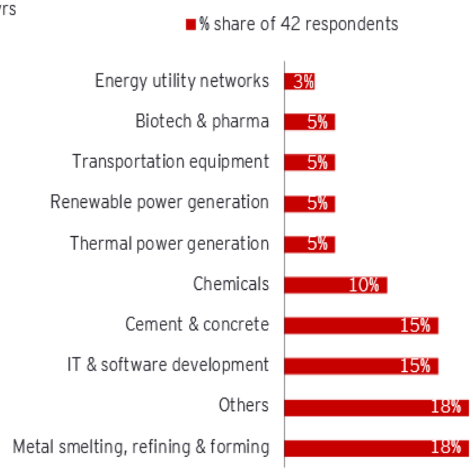
In 2022,

- **110** companies disclosed to CDP as having set or planning to adopt an Internal Carbon Price
- **Sectoral Analysis** revealed a mostly **even distribution** across the following sectors:
    - Metal smelting, refining, forming
    - IT & software development
    - Cement & concrete
    - Chemicals
    - Thermal power generation
    - Renewable power generation
    - Transportation equipment
    - Biotech & pharma
    - Energy utility networks

ICP adoption trends in India



Sector Analysis of ICP Users in India, 2022



Source: CDP India Disclosure Report, 2022

14.4. Carbon pricing disclosure by companies

ICP 2030 Vision of Leading Oil & Gas Players

Leading O&G players (**BP, Shell, Exxon, Total, Essar**) have set Internal Carbon Prices in the range of **$15-80** per ton CO_2e. They have stated future carbon prices (**2030 and beyond**) aligned to their Net Zero ambition, as follows:

Company	Last reported ICP	Year reported	ICP vision for 2030 onwards
bp	$40/t	2013	$100/t
Shell	$40-80/t	since 2000	$125-220/t
ExxonMobil	$80/t	2020	$80/t
TotalEnergies	> $40/t	2022	$100/t
NAYARA ENERGY	$15/t	2018	Not known
REPSOL	$60-70/t	upto 2025	$100/t
equinor	$55/t	2020	Not known
Chevron	Price not known	Not known	Not known

ICP disclosure by Indian companies (2021)

In 2021, leading Indian companies have set Internal Carbon Prices in the range of **$0.20-50.76** per ton CO_2e.
ACC set the highest ICP of **$50.76/t**.

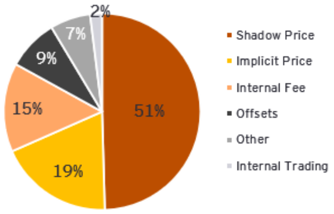
Company	Price (USD/tCO_2e)
ACC	50.76
Adani Green Energy	10.82
Ambuja Cements	33.36
Godrej Industries	10.08
HCL Technologies	3.33
Infosys Limited	14.25
JSW Energy	11.56
Mahindra & Mahindra	10.00
Tata Consultancy Services	15.30
Ultratech Cement	10.82

Source: CDP India Disclosure Report 2022

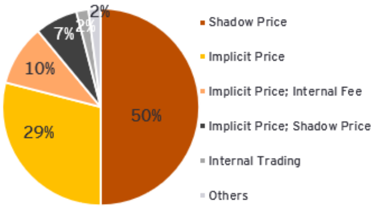
14.5. Trends in Types of ICP adopted

Shadow Price and **Implicit Price** respectively are the most widely adopted types of ICP worldwide and in India.

Types of ICP used by Global cos.
(853 total, 152 in Energy sector)



Types of ICP used by Indian
companies (31 in total)



Type of ICP adopted by leading
Oil & Gas companies

Company	Type of ICP
BP	Shadow
Shell	Shadow
ExxonMobil	Not Known
TotalEnergies	Shadow
Nayara Energy	Shadow
Chevron	Not Known
Repsol	Not Known
Equinor	Not Known

Type of ICP adopted by Indian
companies, across sectors

Company	Type of ICP
ACC	Implicit, Shadow
Adani Green Energy	Shadow
Ambuja Cements	Implicit
Godrej Industries	Shadow
HCL Technologies	Implicit
Infosys Limited	Implicit
JSW Energy	Shadow
Mahindra & Mahindra	Implicit, Internal Fee
Tata Consultancy Services	Implicit, Shadow
Ultratech Cement	Shadow

Sources:
ICP White Paper, CDP, 2021
CDP India Disclosure Report 2022
Center for Climate and Energy Solutions

15. Role of ONGC in Enabling Energy Transition

15.1. ONGC Decarbonization Initiatives

ONGC has committed for an investment of Rs. 2 lakh crores by 2038 on various decarbonization levers, which is tabulated below:

Table 29 Total Investment on Decarbonization

Mitigation Measure	2030		2035		2038	
	Project Size	Investment (Cr)	Project Size	Investment(Cr)	Project Size	Investment(Cr)
Energy Efficiency + Flare Reduction	Various projects at Asset levels	5,000	--	--	--	--
Renewables (Solar+ Onshore Wind)	5 GW	30,000	1 GW	5,000	1 GW	5,000
Green H2/G-NH3	180 KTPA GH2/ 1 MMT G-NH3	40,000	180 KTPA GH2/ 1 MMT G-NH3	40,000	--	--
CBG/ Biogas	25 Plants	1,500	--	--	--	--
Offshore Wind	0.5 GW	12,500	0.5 GW	12,000	1 GW	25,000
Pump Storage Plant (PSP)	1 GW	7,000	1 GW	7,000	1 GW	6,000
CCUS	500 KTPA	1,000	500 KTPA	1,000	1000 KTPA	2,000
Total Investment		97,000		65,500		38,000

Approx. Investment by 2038: Rs. 2 Lakh Crore

- As a responsible corporate, ONGC has entered a MOU with United States Environment Protection Agency (USEPA) in August 2007 to undertake GMI (Global Methane Initiative). In doing so, ONGC agreed to work with USEPA to cost in identifying and implementing projects to cost effectively reduce methane emissions.

- ONGC has an elaborate plan to map all production installations for reducing fugitive methane emissions. The reductions are achieved through the implementation of 'Directed Inspection and Maintenance Program' which includes the repair of pipeline leaks and replacement of valves, valve packing and rod packing seals in reciprocating compressors and use of capital-intensive technological interventions.

- Since 2007, ONGC has prevented approximately 20.48 MMSCM of methane gas leakage into the atmosphere, with emission reduction of approx. 306,250 tCO_2e through this programme.
- Furthermore, ONGC is dedicated to support green innovation, as is evident by its engagement in diverse technologies such as hydrogen production through thermochemical cycles, harnessing ocean wave energy for hydropower.
- The first phase of the geothermal project has begun in Puga, Ladakh but has faced challenges related to logistics and extreme temperatures. The second phase of this

project entails drilling two wells, including a 1000-meter well, and installing a steam turbine with a capacity of 1 MW.

- Moreover, the production of E-methane aligns with global decarbonization efforts, ensuring ONGC's resilience in an industry transitioning towards cleaner energy. Investing in E-methane technology allows ONGC to diversify its energy portfolio, reducing dependency on conventional fossil fuels. This strategic shift not only mitigates environmental impact but also future-proofs ONGC against evolving market trends and regulatory changes.
- R&D, Technology and Innovation: ONGC has tapped into diverse technologies and solutions to achieve their Net Zero goal. The Company's utilises the following technologies:
- In parallel, ONGC is aggressively pursuing energy efficiency through a multifaceted approach. The company is advancing hydrogen production technologies, including the Copper-Chlorine (Cu-Cl) and Iodine-Sulphur (I-S) cycles, with plans to scale up production to 12 metric tons per year.
- Hydrogen Production: ONGC utilises two kinds of thermochemical cycles for hydrogen production- Copper-Chlorine (Cu-Cl) cycle and the Iodine-Sulphur (I-S) cycle. These processes offer promising prospects for seamless integration with other energy systems, particularly nuclear or solar power sources. To date, OEC has successfully established both closed-loop systems for the Cu-Cl cycle and both closed and open-loop systems for the I-S cycle, albeit at laboratory or lab engineering scales. The Company aims to elevate these processes to larger scales using engineering materials, leveraging indigenous resources for this scaling-up endeavour. Ongoing work includes testing system performance over extended periods, refining separation and purification processes, and integrating molten salt for solar thermal heat storage. Moreover, efforts to scale up hydrogen production to 12 metric tons per year are currently underway.
- Kinetic Hydropower: The company has tapped into the ability of ocean waves to generate approximately 5 to 10 kilowatts per meter. Given India's extensive coastline spanning around 7500 kilometres, a mere 10% utilization of this space could yield a substantial 7500 megawatts of power generation. To harness this potential, OEC is actively engaged in the development of a 'Point Absorber Wave Energy Converter,' aimed at comprehending its mechanisms and constructing a prototype.
- Biotechnology: The heightened activity of methanogens has led to a substantial increase in methane production within coal seams, as evidenced by field testing, which has showcased a remarkable 2-4-fold increase in gas production. Methane-producing bacteria can be applied to coal seams, resulting in the generation of biogas primarily composed of methane and carbon dioxide. Through collaboration with TERI, OEC has successfully developed and demonstrated a microbial process designed to enhance gas production in Coal Bed Methane (CBM) wells at both the Jharia and Bokaro fields. Carbon isotope analysis data corroborates the stimulation of microbial communities and the

subsequent in-situ biological gas production. This innovative bioprocess promises not only to extend the lifespan of CBM fields but also to significantly boost their productivity. Additionally, research and development efforts in collaboration with TERI are underway to explore the bioconversion of CO2 into methane within select CBM wells in the Bokaro Asset region.

- Clean Development Mechanism: The company embarked on its Clean Development Mechanism (CDM) venture in 2006, marking a significant commitment to sustainability. Presently, it boasts an impressive portfolio of 15 registered CDM projects, officially recognized and accredited by the United Nations Framework Convention on Climate Change (UNFCCC). These projects collectively have the potential to generate approximately 2.1 million Certified Emissions Reductions (CERs) annually. These CERs represent tangible evidence of the company's dedication to mitigating greenhouse gas emissions and contributing to global climate change mitigation efforts. ONGC has participated in the Clean Development Mechanism (CDM) to generate Certified Emissions Reductions (CERs). ONGC has already submitted application with UNFCCC for transition of 6 CDM projects under Article 6.4 of Paris Declaration, 2015.

- Renewable Energy: The company aims to invest 1 trillion rupees to establish a renewable energy capacity of 10 GW by 2030. It is already in the process of establishing a 5 GW solar energy project in Rajasthan. The company aims to explore investment options in offshore wind energy capacity. Additionally, the company is actively exploring collaborations with industry leaders to tap into various low-carbon energy opportunities, including renewables, green hydrogen, green ammonia, and related derivatives.

15.2. Opportunities in Business transition

E-Methane

In the dynamic landscape of sustainable energy, E-methane emerges as a frontrunner in the category of e-fuels, alongside counterparts like e-kerosene and e-methanol. E-fuels, including E-methane, represent a transformative approach to energy production, being gases or liquids generated from renewable or decarbonized electricity. This fundamental distinction from biofuels, primarily derived from biomass, positions E-methane as a promising solution in the ongoing global shift towards cleaner energy sources.

The production cycle of E-methane involves harnessing renewable resources, such as solar or wind power, to generate electricity. This electricity powers an electrolysis process, splitting water into hydrogen and oxygen. The subsequent synthesis involves combining the produced hydrogen with captured carbon dioxide, resulting in the creation of E-methane. This innovative process not only ensures a sustainable and carbon-neutral source but also breaks away from traditional fossil fuel dependence.

One of the defining attributes of E-methane is its capacity to significantly reduce the environmental impact associated with conventional combustion engines. Through its entire production cycle, E-methane demonstrates a substantially lower carbon footprint when compared to traditional oil-based fuels. As industries and economies globally seek cleaner alternatives to address climate challenges, E-methane stands out as a viable and versatile solution, paving the way for a more sustainable energy future.

Production

It all depends on whether the desired end product is in gas or liquid form:

- **Gas e-fuels:** renewable hydrogen and e-methane, which can both be liquefied later, to produce liquid H2 and e-GNL respectively.
- **Liquid e-fuels**: like e-methanol and e-crude, also known as synthetic crude oil, which make e-kerosene and e-diesel.
- **Gas or Liquid form:** synthetic ammonia.

Depending on the form or the e-fuel required, either a Power-to-Gas or Power-to-Liquid process is used. Both production processes involve two or three phases, with first hydrogen (H2) production by water electrolysis from renewable electricity, associated with another molecule - CO2 for e-crude and synthetic methane or methanol, or nitrogen (N2) for synthetic ammonia. Synthetic crude oil must be refined (like fossil oil) to produce synthetic kerosene or diesel.

E-methane, e-methanol, e-diesel, and e-kerosene are synthetic hydrocarbons, so their production processes require CO_2. This vital element can either be captured directly from the atmosphere or taken from industrial plants that use fossil fuels. Different sources of

CO_2 (biomass, industry, air) have an impact on the synthetic fuel's lifecycle analysis, environmental benefits, and production cost.

An alternative method of synthetic crude oil production is high temperature H_2O/CO_2 co-electrolysis. As it does not require the input of renewable hydrogen, CO_2 being introduced at the beginning, the process is a stage shorter. This is an advantage as it improves productivity (by up to 30%) and, in theory, reduces investment costs. However, the technology is not yet very mature and most initial production projects opt for hydrogen production by low temperature electrolysis in their first phase.

Application of E-Methane

In the realm of sustainable mobility, E-Methane emerges as a crucial player, especially in addressing the challenges posed by heavy mobility, which contributes significantly to global CO2 emissions. While the electrification of road transport is gaining prominence, the limitations of decarbonization in maritime and air transport sectors persist. E-fuels, including E-Methane, step into this gap, offering a key solution for sectors where electrification alone is not feasible. What sets E-fuels apart is their compatibility with existing fossil fuel infrastructure, providing a seamless transition and competitive advantage over biofuels. Projections indicate that by 2070, E-kerosene could fulfill 40% of aviation energy demand, showcasing the vast potential of E-fuels in revolutionizing the aviation sector. Beyond aviation, initiatives worldwide are exploring the production of green E-fuels, including synthetic methanol, to power ships and meet the energy demands of maritime, rail, and road transport. Notably, projects in regions like the North Sea are actively working towards developing competitive and sustainable E-Methane solutions, exemplifying a concerted global effort to reshape the future of transportation (source10)

Case study

Case 1: Santos - Pioneering E-Methane Production

Santos, through its visionary energy transition arm, Santos Energy Solutions, is spearheading a landmark project in collaboration with Osaka Gas Australia (OGA) to produce carbon-neutral e-methane at a demonstration scale. With a robust commitment to creating a cleaner energy future, Santos is embarking on Pre-Front End Engineering and Design (Pre-FEED) work to pave the way for this transformative initiative.

The project encompasses a comprehensive Pre-FEED phase, covering studies on renewable power, carbon capture infrastructure, site selection for e-methane and green hydrogen plants, and optimization of production efficiency. Santos and OGA are poised to assess costs, schedules, feasibility, and risks, underlining their dedication to delivering decarbonization projects and clean fuels.

Santos emphasizes the strategic importance of gas in the transition to a decarbonized future. The e-methane produced in this endeavor uniquely addresses challenges related to hydrogen transport and export. Leveraging existing infrastructure for transport, liquefaction, and end-user delivery ensures a carbon-neutral outcome across all scopes, cementing its place as a sustainable energy solution.

The project involves the generation of e-methane from green hydrogen produced through water electrolysis powered by renewable energy, coupled with the capture of CO2 at industrial sites or through Direct Air Capture technology. This innovative approach not only aligns with Santos' net-zero by 2040 commitment but positions the company as a trailblazer in sustainable energy production.

Santos' collaboration with OGA aims for FEED entry in 2024, with the goal of being Final Investment Decision ready in 2026. The planned plant, with a capacity of 10 TJ/day, is poised to export approximately 60,000 tonnes of e-methane annually by 2030. This initiative aligns with Santos Energy Solutions' ambitious plans for one of the world's largest Carbon Capture and Storage projects in Moomba, South Australia, further emphasizing their dedication to pioneering solutions for a cleaner, greener future.

Oil to Chemical

India faces a trade deficit of INR 33,000 crores as it heavily relies on petrochemical imports in 2019-20. In the future, the demand for petroleum-derived fuels will decrease due to the rapid adoption of electric vehicles and renewable energy. Hence, it is imperative to explore alternative strategies such as converting crude oil directly to petrochemicals. This initiative will align the business strategy of ONGC to India's vision of 'Atmanirbhar Bharat Abhiyan' and 'Make in India'. The global petrochemical industry is estimated to grow from USD 536 billion in 2020 to USD 860 billion by 2028, indicating a promising future for the sector with a CAGR of 6.4%.India is expected to account for ~20% of the global capacity addition (158 MTPA) by 2030.

Petrochemicals	Major Products	End-user Applications
Synthetic Fibres	Acrylic Fibre, Nylon Filament Yarn, Nylon Industrial yarn, Polyester filament yarn, polypropylene filament yarn, polypropylene staple fibre, Elastomeric Filament yarn	Clothing, upholstery, carpeting, industrial fabrics, mechanical parts including bearings, packaging materials
Fiber Intermediates	Acrylonitrile, Caprolactum, Mono Ethylene Glycol, Purified Terephthalic Acid	Production of synthetic fibers such as polyester and nylon
Polymer	LDPE, HDPE, Polystyrene, Polypropylene, expandable polystyrene, LLDPE, PVC Compound	Packaging materials, construction materials,

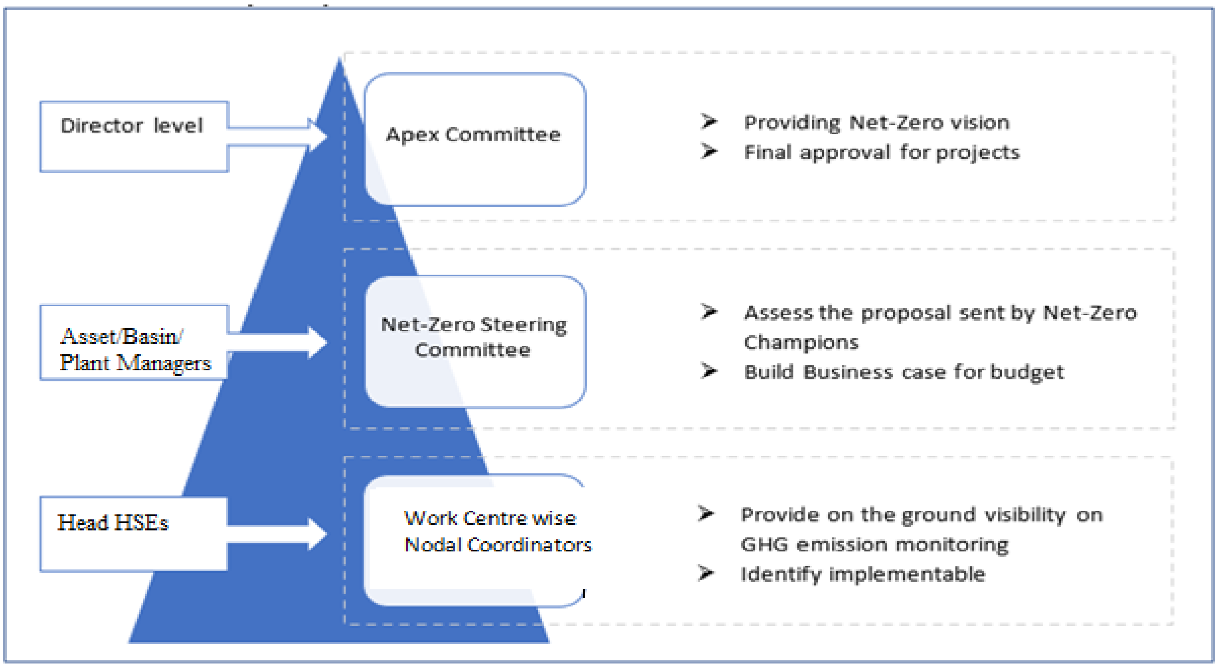
		automotive parts, consumer goods, medical devices
Synthetic Rubber (Elastomers)	Styrene Butadiene Rubber, Polybutadiene rubber, Ethyl propylene dimer, Ethyl vinyl acetate, nitrile butadiene rubber, butyl rubber	Tires, automotive parts, industrial hoses, seals, adhesives, gaskets,
Synthetic detergent intermediates	Linear Alkyl Benzene, Ethylene Oxide	Surfactants, personal care products such as shampoos, emulsifiers in agricultural products,
Performance Plastics	ABS Resin, Nylon-6, Polymethyl Methacrylate, Styrene Acrylonitrile, Polyester chips, Polytetrafluoroethylene (PTFE)	Electronics, medical devices, automotive parts, aerospace components, consumer goods
Olefins	Ethylene, Propylene, Butadiene	Packaging materials, construction materials, automotive parts, consumer goods, textiles
Aromatics	Benzene, Toluene, Paraxylene, Mixed Xylene, ortho-xylene	Plastics, synthetic fibers, resins, coatings, pharmaceuticals
Other	Isopropanol, Ethylene Dichloride, polycarbonate, ethyl benzene, polyol, and many more	Cleaning agents in household and industrial purpose, compact discs, DVDs, safety glasses, artificial leather, etc.

