# APPENDICES:
MEDIUM TERM

CARIBBEAN ENERGY CHAMBER

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# APPENDIX: MEDIUM TERM

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## Pathways to Developing Eastern Caribbean Countries

**MEDIUM TERM: POTENTIAL GEOTHERMAL SCENARIOS**

**OPTION 1:**
**"RESILIENCE"**

**APPROX USD 3 BILLION PROJECT**

**OPTION 2:**
**"BIG BUT NOT AUDACIOUS"**

**APPROX USD 10-15 BILLION PROJECT**

**OPTION 3:**
**"