15.3. Governance Structure

The foundation of any successful framework is a robust governance structure. A dedicated governance structure shall streamline ONGC's it journey towards decarbonization and achieve its Net-Zero targets.

A reference three-tiered governance structure could enable close monitoring and progress of ONGC's Net-Zero journey as describe below:

Figure 57 Reference Governance Structure



Net-zero Committee

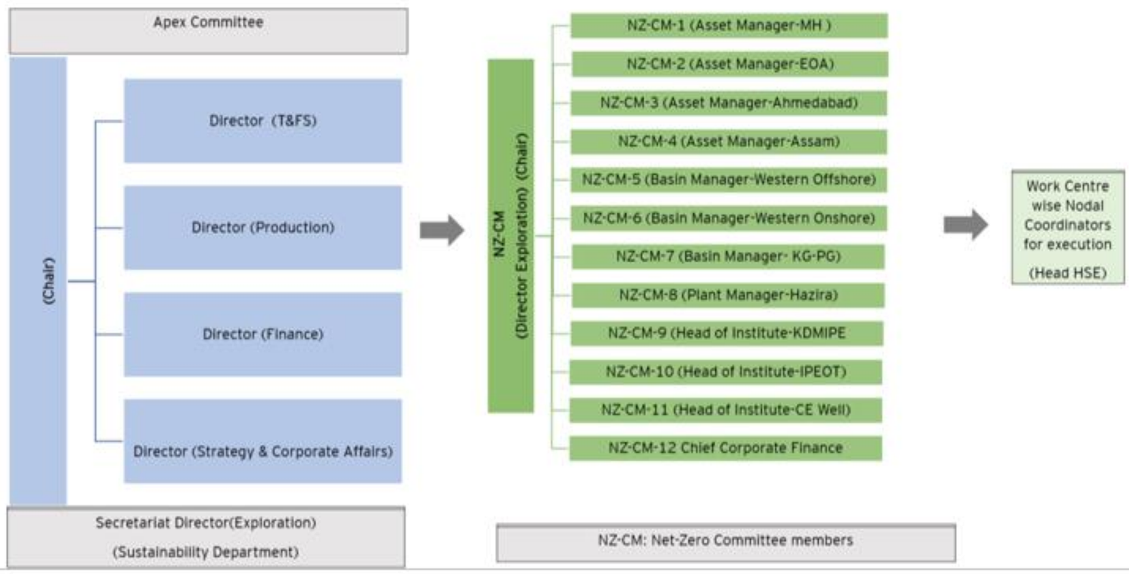


Table 30 RACI Matrix

Activity	Net-Zero Champion (NZ-C)	Net-Zero Committee member (NZ-CM)	Apex Committee
Accounting and Monitoring of GHG emissions	Responsible	Accountable	Informed
Identification of decarbonization project (Scope 1&2)	Responsible	Accountable	Consulted
Identification of value chain carbon abatements opportunities (Scope 3)	Responsible	Responsible	Accountable
Identify opportunities in energy transition	Responsible	Responsible	Accountable
Identify opportunities in carbon capture	Responsible	Accountable	Consulted
Identify offsetting opportunities (Carbon offsetting)	Consulted	Responsible	Informed
Training and development on Net-Zero	Responsible	Responsible	Accountable
Internal audit of Net-Zero achievements	Consulted	Responsible	Accountable
GoI level Policy/ Regulatory advocacy for Net-Zero	Consulted	Responsible	Responsible

- Responsible - Individual or Group that has to carry out the task.
- Accountable - Individual accountable for the task being done correctly.
- Consulted - Individual or group that will be Consulted.
- Informed - Individual or group that will be informed of the progress of the task.

16. Focus Areas & Action Points

To mitigate Scope 1 and 2 operational emissions effectively, ONGC plans to integrate renewable energy into its operations in a phase-wise manner. This approach involves comprehensive measures spanning from short-term to long-term goals. These efforts will be aiming to develop renewable energy hybrid, offshore wind, and small hydro power plant projects. The systematic deployment of renewable energy infrastructure is projected to significantly reduce emissions from captive power generation.

ONGC may plan to implement integration of renewable energy as per these options:

- Operation level,
- State level (based on operations),
- National/organizational level

A. Operational Level:

Based on Decarbonisation Roadmap, 2038, the Asset wise RE capacity for ONGC:

Operations	RE Capacity for each Assets (MW)			
	Assets/Plants	**2030**	**2035**	**2038**
Offshore	MH Asset & Services	1840	2640	2920
	B&S	840	1290	1420
	N&H	345	495	545
	EOA	106	152	167
Onshore	Ankleshwar	427	500	552
	Mehsana	140	164	181
	Assam	60	70	75
	Ahmedabad	50	58	64
	Rajahmundry	35	46	51
	Cauvery	22	26	30
	Jorhat	4	4	5
Plant	Hazira	1	1	1
	Dahej	1	1	1
Others	**Institutes, offices and other small assets**	**23**	**23**	**23**
Overall ONGC	**Total**	**3894**	**5470**	**6035**

Note:

- Capacities are based on FY 22 Baseline Emissions and projected emissions in case of Business-As-Usual and Business growth.
- RE Capacities may include RE- Hybrid, Offshore Wind, Small Hydro Power plant.

ONGC may plan to implement above RE capacities at Asset level, however there may be challenges related land requirement, cost economics due to small scale, or any other operation related challenges. Hence, ONGC may opt for state level RE implementation as given in the next section, however, all onshore operations may plan to reduce NG consumption for captive power generation as per the details given below:

Indicative targets for ONGC onshore operations for reduction in NG consumption for captive power generation:

KPIs for Onshore Operations	FY25	FY26	FY27	FY28	FY29
Assets	>10%	>30%	>40%	>60%	>80%
Plants		>50%	>80%		
• Onshore Assets and Plants should achieve maximum Grid Electricity Supply to ensure minimum consumption of NG for Captive Power Generation. Electrification will lead to easy access to green power. • Existing assets for gas based captive power maybe used for CBG based power generation.					
• It can be done in phase wise manner as suggested above indicatively.					
• Alternatively, all Onshore Assets and Plants may also plan to achieve RE capacity as per Net Zero Roadmap 2030 projected RE capacity requirement.					

B. State level

ONGC may also look at state level implementation based on concentration of its operations. In the table below, state-wise RE requirement

State wise RE capacity requirement for ONGC on the basis of it's operation is as follows :

State level projected RE requirement by FY 2038 - ONGC

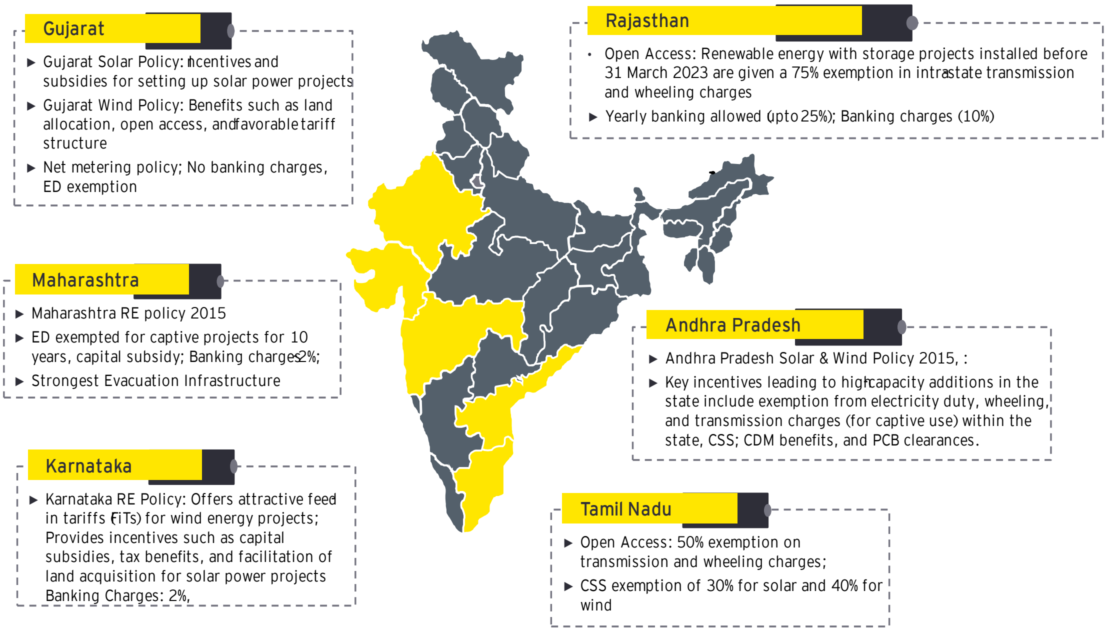
State	Renewable Lever	Projected Capacity (In MW)	Emission Reduction (In Mn tCO2e)
Gujarat	RE- Hybrid	801.56	0.78
Maharashtra	RE- Hybrid	3120.63	6.41
	Offshore Wind	1759.02	
Tamil Nadu	RE- Hybrid	28.41	0.02
Andhra Pradesh	RE- Hybrid	194.74	0.29
	Offshore Wind	46.25	
Assam	Small Hydro	84.61	0.23
Total		6035	7.74

Land requirements for Solar and Wind Power Plant

State	Renewable Lever	Projected Capacity (in MW)	Solar Capacity (in MW)	Land Requirement (in Acres)	Wind Capacity (in MW)	Land Requirement (in Acres)
Gujarat	RE- Hybrid	801.56	240.468	961.872	561.09	981.90
Maharashtra	RE- Hybrid	3120.63	936.189	3744.756	2184.441	3822.77
Tamil Nadu	RE- Hybrid	28.41	8.52	34.08	19.88	34.79
Andhra Pradesh	RE- Hybrid	240.99	72.29	289.16	168.69	295.20

Assumptions:

- RE-Hybrid includes 30% solar energy and 70% wind energy.
- For Solar, the land requirement is taken as 4 Acres/MW as per the CEA electricity plan 2022.
- For Wind, the land requirement is taken as 1.75 Acres/MW as per the CEA electricity plan 2022.
- **Several States have favourable policies which may be helpful to achieve ONGC's targets**



C. **National/Organizational level:**

Keeping in economics of scale, land availability, favourable state policies ONGC may also explore other states across country. As on 31st March 2023, state-wise RE potential and installed capacities are given in the below table(source MNRE):

State-wise Renewable Energy potential and installed capacity in India as on 31st March, 2023 :

#	States / UTs	Solar power		Wind power			Small hydro Power	
		Potential Capacity	Installed Capacity *	Potential Capacity at 100 M	Potential Capacity at 120 M	Installed Capacity	Potential Capacity	Installed Capacity
		GW						
1	Andhra Pradesh	38.44	4.53	4.10	44.23	4.10	0.41	0.16
2	Arunachal Pradesh	8.65	0.01	0.00	0.00	0.00	2.07	0.13
3	Assam	13.76	0.15	0.00	0.00	0.00	0.20	0.03
4	Bihar	11.2	0.19	0.00	0.00	0.00	0.53	0.07
5	Chhattisgarh	18.27	0.95	0.00	0.08	0.00	1.10	0.08
6	Goa	0.88	0.03	0.00	0.00	0.00	0.01	0.00
7	Gujarat	35.77	9.25	10.90	84.43	9.98	0.20	0.09
8	Haryana	4.56	1.03	0.00	0.00	0.00	0.11	0.07
9	Himachal Pradesh	33.84	0.09	0.00	0.00	0.00	3.46	0.97
10	Jammu and Kashmir	111.05	0.06	0.00	0.00	0.00	1.71	0.19
11	Jharkhand	18.18	0.11	0.00	0.00	0.00	0.23	0.00
12	Karnataka	24.7	8.24	5.31	55.86	5.29	3.73	1.28
13	Kerala	6.11	0.76	0.06	1.70	0.06	0.65	0.27
14	Madhya Pradesh	61.66	2.80	2.84	10.48	2.84	0.82	0.12
15	Maharashtra	64.32	4.72	5.08	45.39	5.01	0.79	0.38
16	Manipur	10.63	0.01	0.00	0.00	0.00	0.10	0.01
17	Meghalaya	5.86	0.00	0.00	0.00	0.00	0.23	0.03
18	Mizoram	9.09	0.03	0.00	0.00	0.00	0.17	0.05
19	Nagaland	7.29	0.00	0.00	0.00	0.00	0.18	0.03
20	Odisha	25.78	0.45	0.00	3.09	0.00	0.29	0.12
21	Punjab	2.81	1.17	0.00	0.00	0.00	0.58	0.18
22	Rajasthan	142.31	17.06	5.19	18.77	5.19	0.05	0.02
23	Sikkim	4.94	0.00	0.00	0.00	0.00	0.27	0.06
24	Tamil Nadu	17.67	6.74	10.15	33.80	10.02	0.60	0.12
25	Telangana	20.41	4.67	0.13	4.24	0.13	0.10	0.09
26	Tripura	2.08	0.02	0.00	0.00	0.00	0.05	0.02
27	Uttar Pradesh	22.83	2.52	0.00	0.00	0.00	0.46	0.05
28	Uttarakhand	16.8	0.58	0.00	0.00	0.00	1.66	0.22

29	West Bengal	6.26	0.18	0.00	0.00	0.00	0.39	0.10
30	Delhi	2.05	0.22	0.00	0.00	0.00	0.00	0.00
31	Union territories +Others	0.79	0.22	0.00	0.01	0.00	0.01	0.01
	Total (GW)	749	66.78	43.77	302.09	42.63	21	4.94

(Source: Ministry of New and Renewable Energy)

*Split of State-wise installed capacity of Solar Power as on 31.03.2023

#	STATES / UTs	Solar Power				
		Ground Mounted Solar	Rooftop Solar	Hybrid Solar Comp.	Off-grid Solar	Solar Power Total
		(MW)	(MW)	(MW)	(MW)	(MW)
1	Andhra Pradesh	4276.67	169.18	0.00	88.34	4534.19
2	Arunachal Pradesh	1.27	4.34	0.00	6.03	11.64
3	Assam	105.00	33.48	0.00	9.44	147.92
4	Bihar	141.06	30.55	0.00	21.28	192.89
5	Chhattisgarh	507.18	54.91	0.00	386.73	948.82
6	Goa	0.95	25.42	0.00	0.12	26.49
7	Gujarat	6580.02	2492.11	128.14	54.30	9254.57
8	Haryana	265.80	429.34	0.00	334.02	1029.16
9	Himachal Pradesh	38.10	19.31	0.00	30.08	87.49
10	Jammu and Kashmir	8.49	24.4	0	24.35	57.24
11	Jharkhand	19.05	38.33	0.00	48.46	105.84
12	Karnataka	7617.20	593.90	0.00	30.31	8241.41
13	Kerala	299.85	440.59	0.00	21.00	761.44
14	Madhya Pradesh	2459.02	257.22	0.00	85.90	2802.14
15	Maharashtra	3009.14	1488.76	0.00	225.00	4722.90
16	Manipur	0.00	6.36	0.00	5.92	12.28
17	Meghalaya	0.00	0.21	0.00	3.94	4.15
18	Mizoram	20.10	1.56	0.00	6.35	28.01
19	Nagaland	0.00	1.00	0.00	2.04	3.04
20	Odisha	403.56	21.66	0.00	27.95	453.17
21	Punjab	831.75	254.66	0.00	80.85	1167.26
22	Rajasthan	14025.83	887.00	1579.00	563.87	17055.70
23	Sikkim	0.00	2.76	0.00	1.92	4.68
24	Tamil Nadu	6285.61	386.07	0.00	64.75	6736.43
25	Telangana	4360.49	296.83	0.00	8.71	4666.03
26	Tripura	5.00	4.78	0.00	7.82	17.60
27	Uttar Pradesh	2074.50	265.10	0.00	175.62	2515.22
28	Uttarakhand	298.40	262.71	0.00	14.42	575.53
29	West Bengal	113.80	53.04	0.00	13.14	179.98
30	Delhi	8.96	207.84	0.00	1.46	218.26
31	Union territories+Others	45.58	124.51	0	48.79	218.88
	Total (MW)	53802.38	8877.93	1707.14	2392.91	66780.36

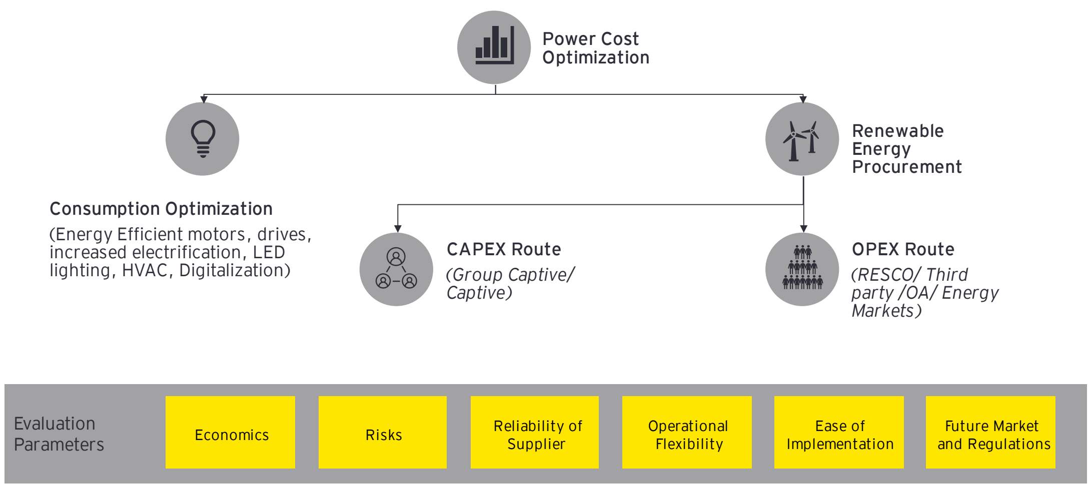
(Source: Ministry of New and Renewable Energy)

Based on the potential and current installed capacity of renewable energy sources in different states of India, ONGC may plan to transition its captive power requirements to renewable energy.

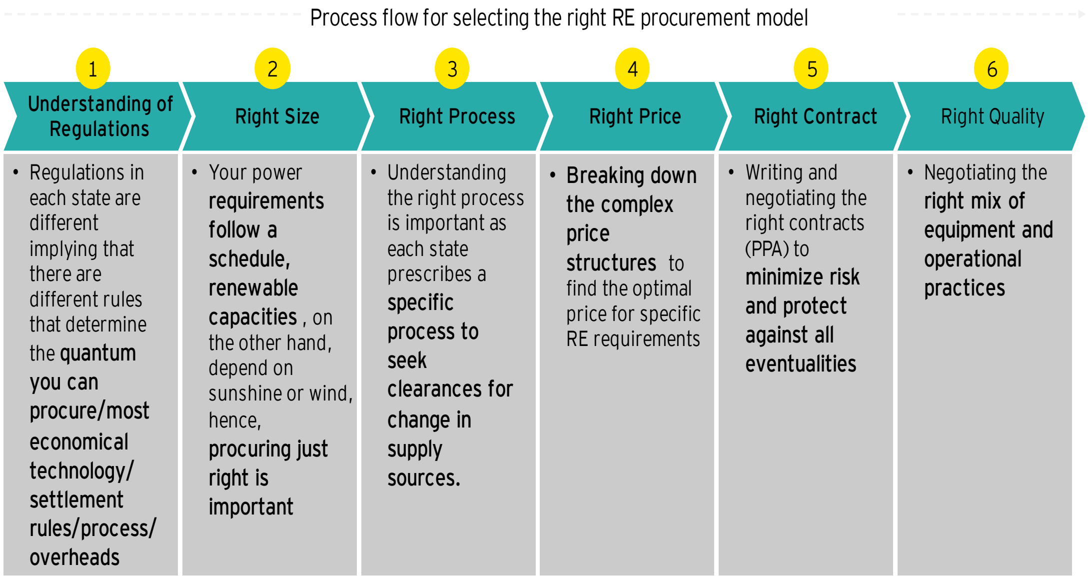
According to ONGC's Decarbonisation Roadmap 2038, the required renewable energy capacity at the organizational level is as follows:

Scope 1 and 2 Levers (Operational Emissions)	Short Term	Short to Medium Term (By FY 30)	Medium to Long Term (By FY 35)	Long Term (By FY 38)
Renewable Energy	**1) Pre-feasibility studies/survey for all capacities and targets** **Identification of suitable location and land acquisition** **Collaboration with State government and technology providers** *RE Hybrid: 30% Solar and 70% Wind	**Intervention:** Total: 3.894 GW RE Hybrid: 3.20 Offshore wind: 0.62 Small Hydro: 0.065	**Intervention:** 5.470 GW RE Hybrid: 3.76 Offshore wind: 1.64 Small Hydro: 0.077	**Intervention:** 6.035 GW RE Hybrid: 4.145 Offshore wind: 1.805 Small Hydro: 0.085

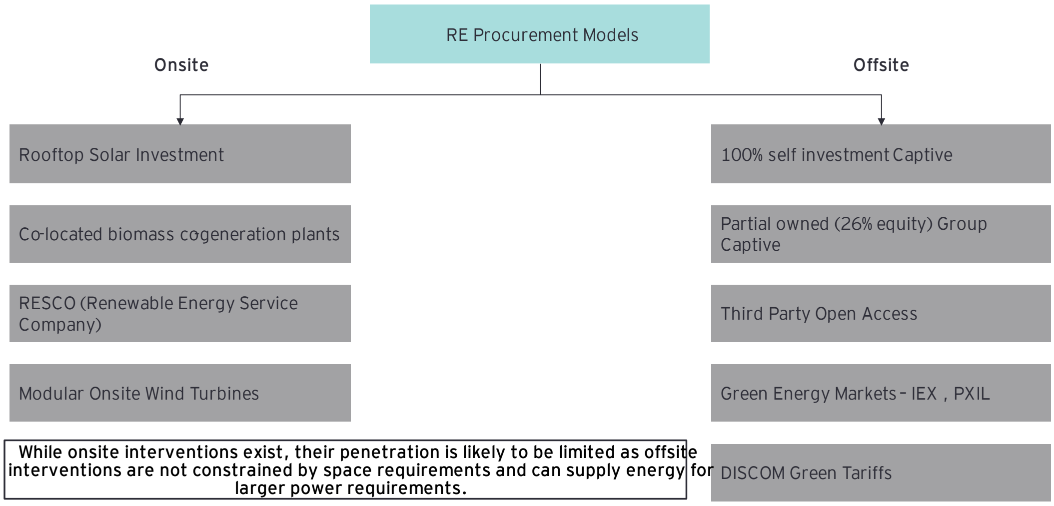
Penetration of RE Will be Driven by Supply-side Interventions



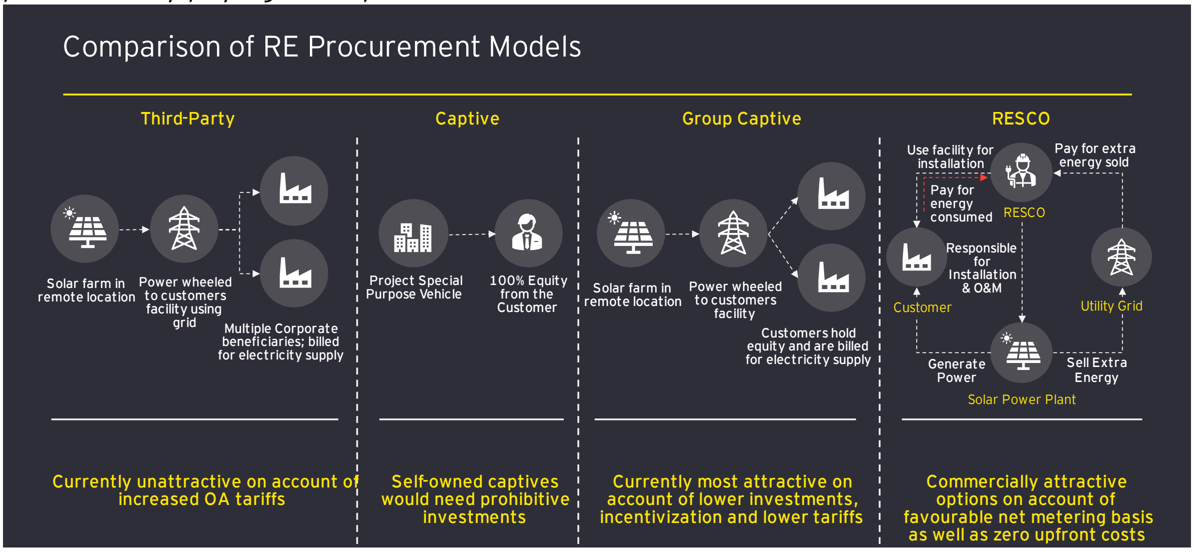
Key Considerations for RE Procurement



Various RE Procurement Models:



As per the India Energy Exchange power rates, current Weighted Average Market Clearing price for green power is Rs. 3.48 as compared to normal power, which is Rs. 3.06/kWh. Which shows that if ONGC operations are connected with grid, green power may be purchased by paying some premium over normal rates.



Case Study:
Electrification of offshore platforms using offshore and onshore wind power

Power-from-shore

Johan SverdupField of Equinor

Low Upstream GHG Intensity: CO2 emissions from the production of oil and gas from the field are estimated at just 0.67 kg CO2/barrel. CO2 emission reduction from the field is estimated at more than 0.46 million tCO2 per year

Phase 1: Power supply capacity of 100 MW, which enabled the production of up to 400,000 per day

In the first phase, the electrical equipment (HVDC) for the converter stations both at Haugsneset and on the riser platform was delivered by ABB. All work related to the construction of the converter station at Haugsneset was done by Aibel. NKT was responsible for the delivery and installation of the 200 km power cables

Phase 2: In 2022, the power from shore capacity is expanded to another 200 MW to power other fields

Enhanced Working Environment through Power from Shore Collaboration: Power from shore collaboration with Master Marine ensures power supply to temporary accommodation rig Haven and offshore workers during project finalization, improving the working environment significantly

Win-Win Outcome: Reduced Noise and Emissions for Offshore Workers: Johan Sverdrup partnership achieves win-win results by reducing offshore noise and local emissions, benefiting around 900 workers and the environment

Offshore wind

Hywind Tampen project by Equinor

Reduced Emissions: This project will reduce CO2 emissions from the field by about 0.2 million tonnes per year

Partners: Equinor, Petoro, OMV, Vår Energi, WintershallDea and INPEX Idemitsu

Hywind Tampen has a system capacity of 88 MW

The wind farm is located some 140 kilometers from shore

Water depth: between 260 and 300 meters

The turbines are installed on a floating concrete structure with a joint mooring system

Enova and the Business Sector's NoX Fund have supported the project by NOK 2.3 billion and NOK 566 million respectively to stimulate technology development within offshore wind and emission reductions

Electrification- ADNOC

Reduced Emissions: Announced USD 3.6 billion, first of its kind, sub-sea transmission network to reduce offshore carbon footprint by more than 30%

Partners: ADNOC partnered with Emirates Water and Electricity Company (EWEC) to supply up to 100% of nuclear and solar power

General Electric has technology for the supply of Onshore Power HVAC to Offshore Hub Power Supply MVDC which has following value proposition:

- DC cable is cheaper than AC cable
- Lower losses due to DC transmission
- Modular and proven AC/SC converter(MMC)
- Controllability and flexibility
- High Efficiency
- No filter
- Bidirectional Control voltage & reactive power at both end cable
- Fault level decoupling between distribution systems
- Less expensive than HVDC(no large civil work)

Upcoming trends

Integrating Energy Storage System with Renewable Energy	Increased adoption of Green Tariffs	Virtual Power Purchase Agreement	International Renewable Energy Certificate (I-RECs)
		VPPA	THE INTERNATIONAL REC STANDARD
Storage of excess electricity in energy storage systems *Commercial viability depends on location, regulation, and CAPEX* *Renewable energy+storage benefits OA consumers with diesel -power generators*	*C&I consumers can procure green energy through a green tariff* *At present, 5 states offer Green Tariffs:* *Maharashtra: 0.66 INR/kWh* *Gujarat, Karnataka: 0.5 INR/kWh* *UP: 0.54 INR/kWh* *Andhra Pradesh: Fixed 12.25 INR/kWh*	*VPPA involves selling electricity at market price with a pre -agreed strike price.* *VPPA segment offers immense opportunities for open-access stakeholders*	*IRECs offer independent issuance, sale, purchase, and retirement mechanism* *IRECs support organizations voluntarily purchasing renewable energy* *IRECs provide traceability compared to traditional RECs*

On the basis of above focus areas on the basis of Market research and various case studies following are suggested actionable points:

Out of overall emissions, Offshore Assets contributes to about 54%, Onshore Assets contributes to about 14%, Plants contributes to about 12 % and other services contributes to about 20%. Among all the ONGC operations Captive Power generation contributes to approximately 50% of overall emissions. Following immediate action points may lead to substantial decrease in net emissions of ONGC operations:

- Electrification of Onshore operations as per the RE procurement options given above.
- Pe-feasibility studies for electrification of offshore operations, GE technology of HVAC(onshore) to MVDC (offshore) may be explored.
- Pre-feasibility studies for onshore renewable power capacities, if ONGC is looking for in-house RE capacities.
- Pre-feasibility studies for Offshore wind power capacities. Case Studies of Equinor and ADNOC may be explored.
- Land acquisition for the RE infrastructure
- Strategic Partnership with various technology and service providers.
- Pre-feasibility studies for Battery Energy Storage Systems.
- Benefits from various government incentives and schemes.

Results of above studies may be presented before top management for further approval and execution.

17. Annexure

Annexure 1 - Technology Providers for Renewable Energy

List of Service Providers:

RE Hybrid • Renew solar power • Greenko Energies • HES Infra • Ayana Renewables Power • Rosepetal Solar Energy Pvt. Ltd (Adani Power)	**RE Hybrid** • Renew solar power • Greenko Energies • HES Infra • Ayana Renewables Power • Rosepetal Solar Energy Pvt. Ltd (Adani Power)	**Solar Developer & Wind Solar Hybrid** • Avaada • Ayana Renewables • NTPC Renewable Energy • Adani Green • Tata Power Solar • Azure Power • Juniper Green Energy • ABC Renewable Energy • ACME Solar • Enel Green Power India • O2 Power • Amplus Solar • Fourth Partner • Hartek Group
Onshore Wind Project Developer • ReNew • Greenko • Hero • JSW Renewable • Alfanar • Inox Wind • Evergreen • Adani Green • Sembcorp • Torrent Power • Apraava • Atria Power • Continuum • Ecoren • Enel • Leap Green Energy • Malpani • Suzlon Energy • Siemens Gamesa Renewables • Vestas • Inox Wind • Orient Green Power	**Green Hydrogen** • Adani New Energy • Reliance Industries • Ayana Renewables • Greenko • ReNew • NTPC • L&T • ACME **BESS** • NTPC Renewable Energy • ACME Barmer Solar • ReNew • Greenko • SunSource • Sembcorp • IndiaGrid • Eden Renewable • Sterlite Power • Azure Power • Hartree Partners Singapore	OffShore (Not in India Yet) • Orsted • Siemens Gamesa • Vestas • GE • RWE • Equinor • Innogy • Mitsubishi Heavy Industries • ABB

Annexure 2 - Technology providers for CCU

- Carbon Upcycling
- Carbon Clean
- LanzaTech
- Summit Carbon
- Dimensional Energy
- Novonutrients
- New Iridium

Annexure 3 - Technology providers for zero routine flaring

Company	Aspen Engineering Services	GTUIT Corporation	Pioneer Energy
Technologies	NGL Pro	Gas Treatment Using Intelligent Technology (GTUIT)	Skid-mounted mechanical refrigeration-based plants (MRUs)
Company Overview	Cost technology for flare reduction, gas conditioning, and NGL recovery. Eliminate the need for glycol.	Creates solutions for flare capture and associated gas conditioning challenges.	Manufacture specialized products such as LPG, condensate, light naphtha, and lean conditioned gas. Characterized by a high degree of automation.
Technology & Operating Conditions	Gas treatment and NGL extraction	On-Site gas processing using mechanical refrigeration and gas compression	Flare catcher - Gas processing plant using mechanical refrigeration to chill to as cold as -65ºC.
Size Range and Cost	Scalable and Modular. 3MMSCFD on an 8″ *25″ skid	Scalable and Modular; Cost: USD 1000-2000 per MCFD	Modular; Unit Size: 1-30 MMSCFD
Business Model	Sale, Lease, or License	Sale, Train, and Support	Direct sale internationally
Experience to date	9 commercial units in operation	68 MMSCFD processing facility in North America; 800,000 operational hrs	Completed more than 20 installations

Power Generation Technology Providers

Company	Capstone Green Energy Corporation	MESA Natural Gas Solutions LLC	SMART Energy – Gas to Grid	Turbogenerator – Mitsubishi Heavy Industries Group
Technologies	Micro-turbine power generation	Power generation	Modular, containerized, integrated small-scale power generation	ORC turbogenerators
Company Overview	Capstone's microturbine energy systems offer efficient, low-emission, scalable power generation for various industries, from	Mesa is a top power solutions company, providing natural gas & liquid propane-powered generator sets for mobile & stationary applications, and minimizing	Offers Gas-to-Grid in a box, a scalable flexible option for monetizing associated gas to generate electricity	ORC turbogenerator uses a thermal boiler fed by flare gas to vaporize an organic fluid used to generate electricity in a Rankine cycle.

	65kW to multiple MWs.	emissions for customers.		
Technology & Operating Conditions	Minimal pre-processing; Gas Inlet pressure: 75-80 psig Gas volume: C65: 0.021 MMCFD; C200S: 0.055 MMCFD; C600S: 0.16 MMCFD; C1000S: 0.27 MMCFD	Gas inlet pressure: 6-90 psi; Handles variable gas composition; Automatic fuel switching: AG, propane, CNG, LPG	No gas treatment is required for gas up to 65% CO2 and/or 40% non-methane hydrocarbons Gas inlet pressure >5 psi; Easy relocation	Gas inlet pressure: >1.5 psi; Handles variable gas composition, flow, and fuel ; Multi-fueling by mixing flaring gas with NG/other fuels (Diesel)
Size Range and Cost	Scalable and Modular Unit Size: 65, 200, 600, 800, 1000 kW Cost: USD 1000-1700/kW	Relocatable Units: 70-350 kW, 480 V Stationary standby units: 300-400 kW, 480 V Power conversion efficiency: 0.25 mcf/day per kW	Scalable and Modular Range: 600-1000 kW utilizing ~0.25 MMSCFD gas Energy conversion efficiency: 33%	Scalable and Modular; Unit sizes of 200 kW to 20 MW Cost: USD 4000-4500/kW for 300-600 kW; USD 2800-3300/kW for 1-5 MW; USD 1700-220/kW for >5 MW
Sale, Train, and Support	Sale through an authorized partner; Lease and financing options also available	Sale, Lease, or Joint Venture	Rental, Leasing, or energy conversion service	Sale, Lease (through partnership with MHI)
Experience to date	Several Units of C65, C800S, and C1000S operating on wet flare gas in Europe, South America, US, and Russia	450 MW Power Gen fleet, more than 20 million runtime hours using associated gas; 32 MW of commercial & industrial microgrids installed since 2018	3 units are operational in Ecuador >300 MW using associated gas	330 plants worldwide and 11,000 GWh of global electricity production. A commercial plant of 1.8 MW is operating on flare gas in Osa-Perm Russia since Jan 2015

Table 31: Technical Solutions available in the market

CNG Technology Providers

Current Marine CNG developers	Current Onshore CNG developers
CE Tech (Composite or pipe steel)	FIBA Technologies (Steel tube trailers)
Ener Sea Vo trans (Steel Cylinders)	GTM Type III cylinders module
Knutsen OAS shipping (Steel cargo tank cylinders)	Galileo Virtual Pipeline
Transocean Gas (Composite HDPE and fiberglass cylinders)	Lincoln TITAN 4 composite cylinders

Mini GTL (Gas to Liquids) Technology Providers

Company	Compact GTL	Gas Technologies LLC	Grey Rock
Technologies	Small scale GTL via a patented two-stage Fischer-Tropsch process	Gas Techno® single-step GTL conversion process	Gas-to-liquid Fischer Tropsch conversion
Company Overview	An early leader in the development of small-scale GTL technologies	Specialises in modular GTL plants that convert AG to high-value chemicals using Patented Gas Techno single step GTL conversion process	Greyrock Energy specializes in small-scale GTL FT plants and offers P-class plants (>500bpd) and M-class "Micro-GTL" units (>5bpd).
Technology & Operating Conditions	Small-scale GTL via a two-stage patented FT process Product: Synthetic Crude/Diesel	Direct Partial Oxidation of NG to produce Methanol, Ethanol, and Formaldehyde. One-step process, no catalyst, and syngas	Gas-to-Liquids Fischer Tropsch conversion Proprietary catalyst that directly converts syngas to diesel
Size Range and Cost	Gas supply: 10-150 MSCFD Modular	Scalable and Modular; Unit sizes available: 0.3-30 MMSCFD Cost: 0.3 MMSCFD: 1300 USD/TPA 5 MMSCFD: 450/TPA	Scalable and Modular; Unit size: M class units for flared gas: 0.5 MMSCFD
Business Model	License, design as well as Build/Own/Operate for smaller capacities	Design, Build, and Operate	Licensing or Greyrock JV partners will Build/Own/Operate Plants
Experience to date	Commercial demonstration plant operated successfully for 3 years with Petrobras in Brazil	0.3 MMSCFD GTL (Methanol) plant in Baken Area in North Dakota running on flare gas	A Rocky Mountain GTL 500-bpd mini-GTL plant in Alberta-Canada

Mini Liquified Natural Gas (LNG)

i) Berens group DMCC: The company provides small-scale LNG liquefaction plants, available in various sizes, catering to different capacity requirements. Additionally, they offer LNG ISO tanks designed for both storage and efficient transportation. They can handle sudden fluctuations in gas flowrate and composition. Their LNG ISO tanks have a 110-unit holding time, are characterized by their scalability and modular design. These tanks can be leased for a minimum period of three years and offers an end-to-end LNG supply chain service. They hold a notable position as one of the two prominent companies engaged in the distribution of LNG via road tankers and ISO tanks in India, underscoring their prominence in the industry.

ii) Chart Industries: The company specializes in the creation and production of equipment, encompassing the entire value chain, including liquefaction, storage, distribution, and end-use. Their equipment exhibits the capability to handle fluctuating flows, accommodating up to 50% of the designed capacity, and can manage a wide range of gas inlet pressures, spanning from 450 to 950 psig. They offer a range of unit sizes, with capacities denominated as 4 (0.03), 8.1 (0.06), 20.3 (0.14), 40.5 (0.28), and 142.9 (1) MMCSFD (MTPA), making them adaptable and modular in nature. The company boasts a presence with multiple operational plants in North America and in various other global regions.

iii) Expansion Energy: Technologies stem largely from the science of cryogenics and the disciplines of natural gas processing and industrial gases production. Among these innovations is the patented methane expansion cycle, known as the VX cycle, which plays a central role. Notably, all preliminary processing steps are seamlessly integrated into the VX cycle, streamlining the overall system. These solutions are both scalable and modular, offering flexibility in unit sizes, ranging from 0.35 to 42 MMSCFD (equivalent to 2500-300,000 MTPA). The company provides diverse options for engagement, including selling, leasing, or licensing these technologies. They have successfully deployed ten VX Cycle LNG plants.

Annexure 4 - GHG Calculation Methodology – Scope 1 & 2

Below is the Scope 1 & 2 Calculation Methodology

Emission Type	Activity Data	Heating Value	Emission Factor	Methodology	Methodology Details
Direct Emissions (Scope-1)	High Speed Diesel Consumption	8000 KCal/L	1. 74.1 Tonnes CO2 /TJ 2. 0.01 Tonnes CH4/TJ 3. 0.0006 Tonnes N20 / TJ	∑ HSD Consumption converted to TJ * Emissions Factor * GWP	Consumed volumes of fuel were converted into TJ by using heating value and multiplied by the published emission factors in the IPCC's Sixth Assessment Report and global warming potential
	Natural Gas Consumption	9000 KCal/SCM	1. 56.1 Tonnes CO2 /TJ 2. 0.005 Tonnes CH4/TJ 3. 0.0001 Tonnes N20 / TJ	∑ Gas Consumption converted to TJ * Emissions Factor * GWP	
	Aviation Turbine Fuel Consumption	8000 KCal/L	1. 71.5 Tonnes CO2 /TJ 2. 0.01 Tonnes CH4/TJ 3. 0.0006 Tonnes N20 / TJ	∑ ATF Consumption converted to TJ * Emissions Factor * GWP	
Indirect Emissions (Scope-2)	Electricity Consumption		0.79 Tonnes CO2 / MWh	Purchased Electricity * Emission factor	Purchased electricity in Million kWh multiplied by emissions factor.

The global warming potential employed in the analysis is as follows

GHG	Global Warming Potential (GWP)
CO2	1
CH4	28
N2O	265

The following conversions apply: 1 BTU equals 252 calories, 1 kilocalorie equals approximately 4 BTUs, and 1 calorie equals 4.18 joules.

Annexure 5 - Requirement of government support

- Accelerate implementation of a compliance carbon market (within three years). This would also require the creation of demand signals, especially in hard-to-abate sectors, and incentives linked to investments in newer technologies like CCUS.
- Enable banks to support the transition, catalysed by a green-transition bank. Banks could be asked to come up with their investment glide paths within one to two years and build the necessary capability for assessing risks in these new spaces.
- Accelerate renewable adoption in the power sector to scale up capacity addition by four times and to deepen market reforms with a 30-year outlook in a manner that ensures a stable grid fed predominantly by infirm power.
- Enhance the National Hydrogen Mission with government playing a key role in accelerating demand through blending mandates, boosting cost competitiveness via capital subsidies and R&D investments, and enabling export opportunities via international trade agreement.

Annexure 6 - Zero routine flaring assumptions

State	Emission Reduction (MM tco2)/year	Capex (Mn INR)	Opex (Mn INR)/year
Gujarat	2.56	91166.52	18.97
Maharashtra	14.48	225322.71	59.61
Tamil Nadu	0.4	14094.28	2.56
Andra Pradesh	0.64	22388.2	4.8
Assam	1.04	30930.2	7.06
Total			

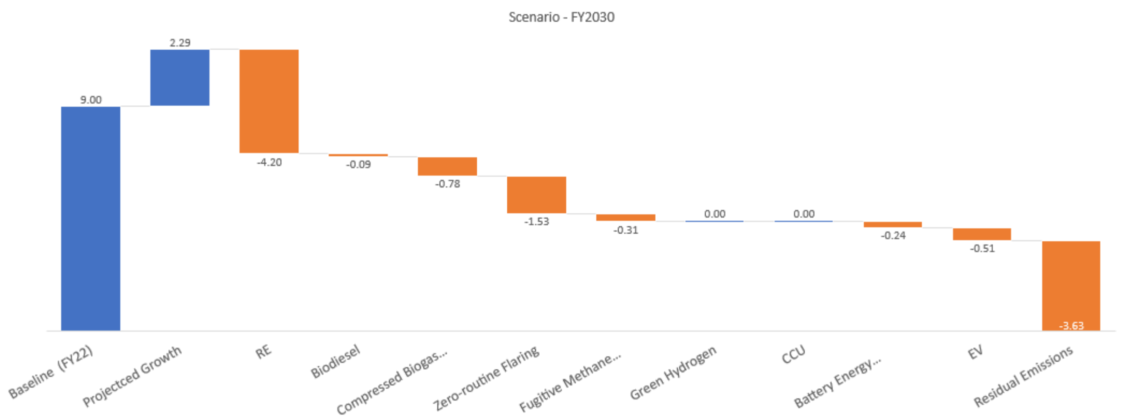
Zero Routine Flaring through technologies		
Project Start Year:	2025	
Service Duration until 2038:	14	years
Carbon Abatement by 2038:	22.92	Mn tCO_2e
Capital Investment:	2,86,117	Mn INR
OpEx Share:		of CapEx
Total OpEx by 2038:	927	Mn INR
Total Revenue by 2038:	11,47,287	Mn INR
Discount rate for NPV:	10%	
NPV of Total Costs:	-15,755	Mn INR

The Above table shows the state-wise emission reduction and CAPEX and OPEX for ZRF.

Annexure 7 - Waterfall diagram for decarbonisation scenarios

Decarbonisation Scenario: 2030

Emissions in Million tCO2e

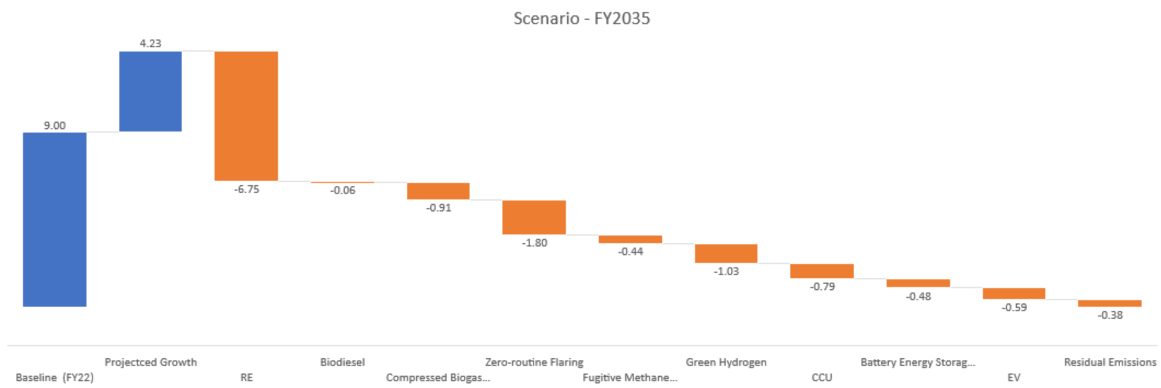


Renewable Energy: 3.89 GW of RE Hybrid, Offshore wind and Small Hydro at Gujarat, Maharashtra, Andhra Pradesh, Tamil Nadu and Assam .

CBG Capacity of 343 MMSCM at Plants and Biodiesel Capacity of 0.170 million Kl

Decarbonisation Scenario: 2035

Emissions in Million tCO2e



5.47 GW of RE Hybrid, Offshore wind and Small Hydro at Gujarat, Maharashtra, Andhra Pradesh, Tamil Nadu and Assam .

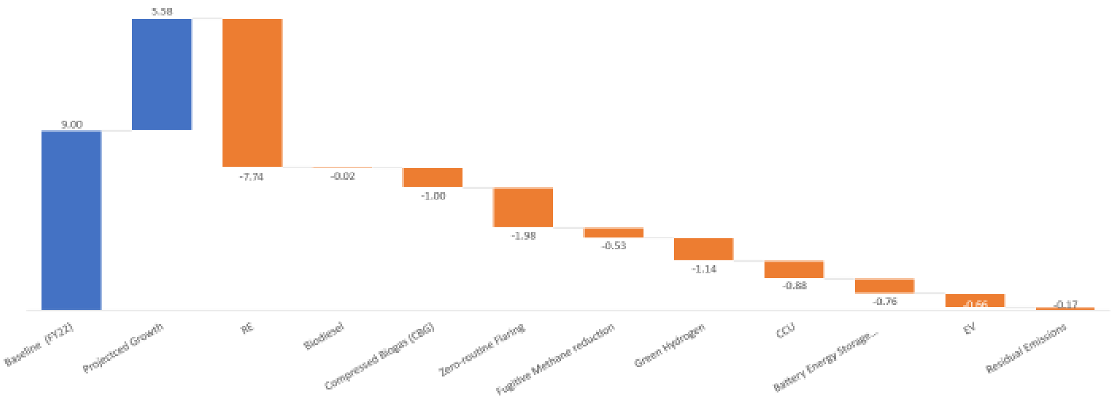
CBG Capacity of 402 MMSCM at Plants and Biodiesel Capacity of 0.12 million kl

Green Hydrogen Capacity of 0.130 million MT in onshore operations

CCU Capacity of 0.79 million tCO2e at Plants

Decarbonisation Scenario: 2038

Emissions in Million tCO2e



6.04 GW of RE Hybrid, Offshore wind and Small Hydro at Gujarat, Maharashtra, Andhra Pradesh, Tamil Nadu and Assam.

CBG Capacity of 444 MMSCM at plants and Biodiesel Capacity of 0.04 million kl

Green Hydrogen Capacity of 0.148 million MT in onshore operations & CCU Capacity of 0.88 million tCO2e at Plants

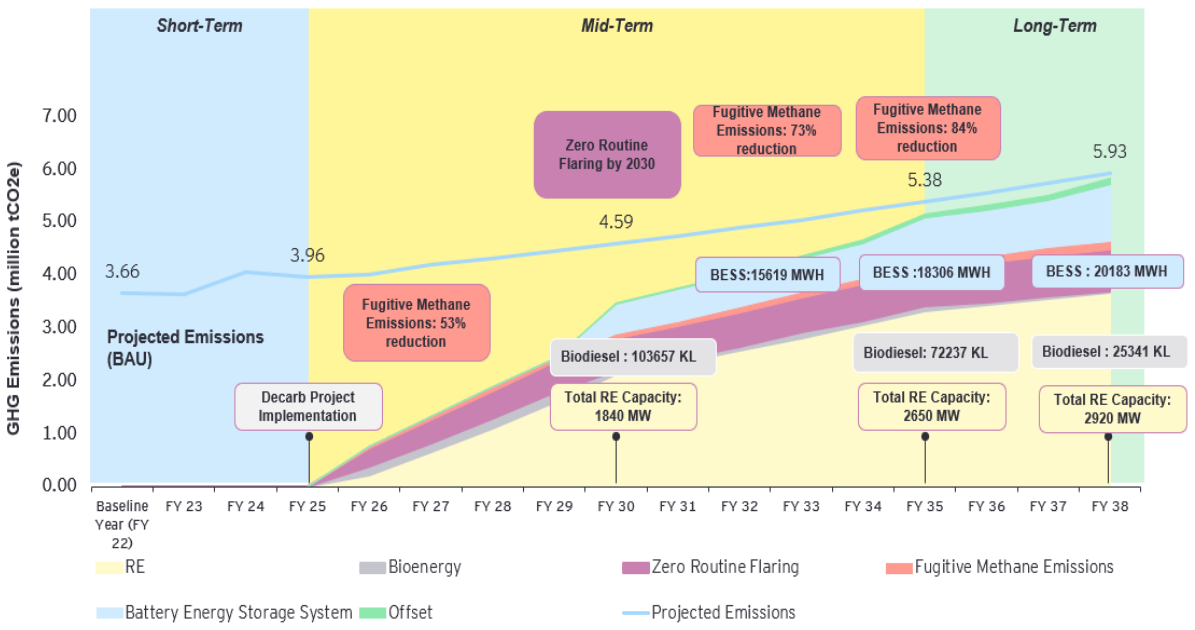
Carbon Offsetting of 0.17 million tCO2e may be achieved either through CCS or Nature based solutions

Annexure 8 - Location wise decarbonisation roadmaps

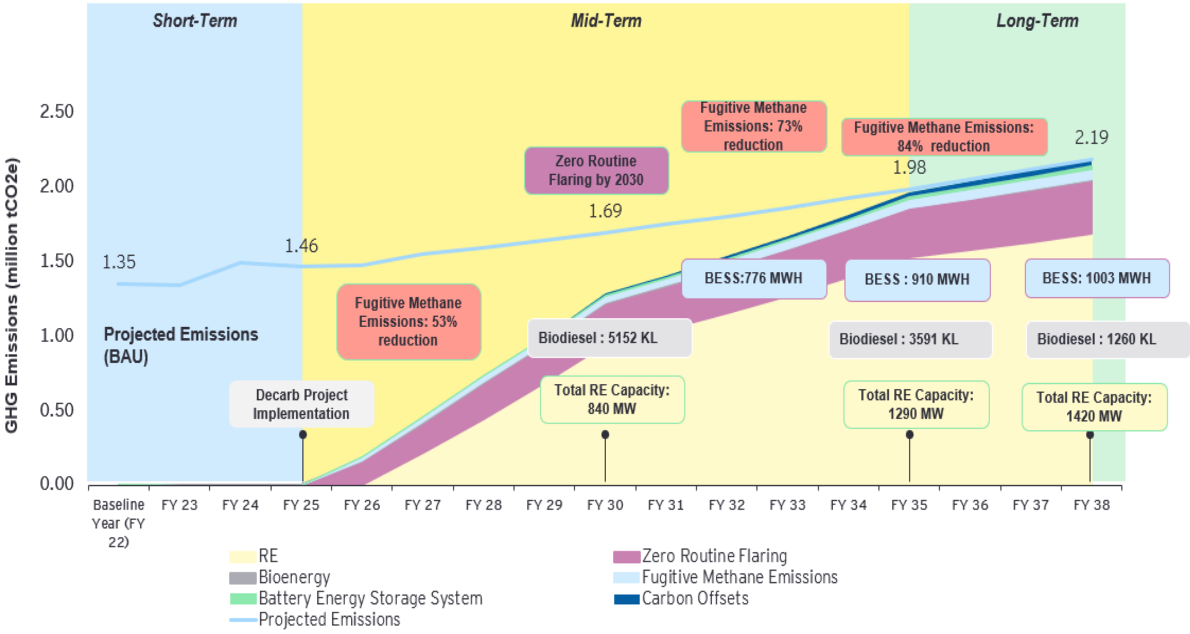
For developing roadmap location wise, consolidated emissions of each asset has been considered which includes services as per the Figure 7.

Offshore Assets		Onshore Assets		Basins		Plants		Institutes	
Scope 1	5.69	Scope 1	1.58	Scope 1	Negligible	Scope 1	1.61	Scope 1	Negligible
Scope 2	0.01	Scope 2	0.12	Scope 2	0.009	Scope 2	0.01	Scope 2	0.0215
Scope 1+ 2	5.70	Scope 1 + 2	1.70	Scope 1 + 2	0.009	Scope 1 + 2	1.62	Scope 1 + 2	0.0215
Mumbai High Asset	3.66	Ankleshwar	0.49	Western offshore &Onshore	0.0041	Hazira plant	0.89	GEOPIC+IDT+KDM IPE+ONGC Academy Dehradun	0.0200
Bassein & Satellite	1.35	Mehsana	0.34	Cauvery Basin	0.0037				
Neelam & Heera	0.55	Assam	0.25	AAFB Exploratory silchar	0.0007	Uran plant	0.64		
Eastern offshore Asset	0.17	Rajahmundry Asset	0.21	Jodhpur Exploratory	0.0004			CEWELL	0.0013
		Jorhat Asset	0.18	Assam &Assam		Dahej Plant	0.08	IPEOT	0.0005
		Ahmedabad Asset	0.17	Arakan basin	0.0003			IPSHEM Goa	0.0002
		Cauvery Asset	0.08	MBA Basin	0.00002				
		Cambay Asset	0.01						
		Tripura Asset	0.009						
		CBM Bokaro Asset	0.004						

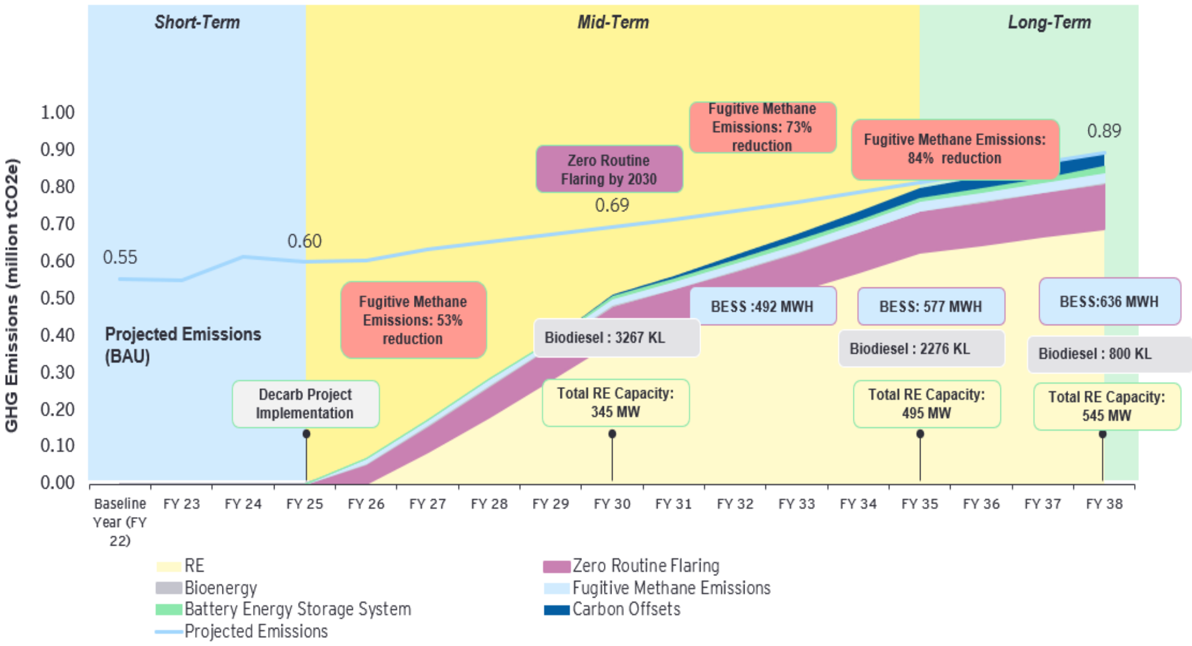
Decarbonization Levers –Mumbai High and Services



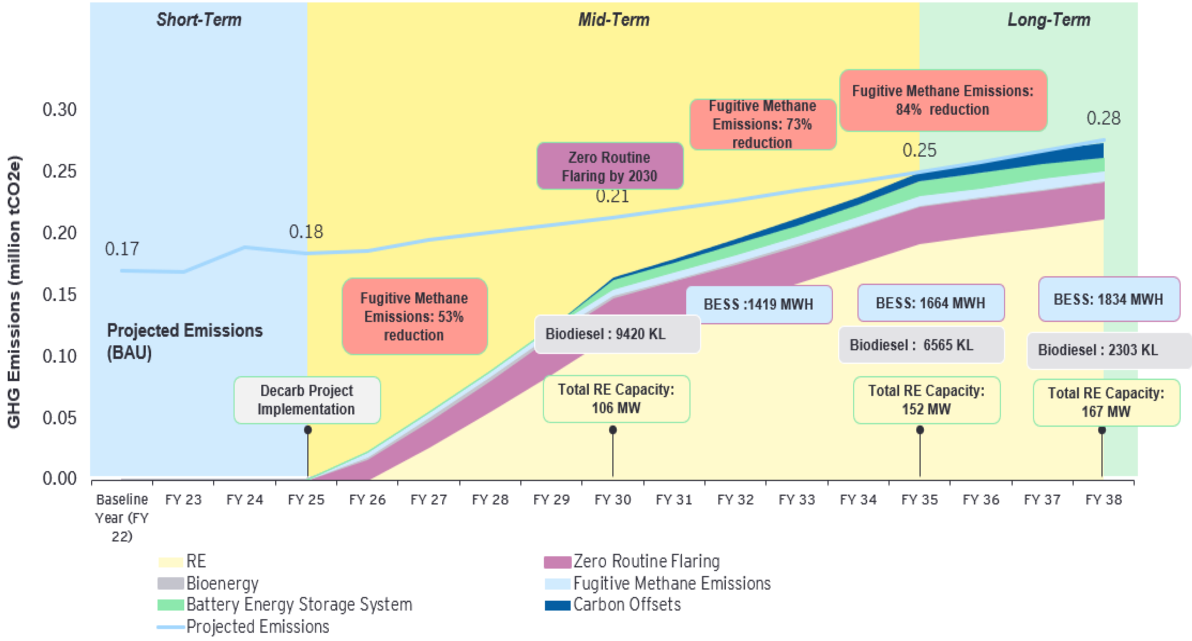
Decarbonization Levers –Bassein & Satellite



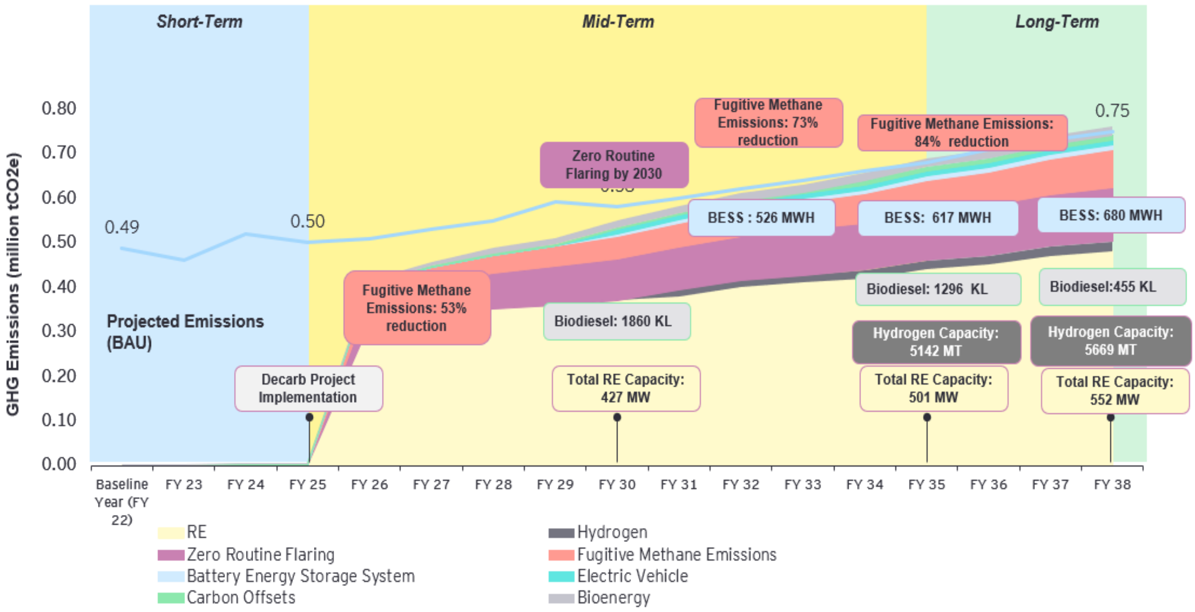
Decarbonization Levers –Neelam & Heera



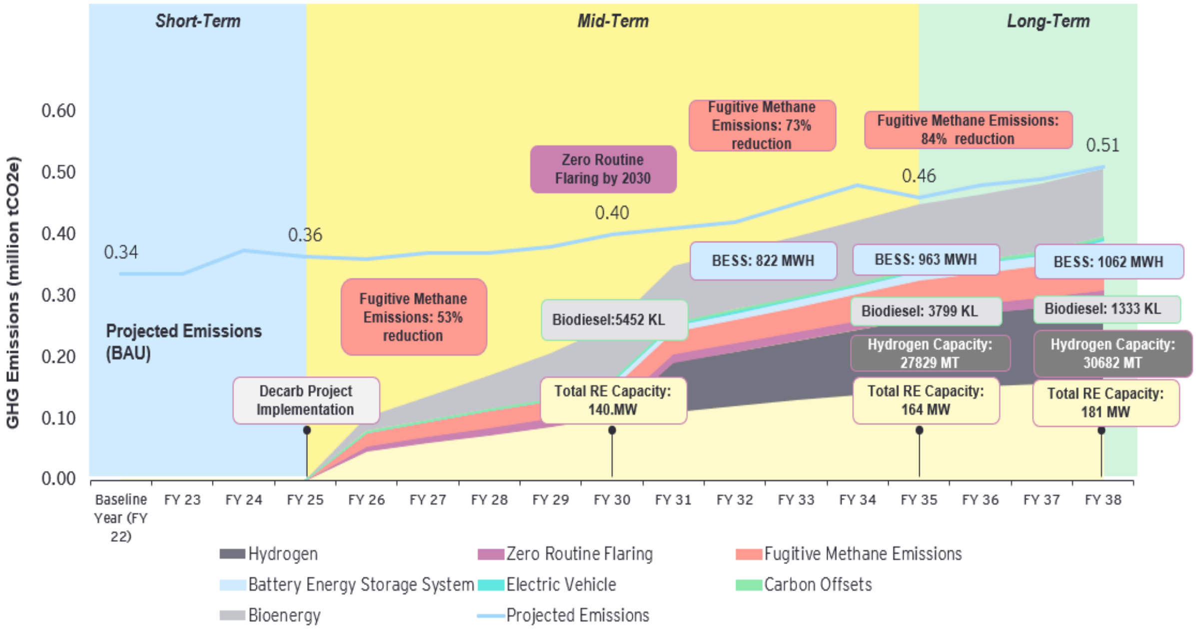
Decarbonization Levers –Eastern Offshore Asset



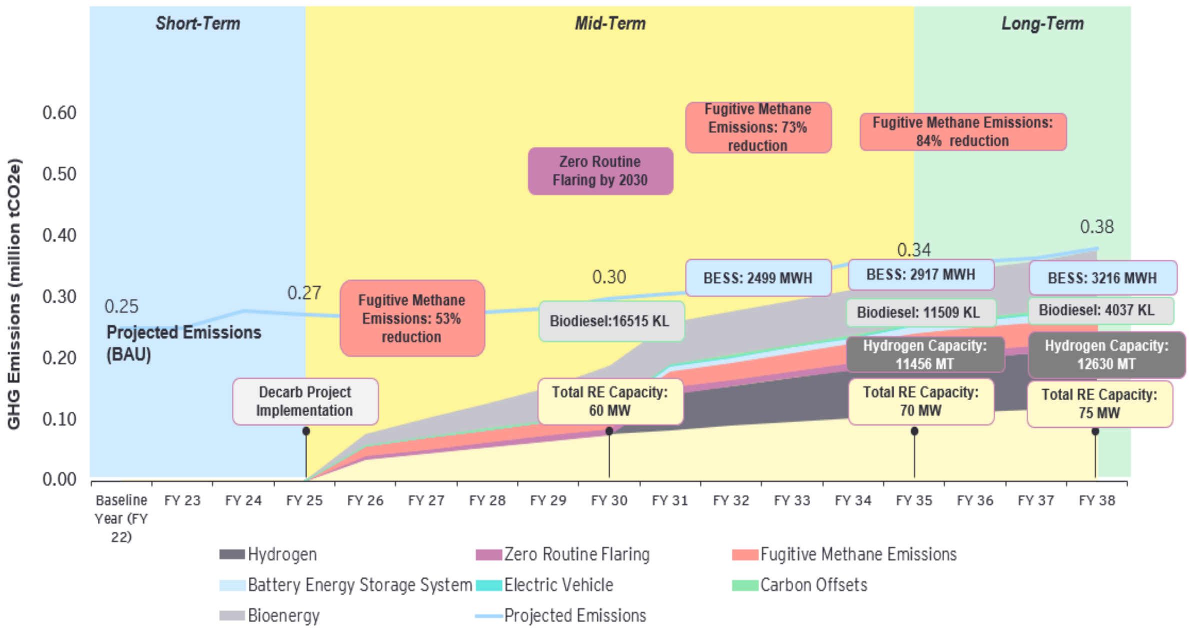
Decarbonization Levers - Ankleshwar



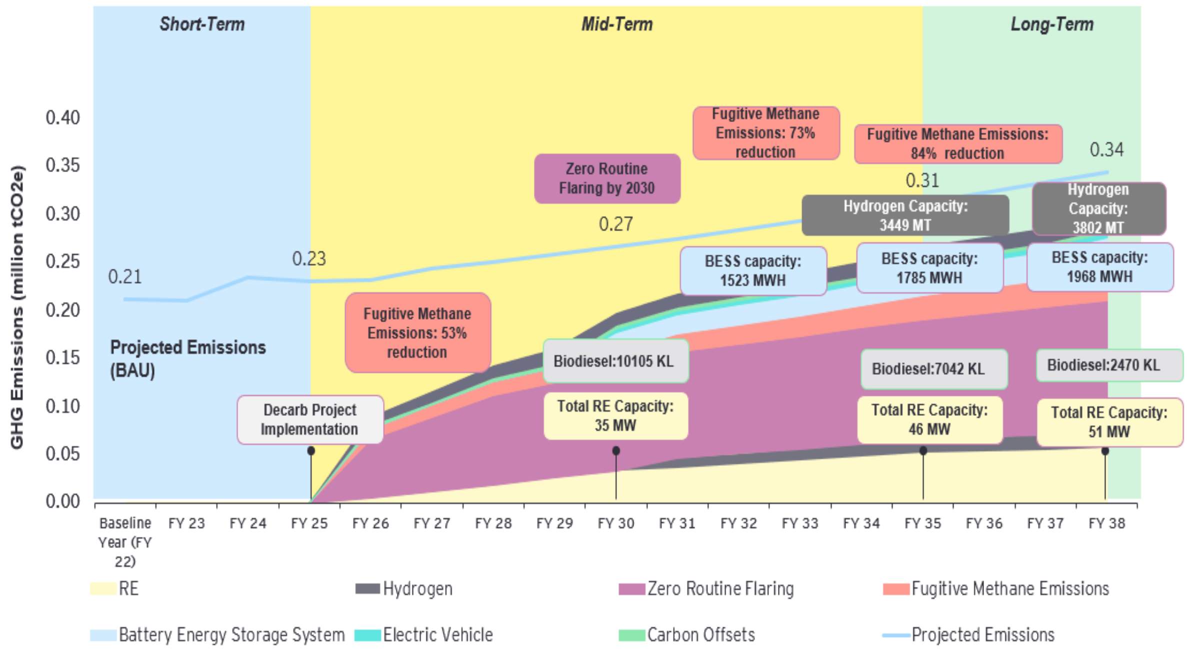
Decarbonization Levers - Mehsana



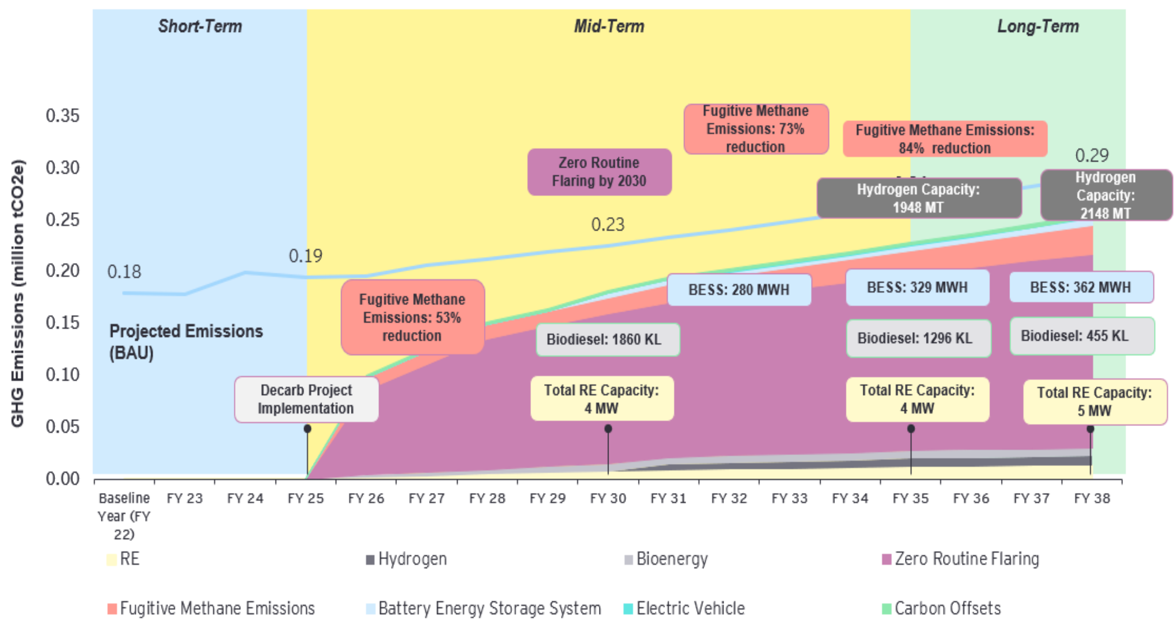
Decarbonization Levers - Assam



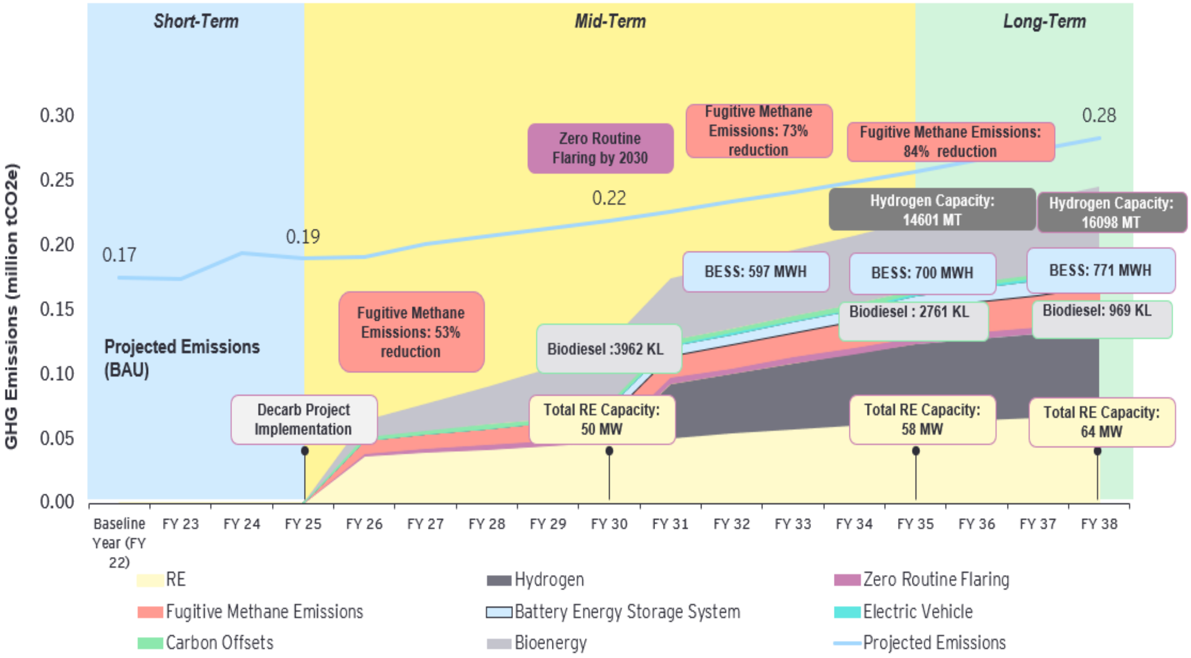
Decarbonization Levers - Rajahmundry



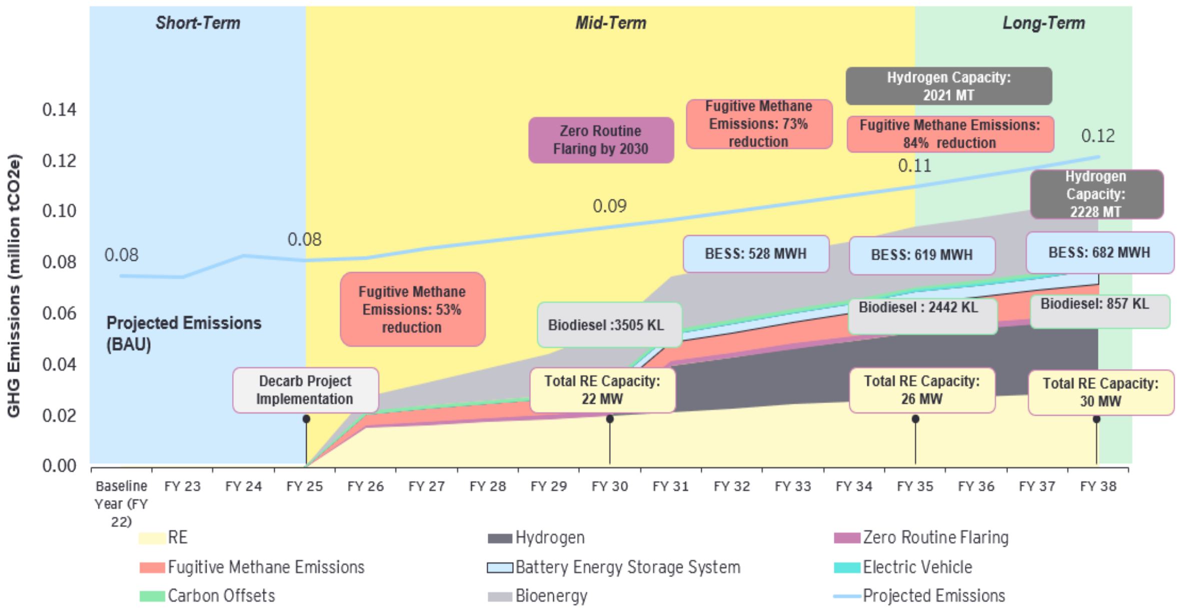
Decarbonization Levers - Jorhat



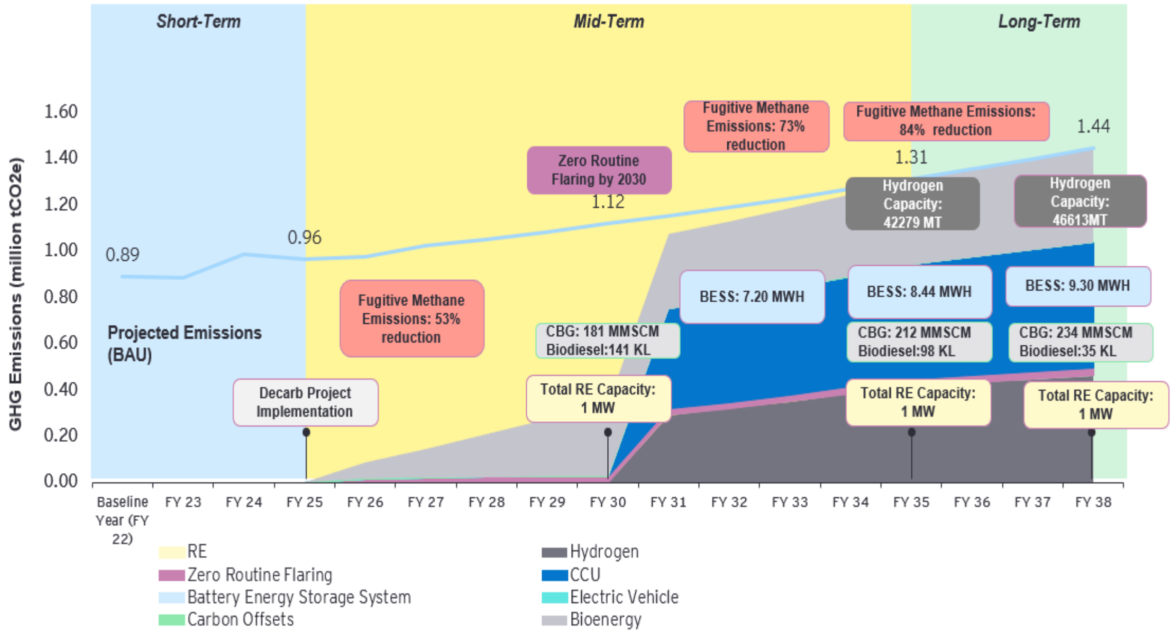
Decarbonization Levers - Ahmedabad



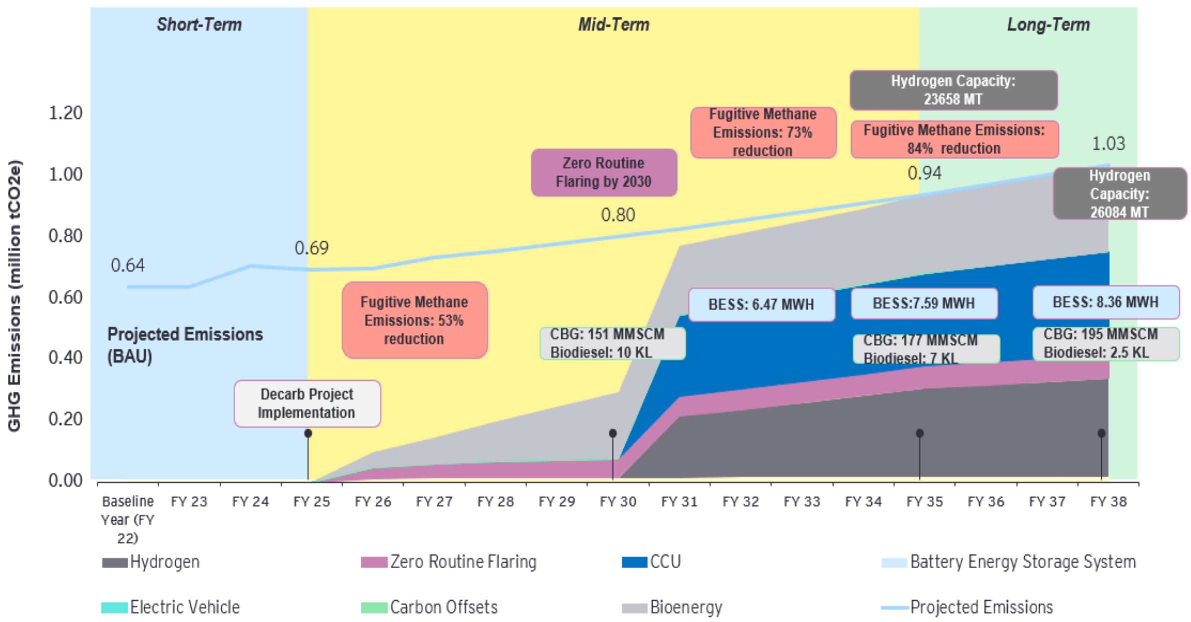
Decarbonization Levers - Cauvery



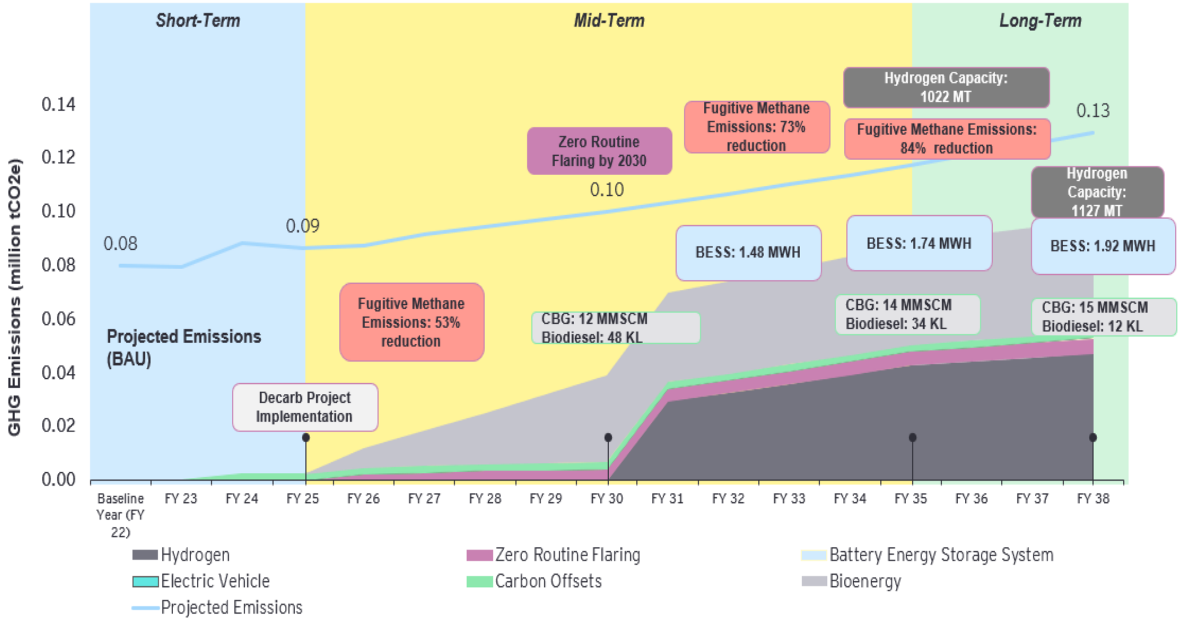
Decarbonization Levers - Hazira



Decarbonization Levers - Uran



Decarbonization Levers - Dahej



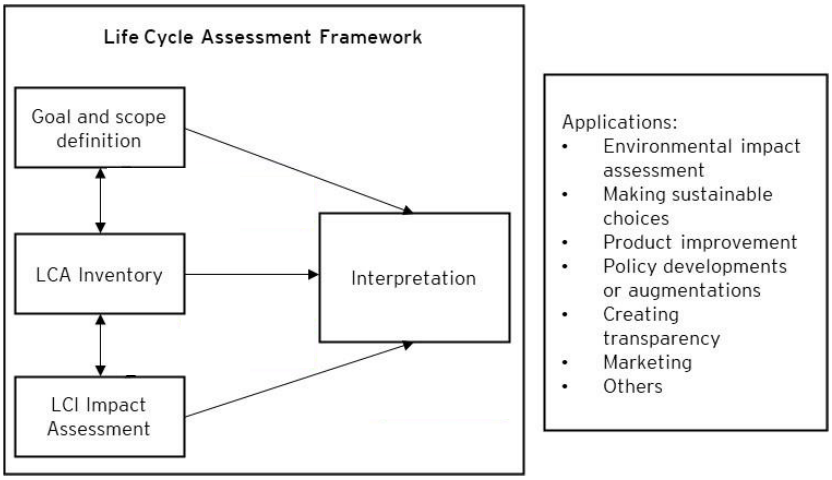
Annexure 9 – Life Cycle Assessment

About LCA

Life Cycle Assessment (LCA) has emerged as a pivotal tool for guiding sustainability decisions across research, industry, and policymaking domains. Renowned for its robustness, LCA enables the quantification of a product or service's diverse environmental impacts throughout its entire life cycle.

By employing a systematic approach that spans from the cradle to the gate or grave, LCA empowers stakeholders to gain profound insights into the genuine repercussions of a product or service. LCA results primarily facilitate product comparisons and pinpoint critical stages within a product's life cycle where environmental impacts are most pronounced. Additionally, this analysis serves as a catalyst, simultaneously capturing the attention of designers, engineers, and management, encouraging them to explore opportunities for improvement. This includes mitigating energy consumption and emissions during raw material sourcing and manufacturing processes, as well as its usage and disposal phases.

Furthermore, it helps stakeholders to discern the tangible distinctions between an environmentally sustainable product and a less sustainable alternative. The calculation and communication of key environmental sustainability metrics enhance an organization's transparency, ultimately persuading consumers to make more responsible choices.



In accordance with the International Organization for Standardization (ISO) 14044/40 standards, LCA typically comprises four key phases, as illustrated in the following figure:

(i) **Goal and scope definition**: This initial phase defines the product system's boundaries and establishes a functional unit. The functional unit is crucial for enabling direct comparisons between alternative goods or services and reference products.

(ii) **Inventory analysis (LCI)**: Life Cycle Inventory (LCI) is the method used to estimate resource usage, waste generation, emissions, and discharges throughout a product's life cycle stages—production, use, and disposal. It models material and energy flows between life cycle processes, providing mass and energy balances for the product system per functional unit.

(iii) **Impact Assessment (LCIA):** LCIA interprets inventory data by providing indicators related to various impact categories. These indicators evaluate a product and its life cycle stages concerning factors like climate change, toxicological stress, eutrophication, noise, land use, and more, often at regional and global scales. LCIA results reflect cumulative contributions across impact categories over time and space.

(iv) **Interpretation:** Interpretation is integrated into each stage of LCA. When comparing two product alternatives, an interpretation based solely on LCI may suffice if one alternative significantly consumes more resources. However, in other cases, comprehensive conclusions may require LCIA, sensitivity analysis, and consideration of the statistical significance of differences in each impact category.

Need for LCA

LCA (Life Cycle Assessment) can be beneficial for Oil and Natural Gas Corporations (ONGC) in several ways with respect to changing regulations, customer preferences, sustainability trends etc.

LCA can help ONGC to understand the environmental impact of their operations across the entire life cycle of oil and gas extraction, production, transportation, and consumption. This assessment allows them to identify and evaluate the potential environmental hotspots and risks associated with their activities. ONGC operate in a highly regulated industry, and LCA helps them meet various environmental regulations and standards imposed by local, national, and international bodies. By quantifying the environmental impacts, ONGC can ensure compliance and avoid penalties or legal issues resulting from non-compliance.

LCA will provide ONGC with comprehensive data on the environmental performance of different products. This information enables informed decision-making regarding resource allocation, technology selection, and strategy development. LCA will help ONGC to identify opportunities for improvement and optimize their operations to minimize environmental impacts. With increased scrutiny on environmental performance and sustainability practices, stakeholders such as investors, customers, and regulatory bodies demand transparency from ONGC. LCA offers a rigorous and standardized methodology to quantify and report environmental impacts, providing stakeholders with transparent information on their operations' sustainability performance LCA will also help ONGC to build and maintain their reputation by demonstrating their commitment to sustainability and responsible environmental practices. Stakeholders, including regulators, communities, NGOs, and investors, increasingly value companies that can show they are actively managing and reducing their environmental impacts. LCA will empowers ONGC to engage with stakeholders, address concerns, and demonstrate their environmental stewardship efforts.

Goal & Scope of the Project

The scope of a Life Cycle Assessment (LCA) to be performed at selected sites covers various major products. These products are integral to the operations of ONGC (Oil and Natural Gas Corporation), and the LCA aims to evaluate the environmental impact associated with the entire life cycle of these products. The major products selected for the LCA include Crude Oil, SKO (Superior Kerosene Oil), LPG (Liquefied Petroleum Gas), Naphtha, C2-C3, and Natural Gas.

The specific coverage of products at different sites is mentioned in below table:

Sites and Products	Bombay High	Neelam	Heera	Bassein & Satellite	Ankleshwar Asset	Uran	Hazira	CTF	CPF	Dahej
Crude Oil										
Gas										
Natural Gas										
C2-C3										
LPG										
Naphtha										
ATF										
Kerosene										
Diesel										
Ethane										
Propane										
Butane										

Table: Product mapping with production and processing facilities

Overall approach to the Project

The ONGC (Oil and Natural Gas Corporation) initiated a Life Cycle Assessment (LCA) study with the primary objective of assessing the carbon footprint associated with its major products. The focus of the study encompasses a range of significant energy products, including Crude Oil, Natural Gas, SKO (Superior Kerosene Oil), LPG (Liquefied Petroleum Gas), Naphtha, and C2-C3. This comprehensive evaluation is aimed at understanding and quantifying the environmental impact of each stage of these products' life cycles.

To facilitate the modelling and analysis of the inventory data for the financial year 2021-22, the OpenLCA software was employed. OpenLCA is a widely used tool for life cycle assessment, allowing for the systematic and detailed modelling of processes and their associated environmental impacts.

The inventory data considered in the study is extensive, covering all unit processes related to both offshore and onshore assets, as well as associated plants. Each unit process includes input feeds, output products, and utility inputs. This level of granularity ensures that the LCA study captures a comprehensive picture of the environmental implications associated with the entire life cycle of ONGC's products.

In terms of the allocation procedure used for attributing emissions to specific processes, a Physical – Mass based allocation procedure was applied. This approach involves distributing emissions based on the mass of the products involved in each unit process. It is a method commonly used in LCAs to fairly distribute environmental burdens among different products.

The results of the LCA study are presented in terms of four impact categories, namely:

- Acidification: This category assesses the potential for a substance to contribute to acid rain or acidification of the environment.
- Climate Change: Evaluates the contribution of the studied processes to global warming potential, often measured in terms of carbon dioxide equivalents.
- Marine Eutrophication: Focuses specifically on the impact of nutrient enrichment in marine ecosystems.
- Fresh Eutrophication: Focuses specifically on the impact of nutrient enrichment in freshwater ecosystems.

The detailed explanation of these impact categories is provided in a further section of the report, likely offering insights into how each product and associated process contributes to these environmental impacts. This comprehensive approach to LCA enables ONGC to make informed decisions and implement strategies to minimize the environmental footprint of its operations and products.

For this LCA study, emissions factors are taken from Secondary Database and Ecoinvent 3.9.1. Moreover, software used for the study is OpenLCA 1.11.

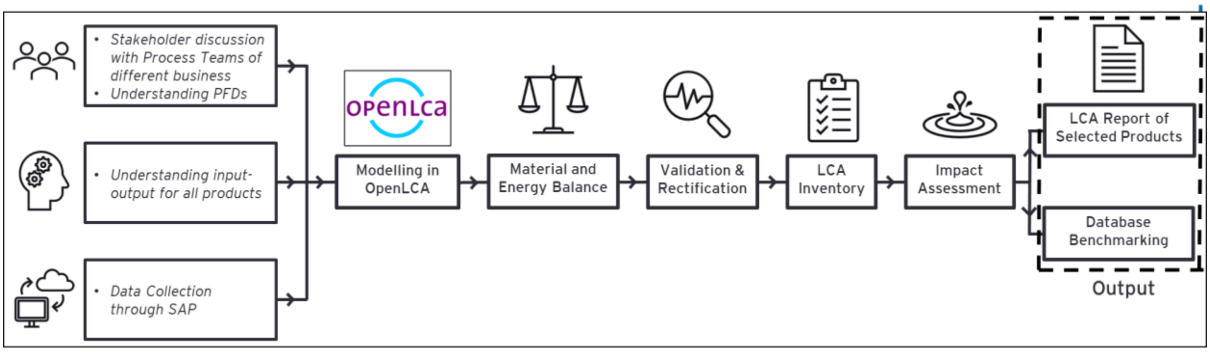


Figure: Project Working Flow

Functional Unit

In a Life Cycle Assessment (LCA) study, a functional unit is a fundamental concept used to define and quantify the function that a product or service provides to its intended user. The functional unit serves as a standardized reference point for comparing the environmental impacts of different products or services that deliver the same function. By establishing a common basis for comparison, the LCA study can facilitate meaningful evaluations and comparisons of the environmental performance of various alternatives.

There are three main types of functional units employed in LCA studies:

Reference Unit:

The reference unit is a functional unit that quantifies the basic function of the product or service. It is often expressed in physical terms, such as weight, volume, or energy content. The reference unit serves as a baseline for comparing different products based on their ability to fulfil a specified function.

Performance Unit:

The performance unit is a functional unit that focuses on the effectiveness or efficiency of a product or service in delivering its intended function. This type of functional unit considers the performance aspects of the product. Performance units are particularly useful when the primary goal is to assess how well a product performs in achieving its intended purpose.

Economic Unit:

The economic unit is a functional unit that is expressed in economic terms, such as cost or monetary value. This type of functional unit is valuable when economic considerations are significant in the decision-making process. It allows for the comparison of the environmental impacts of different products based on their economic value, providing insights into the environmental efficiency of various economic choices.

The choice of the appropriate functional unit depends on the specific goals and context of the LCA study. Each type of functional unit provides a unique perspective on the environmental impact of a product or service, allowing for a more comprehensive understanding of its sustainability performance.

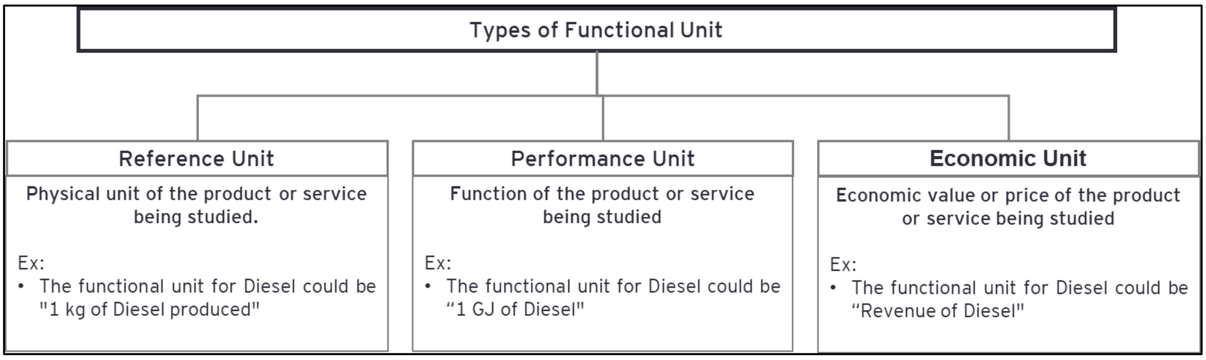


Figure: Type of functional unit in LCA

For ONGC LCA study the functional unit has been defined based on the goal and scope of the study from the beginning, which is based on the production quantity of the products from production and processing plants. In order to normalise the assessment for final products the functional unit for the impact measurement is considered Per Kilogram of the final product i.e., ($KgCO_2$eq./Kg of Product) for financial year 2021-22. Physical mass-based allocation has been used for the LCA study of final products from processing plants. To better understand allocation types and physical mass-based allocation figure is illustrated in the figure.

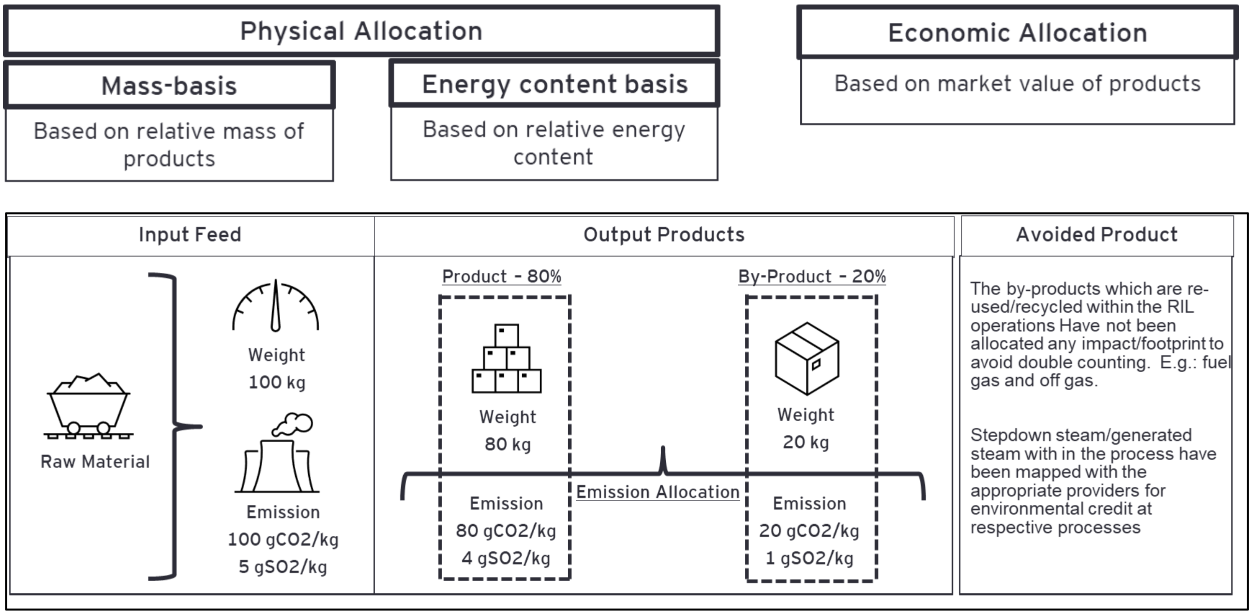


Figure: Illustration of physical mass-based allocation

LCIA Methodology

An environmental footprint, particularly when assessed through mid-point indicators, serves as a comprehensive metric to gauge the overall environmental impact of a product, process, or activity across its entire life cycle. This life cycle encompasses all stages, starting from the extraction of raw materials to the eventual disposal or recycling of the product.

Various dimensions of environmental footprints exist, each targeting a specific aspect of environmental impact. Prominent examples include the carbon footprint, which measures the amount of greenhouse gases emitted, the water footprint, which assesses water usage, and the ecological footprint, which gauges the demand and supply of ecological resources.

Mid-point indicators, within the broader context of environmental impact assessment, are analytical tools designed to numerically represent potential environmental consequences. These indicators quantify the projected impacts on specific environmental categories, such as climate change, acidification, eutrophication (excessive nutrient levels in water bodies), and human toxicity etc. The derivation of mid-point indicators involves scientific models that establish a link between emissions or inputs and their corresponding environmental impacts.

The significance of mid-point indicators lies in their ability to provide a quantifiable measure of potential environmental impacts. This quantitative data allows for a comparative analysis of different products, processes, or activities, aiding in decision-making processes. Through such comparisons, stakeholders can identify areas that contribute significantly to environmental degradation, guiding efforts for improvement and sustainability.

Impact Categories

Climate Change (GWP)

- Evaluates the potential of a product to contribute to climate change by releasing Greenhouse Gases (GHGs).
- Significance- By relating product's GHG emissions with its equivalent CO2 impact over 100 years Contributors- GHGs

Acidification Potential (AP)

- Evaluates the potential contribution of a product towards acid rain
- Contributors-(SO2) and Nitrogen oxides (NOx).

Marine Eutrophication Potential (MEP)

- Evaluates product's potential to contribute to nutrient enrichment into marine bodies, which leads to growth of algae and other aquatic plants.
- Contributors- Nitrogen containing compounds
- Impact- Hypoxic condition due to decomposition of algae causing aquatic life imbalance

Freshwater Eutrophication Potential (FEP)

- Evaluates product's potential to contribute to nutrient enrichment into freshwater bodies, which leads to growth of algae and other aquatic plants.
- Contributors- Nitrogen & Phosphorus containing compounds
- Impact- Hypoxic condition due to decomposition of algae causing aquatic life imbalance

Figure: Impact categories for ONGC

Basis and Assumptions

The LCA study relies on the following basis and assumptions:

1. Electricity and steam emission factors required for the URAN plant are obtained directly from the database.
2. The LCA study considers the thermal energy for Diesel and Natural Gas from database for all production and processing facilities.
3. In the study, the natural gas utilized for gas lift operations is categorized as avoided emissions.
4. Instrument air, and nitrogen consumption is distributed as per percentage of input material for Uran plant
5. Steam consumption is distributed across units as per unit process norms for Uran plant

Limitations:

The LCA study is limited in the geographical region of India.

- Offshore Asset – Mumbai High, Neelam & Heera, Bassein & Satellite
- Onshore Asset – Ankleshwar (CPF and CTF)
- Plants – Uran, Hazira, C2-C3

Secondary database has been considered for products coming from outside of the operating boundary. Results are/may be affected by factors that differ by geographic region, electricity grid mix, transportation, and waste management practices.

The limitation of this LCA study lies in the fact that, system expansion method is used for production and processing facilities where information on unit-wise operation was not available. Specifically, all the offshore and onshore asset are modelled according to system expansion and plants such as Hazira, C2-C3 are modelled by system expansion method.

The emission factors for the following chemicals are used in the production and processing facilities are taken from EU region database.

Aluminium sulphate, Copper electrolyte, Sodium sulphite, Methanol, Amines, Tri Ethylene Glycol,

Interpretation:

The LCA study results are analysed and discussed based on the following points:

Identification of significant impacts categories: All the applicable impact categories have been identified pertaining to the business operations and mentioned under impact category section of the report.

Result benchmarking: The LCA study results are benchmarked against available India database and global database. (Database Source – ecoinvent 3.9.1).

Data Quality:

Data quality is a paramount consideration in the context of Life Cycle Assessment (LCA), as the precision and dependability of the data employed exert a substantial influence on the outcomes and interpretations of the study. In the pursuit of a comprehensive and accurate evaluation of the environmental impacts associated with a product, process, or activity throughout its entire life cycle, specific data quality requirements are imperative. These requirements play a crucial role in ensuring the credibility and robustness of LCA findings.

The following are key considerations in maintaining data quality for an LCA study:

- Time coverage:
    - Financial Year 2021-22
- Geographical coverage:
    - Offshore – Mumbai High, Neelam & Heera, Bassein & Satellite
    - Onshore – Ankleshwar, CPF, CTF
    - Plants – Uran, Hazira and C2-C3
- Data source:
    - SAP database
- Representativeness:
    - Three offshore assets, one onshore asset, and three plants were considered for modelling.

The above-mentioned production and processing facilities were undertaken for due to the following grounds:

a. Majority of the production (>70%) of ONGC comes from Offshore platform, namely, Mumbai High, Neelam & Heera and Bassein & Satellite.
b. Selected processing plants cover all the major products, namely, Crude Oil, Natural Gas, C2, C3, C4, Naphtha, LPG, ATF, Kerosene, Diesel.
c. Selected production and processing facilities covers majority of the GHG emissions (>75%).

- Precision:
    - Actual inventory data as per SAP database which captures data in accurate and timely manner
- Information uncertainty:
    - Data is provided for FY 2021-22 irrespective of any fluctuations or upsets in the system or processes by the processing and production facilities.
- Consistency:
    - Data for 12 consecutive months (FY 2021-22) have been considered for the study that takes care of seasonal fluctuations

LCA Result

1. Mumbai High, Neelam & Heera, and Uran

Function	Site	Product	Impact Categories			
			Climate Change (kgCo2eq)	Acidification (mol H+ eq)	Eutrophication Marine (kg N eq)	Eutrophication Freshwater (kg P eq)
Production	Mumbai High	Crude Oil	0.202	0.0002	0.0001	7.6E-08
		Gas	0.202	0.0002	0.0001	7.6E-08
Production	Heera	Crude Oil	0.222	0.0003	0.0001	2.18E-08
		Gas	0.222	0.0003	0.0001	2.18E-08
Production	Neelam	Crude Oil	0.392	0.0005	0.0002	1.28E-07
		Gas	0.392	0.0005	0.0002	1.28E-07
Production	Consolidated (MH + Heera + Neelam)	Crude Oil	0.22	0.0002	0.0001	6.98E-08
		Gas	0.199	0.0002	0.0001	7.08E-08
Processing	**URAN**	**Crude Oil**	**0.258**	**0.0003**	**0.0001**	**7.85E-08**
		Natural Gas	**0.892**	**0.0012**	**0.0005**	**6.65E-08**
		C2-C3 Mix	**0.892**	**0.0012**	**0.0005**	**6.65E-08**
		LPG	**0.811**	**0.0011**	**0.0004**	**5.9E-08**
		Naphtha	**0.578**	**0.0007**	**0.0002**	**7.88E-08**

2. Bassein & Satellite, and Hazira

Function	Site	Product	Impact Categories			
			Climate Change (kgCo2eq)	Acidification (mol H+ eq)	Eutrophication Marine (kg N eq)	Eutrophication Freshwater (kg P eq)
Production	Bassein & Satellite	Crude Oil	0.216	0.0002	0.000095	2.51E-08
		Gas	0.216	0.0002	0.000095	2.51E-08
Processing	**Hazira**	**ATF**	**0.463**	**0.0005**	**0.0002**	**7.17E-08**
		Diesel	**0.463**	**0.0005**	**0.0002**	**7.17E-08**
		Natural Gas	**0.889**	**0.0013**	**0.0005**	**1.08E-07**
		Kerosene	**0.463**	**0.0005**	**0.0002**	**7.17E-08**
		LPG	**0.889**	**0.0013**	**0.0005**	**1.08E-07**

		Naphtha	0.463	0.0005	0.0002	7.17E-08
		C3 (Propane)	0.463	0.0005	0.0002	7.17E-08

3. Ankleshwar, CTF, and CPF

Function	Site	Product	Impact Categories			
			Climate Change (kgCo2eq)	Acidification (mol H+ eq)	Eutrophication Marine (kg N eq)	Eutrophication Freshwater (kg P eq)
Production	Ankleshwar	Crude Oil	0.507	0.0007	0.0002	4.43E-08
		Gas	0.507	0.0007	0.0002	4.43E-08
Processing	CPF	Crude Oil	0.579	0.0008	0.0003	6.10E-08
		Natural Gas	0.712	0.001	0.0004	5.60E-08
		LPG	0.712	0.001	0.0004	5.60E-08
		Naphtha	0.712	0.001	0.0004	5.60E-08
Processing	CTF	Crude Oil	0.579	0.0008	0.0003	6.10E-08
		Natural gas	0.614	0.0009	0.0003	6.04E-08
		LPG	0.614	0.0009	0.0003	6.04E-08
		Naphtha	0.614	0.0009	0.0003	6.04E-08

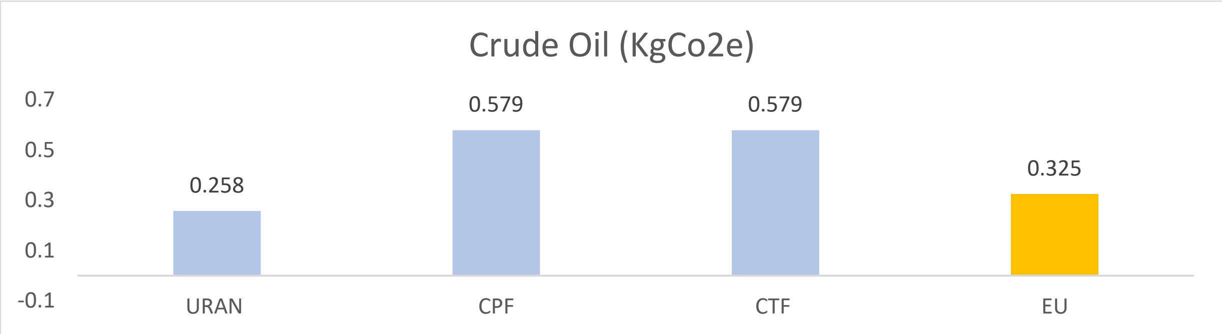
4. C2-C3 Dahej

Function	Site	Product	Impact Categories			
			Climate Change (kgCo2eq)	Acidification (mol H+ eq)	Eutrophication Marine (kg N eq)	Eutrophication Freshwater (kg P eq)
Processing	C2-C3	LPG	0.233	0.002	0.0002	7.39E-08
		C2 (Ethane)	0.233	0.002	0.0002	7.39E-08
		C3 (Propane)	0.233	0.002	0.0002	7.39E-08
		C4 (Butane)	0.233	0.002	0.0002	7.39E-08

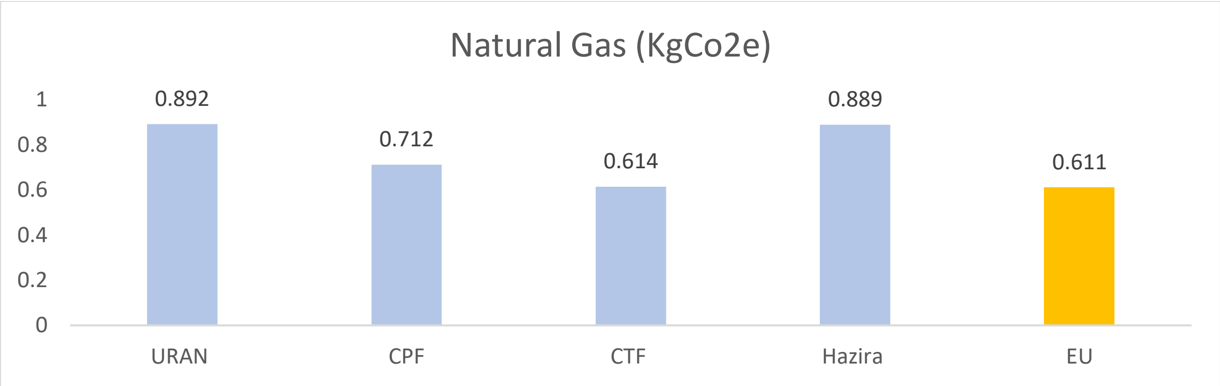
Benchmarking of Products

Benchmarking of products are done on the impact category of "Climate Change - KgCO2eq/Kg of Product."

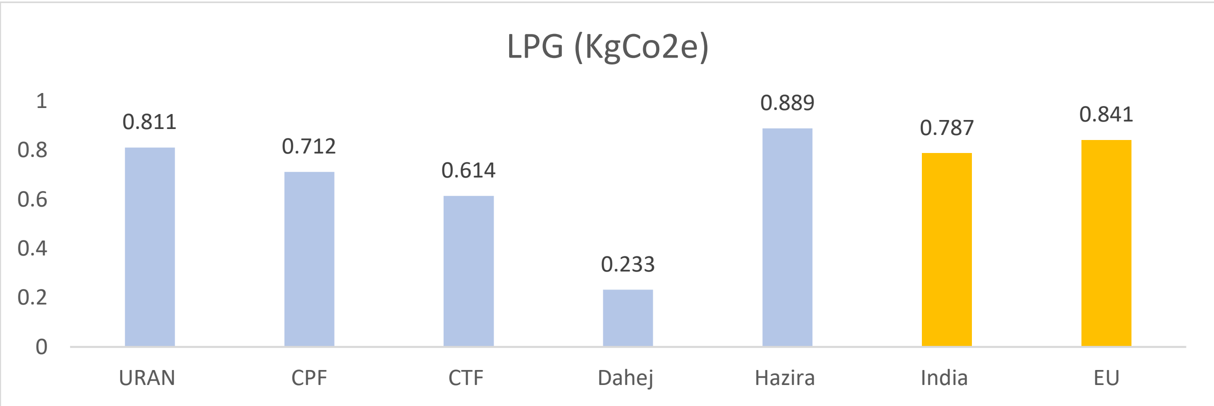
8. Crude Oil



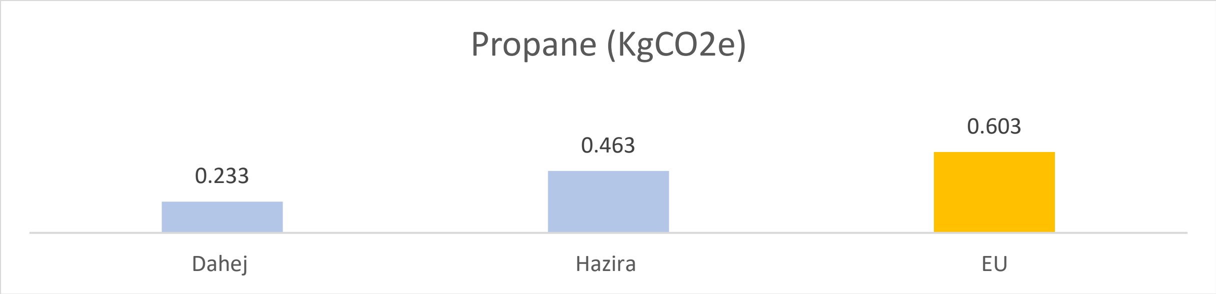
9. Natural Gas



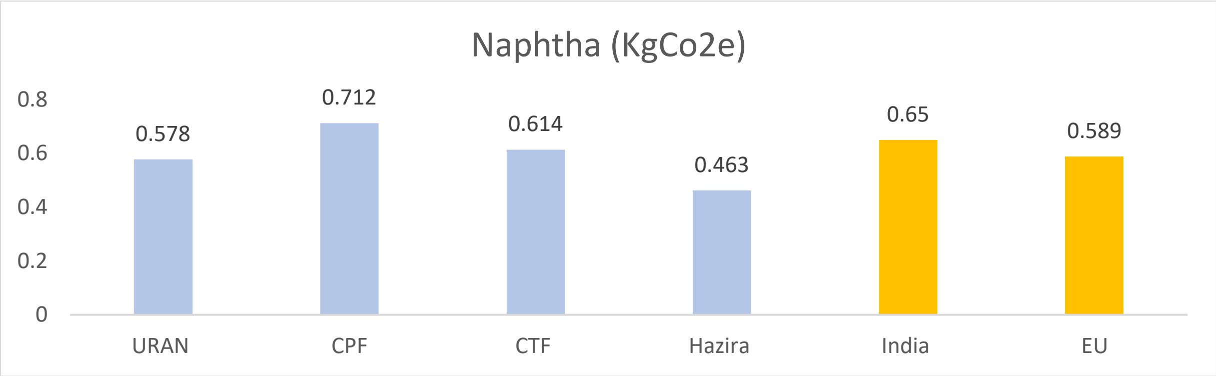
10. LPG



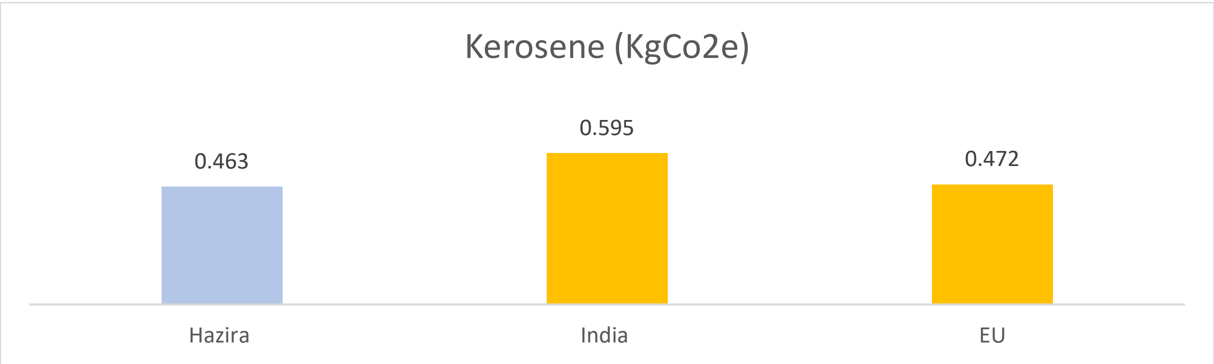
11. C3 (Propane)



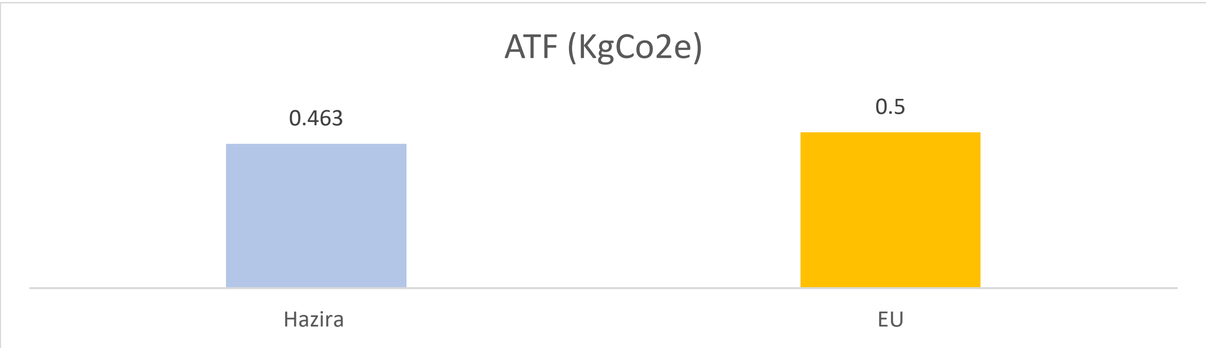
12. Naphtha



13. Kerosene



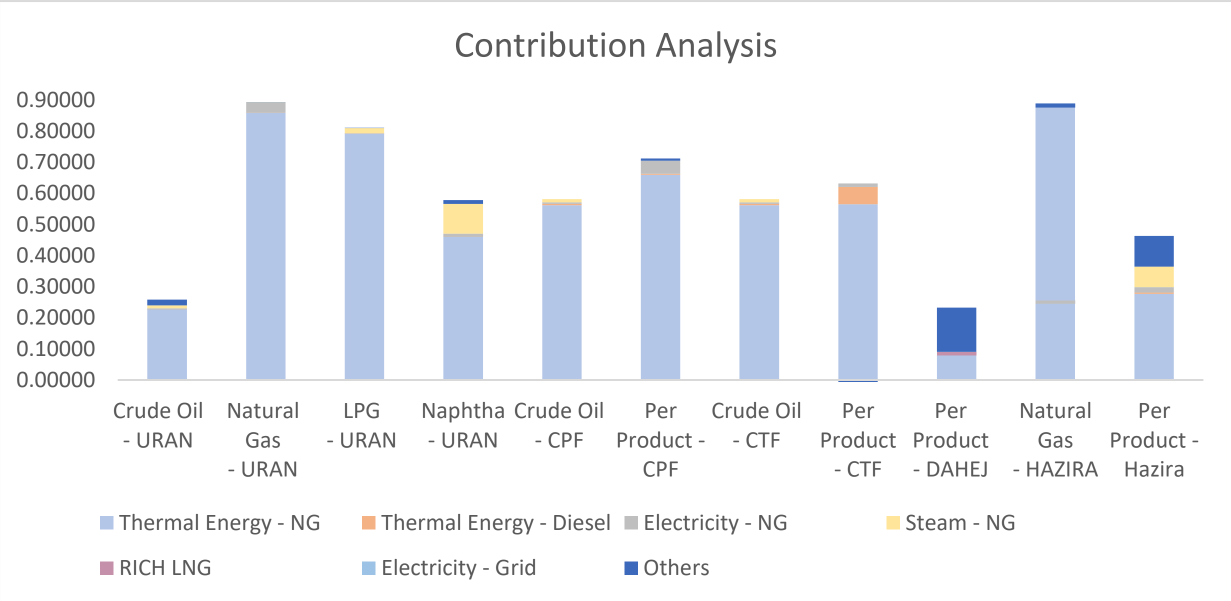
14. ATF



Contribution Analysis

The contribution analysis in the Life Cycle Assessment (LCA) study reveals the sources of emissions within each product category. This means that the study identifies and assesses which factors or components are responsible for generating emissions within specific product groups.

The GHG emissions contribution as "KgCO_2eq. per Kg of Product" from the each of the processing facilities are outlined in the below graph and table.



Annexure 10 - Calculations

Summary

#	Lever	Start Year (FY)	Capacity by FY 2038	Abatement Potential (Mn tCO_2e)	CAPEX (Mn INR)	Total OPEX (Mn INR)	NPV of Total Costs (Mn INR)	Implicit Price (USD/tCO_2e)
1	RE Hybrid	2026	4145 MW	54.4	2,30,937	40,906	2,31,280	51
2	Offshore Wind	2027	1805 MW	39.8	2,49,120	39,653	2,49,097	75
3	Small Hydro	2031	85 MW	1.8	8,030	1,917	8,924	58
4	Biodiesel	2026	3 Mn kL	1.5	24,447	4,400	26,313	205
5	Compressed Biogas (CBG)	2026	4,205 MMSCM	10.6	45,195	91,192	71,610	81
6	Zero-routine Flaring	2025		20.5	35,765	116	35,795	21
7	Fugitive Methane reduction*	2025		4.8				
8	Green Hydrogen**	2031	1 Mn MT	7.6	36,957		36,957	59
9	CCUS	2031		6.3	62,449	17,890	70,795	136
10	Battery Energy Storage System (BESS)	2030		0.1	506	167	577	102
Overall Implicit Carbon Price					6,93,406	1,96,242	7,31,349	59.80

RE Hybrid

2038 Projections

State	Renewable Lever	Projected Capacity (in MW)	CAPEX (in Mn INR)	OPEX (in Mn INR)	Emission Reduction (in Mn tCO2e)	Savings (in Mn INR/ Annum)	Payback (Years)
Gujarat	RE- Hybrid	801.6	44651.4	446.5	0.74	5025.0	8-9
Maharashtra	RE- Hybrid	3120.6	414835.3	2788.4	6.46	32058.0	9-10
	Offshore Wind	1759.0					
Tamil Nadu	RE- Hybrid	28.4	1620.5	16.2	0.02	151.7	10-11
Andhra Pradesh	RE- Hybrid	194.7	18950.0	189.5	0.28	1777.4	8-9
	Offshore Wind	46.3					
Assam	Small Hydro	84.6	8029.6	200.7	0.23	711.8	11-12
Total		6035.23	488086.8	3641.3	7.73	39723.8	

RE Hybrid - Wind (70%) - Solar (30%)		
Capacity by 2030:	4,145	MW
Project Start Year:	2026	FY
Service Duration until 2038:	13	years
Carbon Abatement by 2038:	**54.35**	Mn tCO_2e
Capital Investment:	2,30,937	Mn INR
OpEx Share:	1%	of CapEx
OpEx Escalation Y-o-Y:	5%	assumed
Total OpEx by 2038:	40,906	Mn INR
Discount rate for NPV:	10%	assumed
NPV of Total Costs:	**2,31,280**	**Mn INR**

Offshore wind

2038 projections :

State	Renewable Lever	Projected Capacity (in MW)	CAPEX (in Mn INR)	OPEX (in Mn INR)	Emission Reduction (in Mn tCO2e)	Savings (in Mn INR/ Annum)	Payback (Years)
Gujarat	RE-Hybrid	801.6	44651.4	446.5	0.74	5025.0	8-9
Maharashtra	RE-Hybrid	3120.6	414835.3	2788.4	6.46	32058.0	9-10
	Offshore Wind	1759.0					
Tamil Nadu	RE-Hybrid	28.4	1620.5	16.2	0.02	151.7	10-11
Andhra Pradesh	RE-Hybrid	194.7	18950.0	189.5	0.28	1777.4	8-9
	Offshore Wind	46.3					
Assam	Small Hydro	84.6	8029.6	200.7	0.23	711.8	11-12
Total		6035.23	488086.8	3641.3	7.73	39723.8	

Offshore Wind		
Capacity by 2038:	1,805	MW
Project Start Year:	2027	FY
Service Duration until 2038:	12	years
Carbon Abatement by 2038:	**39.83**	Mn tCO_2e
Capital Investment:	2,49,120	Mn INR
OpEx Share:	1%	of CapEx
OpEx Escalation Y-o-Y:	5%	assumed
Total OpEx by 2038:	39,653	Mn INR
Discount rate for NPV:	10%	assumed
NPV of Total Costs:	**2,49,097**	**Mn INR**

Small Hydro

State	Renewable Lever	Projected Capacity (in MW)	CAPEX (in Mn INR)	OPEX (in Mn INR)	Emission Reduction (in Mn tCO2e)	Savings (in Mn INR/ Annum)	Payback (Years)
Gujarat	RE- Hybrid	801.6	44651.4	446.5	0.74	5025.0	8-9
Maharashtra	RE- Hybrid	3120.6	414835.3	2788.4	6.46	32058.0	9-10
	Offshore Wind	1759.0					
Tamil Nadu	RE- Hybrid	28.4	1620.5	16.2	0.02	151.7	10-11
Andhra Pradesh	RE- Hybrid	194.7	18950.0	189.5	0.28	1777.4	8-9
	Offshore Wind	46.3					
Assam	Small Hydro	84.6	8029.6	200.7	0.23	711.8	11-12
Total		6035.23	488086.8	3641.3	7.73	39723.8	

Small Hydro		
Capacity by 2030:	85	MW
Project Start Year:	2031	FY
Service Duration until 2038:	8	years
Carbon Abatement by 2038:	**1.84**	Mn tCO_2e
Capital Investment:	8,030	Mn INR
OpEx Share:	2.5%	of CapEx
OpEx Escalation Y-o-Y:	5%	assumed
Total OpEx by 2038:	1,917	Mn INR
Discount rate for NPV:	10%	assumed

NPV of Total Costs:	8,924	Mn INR

Assumptions :

Renewable Energy							
Year	Particulars	Unit	Scope 1	Scope 2	% change Y-o-Y (Scope 1)	% change Y-o-Y (Scope 2)	Notes
Till 2025	% overall reduction from assets in Guj, TN, Others	%	0%	0%			
2026	% overall emission reduction from assets in Gujarat, Tamil Nadu, and Other	%	8%	78%			
Till 2026	% reduction in emission from assets in Maharashtra and AP	%	0%	0%			
2030	% overall emission reduction from assets in Maharashtra and AP using hybrid RE	%	45%	7%	11.17%	1.83%	
2035	% overall emission reduction from assets in Maharashtra and AP using offshore wind	%	45%	7%	4.96%	0.81%	
Till 2030	% reduction in emission from assets in Assam	%	0%	0%			
2033	% overall emission reduction from the assets in Assam	%	3%	7%	0.98%	2.41%	

Notes:
1. Till FY 24, it is assumed that no new initiatives will be deployed.
2. It is assumed that it takes 1 year for project implementation. So till FY 25, no emissions reduction is possible.
3. As Gujarat, Tamil Nadu, and Rajasthan states have favorable Solar and Wind hybrid policies, power generation equipment can be replaced with electrification using Renewable energy by 2025
4. Currently, setting up offshore wind power is not feasible. But as the government is looking for providing VGF for offshore wind projects and its goal of installing 30 GW of offshore wind by 2030, setting up offshore wind would be feasible then. The offshore wind plants will be set up gradually by 2035. The onshore hybrid capacity can be commissioned from 2026 onwards and gradually increase till max capacity till 2030. Also, ONGC has partnered with Equinor to set up a offshore wind plant to electrify offshore assets
5. The project implementation time for a small hydro plant in the northeast region is 5-8 years and hence, by 2033, the electrification of all the aseets in the north-east region would take place

Biodiesel

#	Biodiesel	FY 26	FY 27	FY 28	FY 29	FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38
1	Total Capacity (Mn kL)	0.40	0.42	0.43	0.45	0.17	0.18	0.18	0.19	0.19	0.12	0.12	0.13	0.04
2	Energy equivalent (TJ)	13.43	14.09	14.51	14.95	5.70	5.88	6.07	6.27	6.47	3.98	4.11	4.24	1.39

Biodiesel		
Net Substitution by 2038:	3.02	Mn kL
Project Start Year:	2030	
Service Duration until 2038:	9	years
Carbon Abatement by 2038:	**1.55**	Mn tCO_2e
Capacity 2G Ethanol plant:	100	KLD
CapEx (2G Ethanol plant):	5,232[35]	Mn INR
Capacity reqd. (2030):	467[36]	KLD
Capital Investment:	24,447[37]	Mn INR
OpEx Share:	2.0%	of CapEx
OpEx from Biodiesel Production by 2038:	4,400[38]	Mn INR

[35] BPCL gets green nod for Rs 747 cr ethanol project in Odisha - The Economic Times (indiatimes.com)

[36] IOCL spent 900 cr for 100 KLD plant and BPCL spent 747 core for 100 KLD plant

[37] In 2030 a reduction of 30% in CAPEX is assumed

[38] There will be net savings realized from Biodiesel substitution and revenue from selling excess biofuel. And from 2038 - it will be revenue for the organization

Discount rate for NPV:	10%	
NPV of Total Costs:	**26,313**	**Mn INR**

Assumptions

Biodiesel/BESS					
Year	**Particulars**	**Unit**	**Value**	**% change Y-o-Y**	**Source**
2025-2029	% emission reduction from Biodiesel	%	20%	4%	
till 2029	% reduction from EV till 2029	%	0%		
2030-2038	% overall reduction by switching to EV in Workcenters	%	43%	22%	
till 2029	% reduction from BESS till 2029	%	0%		
2030-2034	% overall reduction by swtiching to BESS in Services	%	20%		
2035-2037	% emission reduction from BESS	%	35%		
2038	% overall reduction by swtiching to BESS in Services	%	50%		
Notes:					
1. Till FY 24, it is assumed that no new initiatives will be deployed.					
2. It is assumed that it takes 1 year for project implementation. So till FY 25, no emissions reduction is possible.					
3. Biodiesel generator and BESS can replace existing diesel generator till 2035 in the Services.					
4. Remaining emissions from the company vehicles cannot be decreased and hence needs to be offset by 2038.					

Compressed Biogas

#	Compressed Biogas	FY 26	FY 27	FY 28	FY 29	FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38
1	NG consumption (MMScm)	407.37	427.46	440.25	453.71	467.83	482.60	498.04	514.14	530.89	548.31	566.39	585.12	604.52
	NG density (kg/Scm)	0.68												
	NG consumption (Mn MT)	0.60	0.63	0.65	0.67	0.69	0.71	0.73	0.76	0.78	0.81	0.83	0.86	0.89
2	NG substitution	20%	35%	50%	65%	80%	80%	80%	80%	80%	80%	80%	80%	80%
3	Total NG substituted (MMScm)	81.47	149.61	220.13	294.91	374.26	386.08	398.43	411.31	424.71	438.65	453.11	468.10	483.62
4	CBG Requirement (MMScm)	74.72	137.22	201.89	270.48	343.25	354.10	365.42	377.23	389.53	402.31	415.57	429.32	443.55
5	Density of CBG (kg/cu.m)	0.79	Compressed Biogas - Vyzag Bio Energy Fuel Pvt Ltd											
	CBG Requirement (Mn MT)	0.06	0.11	0.16	0.21	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35
6	Unit cost of CBG (INR/kg)	48.3	White_Paper_EOI_1.pdf (iocl.com)											

CBG		
Net CBG reqd. by 2038:	4,204.59	MMScm
Net CBG reqd. by 2038:	6.18	Mn MT
Project Start Year:	2026	FY
Service Duration until 2038:	13	years
Carbon Abatement by 2038:	**10.63**	Mn tCO_2e
Unit cost of CBG plant:	50[39]	Mn INR/TPD
Capacity reqd. CBG plant (2030):	0.27	Mn MT
Capacity reqd. CBG plant (2030):	904	TPD
Capital Investment:	45,195	Mn INR
Unit operational cost:	8	Mn INR/TPD
OpEx (2030 - 2038)	65,081	Mn INR
OpEx (2024 - 2029)	26,111	Mn INR
Total OpEx by 2038:	91,192	Mn INR
Discount rate for NPV:	10%	
NPV of Total Costs:	**71,610**	**Mn INR**

Assumptions

CBG					
Year	Particulars	Unit	Valu e	% change Y-o-Y	Source
Till 2025	% emission reduction	%	0%		
2026	% overall emission reduction from blending CBG (20%) in Power generation	%	12%		Hydrogen + Bioenergy excel sheet
2030	% overall emission reduction from blending CBG (80%)in Power generation	%	47%	9%	Hydrogen + Bioenergy excel sheet
Notes:					
1. Till FY 24, it is assumed that no new initiatives will be deployed. 2. It is assumed that it takes 1 year for project implementation. So till FY 25, no emissions reduction is possible. 3. As CBG is readily available in the market, CBG can be replaced with NG in the CHP unit in Hazira and Uran plants. From 2026, 20% of CBG can be blended with NG and continually increase to 80% till 2030 as CBG production capacity increases in India					

[39] Title With Picture Layout (cseindia.org)

Zero Routine Flaring

ZRF at each Asset	CapEx (Mn INR)	OpEx (Mn INR/yr)
CFB	0.3	0.0
MH	11,986.6	3.3
B&S	6,386.8	1.5
Jorhat	3,277.7	0.8
Rajahmundry	2,699.2	0.6
NH	2,421.7	0.5
Ankleshwar	2,068.3	0.4
Uran	1,770.4	0.3
Cauvery	1,761.8	0.3
Hazira	978.1	0.1
CPF	810.6	0.1
EOA	588.6	0.1
Mehsana	494.4	0.1
Ahmedabad	162.1	0.0
CTF	148.5	0.0
HPHT	99.3	0.0
Dahej	79.7	0.0
Tripura	30.5	0.0

Zero Routine Flaring		
Project Start Year:	2025	
Service Duration until 2038:	14	years
Carbon Abatement by 2038:	**20.46**	Mn tCO_2e
Capital Investment:	35,765	Mn INR
OpEx Share:		of CapEx
Total OpEx by 2038:	116	Mn INR
Total Revenue by 2038:		Mn INR
Discount rate for NPV:	10%	
NPV of Total Costs:	**35,795**	**Mn INR**

Assumptions

Zero Routine Flaring					
Year	Particulars	Unit	Value	% change Y-o-Y	Source
Till 2025	% emission reduction	%	0%		
2026	% emission reduction from offshore assets	%	65%		ZRF Excel Sheet
2028	% emission reduction from onshore +offshore assets	%	93%	14%	ZRF Excel Sheet
2030	% emission reduction by the year (all workcenters)	%	100%	4%	As per the initiative taken by ONGC
Notes:					
1. Till FY 24, it is assumed that no new initiatives will be deployed. 2. It is assumed that it takes 1 year for project implementation. So till FY 25, no emissions reduction is possible. 3. As offshore assets contribute to the highest flaring emissions of ONGC, several initiatives will be deployed in the offshore fields and hence no associated gas will be flared from the offshore assets from FY 26 4. From FY 27, new solutions will be deployed in the onshore assets and after 1 year of project implementation, no associated gas will be flared from onshore wells. 5. Till 2030, ONGC will achieve zero routine flaring from all of its workcenters					

Fugitive methane reduction

Fugitive Methane reduction		
Project Start Year:	2025	
Service Duration until 2038:	14	years
Carbon Abatement by 2038:	**4.75**	Mn tCO_2e
Methane quantity abated:	0.17	Mn tCH_4
Methane Heat Value:	52.5[40]	MJ/kg
Energy equivalent:	8,472	MMBtu
Avg. Net Cost of abatement:	-0.48	USD/MBtu
Total Net Cost of abatement:	-4.0	Mn USD
Discount rate for NPV:	10%	
NPV of Total Costs:	**-1.1**	**Mn USD**

[40] World Nuclear Association (world-nuclear.org)

Assumptions :

Methane Emissions					
Year	Particulars	Unit	Value	% change Y-o-Y	Source
Till 2025	% emission reduction	%	0%		
2026	% of methane emissions reduced at no net cost	%	53%		Methane emissions excel sheet
2031	% of methane emissions reduced at some net cost	%	73%	4%	Methane emissions excel sheet
2038/2050	% of methane emissions reduced	%	91%	3%	Net Zero by 2050 - A Roadmap for the Global Energy Sector (windows.net) (page 55)

Notes:

1. Till FY 24, it is assumed that no new initiatives will be deployed.
2. It is assumed that it takes 1 year for project implementation. So till FY 25, no emissions reduction is possible.
3. From 2026, the emissions reduction possible is taken from the methane emission excel sheets and the % reduction value is arrived considering the MAC curve
4. Till 2038, it is assumed that only 91% of the fugitive methane emissions can be reduced. The rest of the emissions cannot be reduced and need to be offset using carbon credits.

Green Hydrogen

Green Hydrogen	NG consumption (MMScm)	NG substitution	NG substituted (MMScm)	H2 Requirement (Mn MT)
FY 31	533	20%	107	0.09
FY 32	547	20%	109	0.10
FY 33	561	20%	112	0.11
FY 34	573	20%	115	0.12
FY 35	585	20%	117	0.13
FY 36	595	20%	119	0.14
FY 37	604	20%	121	0.14
FY 38	611	20%	122	0.15

Green Hydrogen		
Project Start Year:	**2031**	**FY**
Service Duration until 2038:	8	years
Total Hydrogen req. by 2038:	1.00	Mn tonnes
Carbon Abatement by 2038:	**7.61**	Mn tCO_2e
Production cost, Green H2:	300[41]	INR/kg
Total Production cost required:	36,957[42]	Mn INR
Energy reqd. per kg. H2:	39.4[43]	kWh/kg
Electrolyzer Efficiency:	80.0%[44]	
Hydrogen Purity:	99.8%	
Total Energy Required per kg.:	47.37	kWh/kg
Total Electrolyzer Capacity reqd.:	83	MWp
Discount rate for NPV:	10%	
NPV of Total Costs:	**36,957**	**Mn INR**

Assumptions :

Green Hydrogen					
Year	Particulars	Unit	Value	% change Y-o-Y	Source
Till 2030	% emission reduction	%	0%		
2031	% overall emission reduction from blending H2 (20%) in Power generation	%	12%		Hydrogen + Bioenergy excel sheet
2031	% overall emission reduction by switching fuel in GDU	%	1%		Hydrogen + Bioenergy excel sheet
2035	% overall emission reduction by switching fuel in Boiler/Furnace	%	14%	3%	
2031	% overall emission reduction by switching fuel in Heater Treater	%	26%		
Notes:					
1. As green hydrogen becomes viable in 2030, Hydrogen can entirely replace NG in some of the applications such as GDU, Heater Treater/Bath Treater.					
2. Remaining 20% hydrogen can be blended with CBG in the CHP units in Hazira and Uran Plant					

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[41] Green hydrogen fuel producers to get incentives worth Rs 30/kg; check details here - BusinessToday

[42] Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal (irena.org)

[43] Hydrogen Production: Fundamentals and Case Study Summaries; Preprint (nrel.gov)

[44] Technology Brief: Analysis of Current-Day Commercial Electrolyzers: National Renewable Energy Laboratory (Fact Sheet) (nrel.gov)

CCU :

CCU		
Project Start Year:	2031	FY
Service Duration until 2038:	8	years
Carbon Abatement by 2038:	**6.27**	Mn tCO_2e
Capital Investment:	120	USD/tCO_2
Total Investment:	62,449[45]	Mn INR
OpEx Share:	3.0%[46]	of CapEx
OpEx escalation Y-o-Y:	5.0%	assumed
Total OpEx by 2038:	17,890	Mn INR
Discount rate for NPV:	10%	assumed
NPV of Total Costs:	**70,795**	**Mn INR**

Assumptions

CCU					
Year	**Particulars**	**Unit**	**Value**	**% change Y-o-Y**	**Source**
Till 2030	% emissions reduction from acid gas venting	%	0%		
2031	% emission reduction from acid gas venting- Hazira and Uran	%	100%		CCUS Excel Sheet
Notes:					
1. Till FY 24, it is assumed that no new initiatives will be deployed.					
2. It is assumed that it takes 1 year for project implementation. So till FY 25, no emissions reduction is possible.					
3. A partnership between ONGC and the fertilizer industry can reduce acid gas venting emissions significantly by transporting CO2 via pipeline. It is assumed that urea manufacturers may need Hydrogen to manufacture NH3 which is an essential raw material in manufacturing urea. As green hydrogen will become viable by 2030, hence emission reduction in the ONGC's boundary will occur from 2030 onwards					
4. Subsequently, the methane in the acid gas needs to be converted to CO2 by retrofitting additional technologies such as flaring or chemical reaction of CH4 to CO2					

[45] What is shaping CCUS carbon capture costs? | Wood Mackenzie

[46] CCUS in clean energy transitions (windows.net)

BESS :

BESS	Total Capacity (MWh)
FY 30	5,140
FY 31	5,302
FY 32	5,472
FY 33	5,648
FY 34	5,832
FY 35	10,542
FY 36	10,889
FY 37	11,249
FY 38	16,603

BESS		
Project Start Year:	2030	FY
Service Duration until 2038:	9	years
Diesel Emission Factor:	2.68[47]	kg CO_2e/L
Diesel Qty. substituted:	25.5	Mn Litres
Diesel Density:	0.84 [48]	kg/L
Diesel Heat Value (NCV):	43	TJ/Gg or MJ/kg
DG Set Efficiency:	30%[49]	
Energy equivalent (Output):	77	Mn kWh
Carbon Abatement by 2038:	**0.07**	**Mn tCO_2e**
Levelized cost of storage (BESS):	6.60 [50]	INR/kWh
CapEx for BESS installation:	506	Mn INR
OpEx Share:	3.0%[51]	of CapEx
OpEx escalation Y-o-Y:	5.0%	assumed
Total OpEx by 2038:	167	Mn INR
Discount rate for NPV:	10%	assumed
NPV of Total Costs:	**577**	**Mn INR**

[47] WRI Emission Factors

[48] Bharat Petroleum

[49] ICF-2014-Diesel-Generators-Improving-Efficiency-and-Emission-Performance-in-India.pdf (shaktifoundation.in)

[50] https://pib.gov.in/PressReleaseIframePage.aspx?PRID=1985538

[51] Implementation of BESS in swedish electrical infrastructure. Gustav Arnberg. (diva-portal.org)

Assumptions

Biodiesel/BESS					
Year	**Particulars**	**Unit**	**Value**	**% change Y-o-Y**	**Source**
2025-2029	% emission reduction from Biodiesel	%	20%	4%	
till 2029	% reduction from EV till 2029	%	0%		
2030-2038	% overall reduction by switching to EV in Workcenters	%	43%	22%	
till 2029	% reduction from BESS till 2029	%	0%		
2030-2034	% overall reduction by swtiching to BESS in Services	%	20%		
2035-2037	% emission reduction from BESS	%	35%		
2038	% overall reduction by swtiching to BESS in Services	%	50%		
Notes:					
1. Till FY 24, it is assumed that no new initiatives will be deployed.					
2. It is assumed that it takes 1 year for project implementation. So till FY 25, no emissions reduction is possible.					
3. Biodiesel generator and BESS can replace existing diesel generator till 2035 in the Services.					
4. Remaining emissions from the company vehicles cannot be decreased and hence needs to be offset by 2038.					

18. List of Abbreviations

ACT	Accelerating CCUS Technology
AFOLU	Agriculture Forestry and Other Land Use
APLMA	Asia Pacific Loan Market Association
BEE	Bureau of Energy Efficiency
BESS	Battery Energy Storage System
BOGA	Beyond Oil and Gas Alliance
BRSR	Business Responsibility and Sustainability Reporting
CAPEX	Capital Expenditure
CBG	Compressed Biogas
CCUS	Carbon Capture, Utilization and Storage
CDM	Clean Development Mechanism
CER	Certified Emissions Reductions
COP 26	Conference of the Parties (United Nations Climate Change Conference, 2021)
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
DAC	Direct Air Capture
DBT	Department of Biotechnology
DG Set	Diesel Generator Set
DST	Department of Science and Technology
EOR	Enhanced Oil Recovery
ETS	Emissions Trading Schemes
FGRU	Flare Gas Recovery Unit
GAIL	Gas Authority India Limited
GBP	Green Bond Principles
GDP	Gross Domestic Product

GHGs	Greenhouse Gases (Carbon Dioxide, Methane, Nitrous Oxide, etc.)
GoI	Government of India
GLP	Green Loan Principles
GMI	Global Methane Initiative
GW	Giga Watt
HRSG	Heat Recovery Steam Generation
HSD	High Speed Diesel
ICMA	International Capital Market Association
ICP	Internal Carbon Pricing
IEA	International Energy Agency
IIGCC	Institutional Investors Group on Climate Change
IPCC	Intergovernmental Panel on Climate Change
LMA	Loan Market Association
MMSCM	Million Metric Standard Cubic Metres
MNRE	Ministry of New and Renewable Energy
MoPNG	Ministry of Petroleum and Natural Gas
Mtoe	Million tons of oil equivalent
NDC	Nationally Determined Contribution
NG	Natural Gas
Net-Zero	A target of completely negating the amount of greenhouse gases produced by human activity, to be achieved by reducing emissions and implementing methods of absorbing carbon dioxide from the atmosphere.
NHEM	National Hydrogen Energy Mission
NZE	Net-Zero Emissions
OGCI	Oil & Gas Climate Initiative
OPEX	Operational Expenditure
Pradhan Mantri JI-VAN yojana	Indian Government's policy support which aims to provide financial support to Integrated Bioethanol Projects using lignocellulosic biomass and other renewable feedstock

ppm	Parts per million
ppt	Parts per trillion
RE	Renewable Energy
SATAT scheme	Sustainable Alternative Towards Affordable Transportation (SATAT)
SBP	Social Bond Principles
SEBI	Securities and Exchange Board of India
SOP	Standard Operating Procedure
Science Based Targets (SBTi)	Targets that are in line with what the latest science deems necessary to prevent large-scale abrupt or irreversible environmental damage
Scope 1	Direct GHG Emissions: Emissions from sources that are owned or controlled by the company.
Scope 2	Indirect GHG Emissions: Emissions from the generation of purchased electricity/energy consumed by a company.
Scope 3	Other indirect GHG Emissions: Emissions occurring as a consequence of the activities of the company, but from sources not owned or controlled by the company.
SDG	Sustainable Development Goals
SDS	Sustainable Development Scenario
SLL	Sustainability Linked Loan
tCO_2e	tons of Carbon Dioxide equivalent
TCFD	Task Force on Climate-Related Financial Disclosures
TERI	The Energy and Resources Institute
UN	United Nations
CEWELL	Centre for excellence in Well Logging Technology
IPSHEM, Goa	Institute of Petroleum Safety, Heath and Environment Management
IEOT	Institute of Engineering and Ocean Technology
IOGPt	The Institute of Oil & Gas Production Technology
GHRTC	Gas Hydrate Research & Technology Centre
IRS	Institute Reservoir Studies
RTI	Right to Information

GEOPIC	Geodata Processing and Interpretation Centre
IDT	Institute of Drilling technology
KDMIPE	Keshav Deva Malaviya Institute of Petroleum Exploration

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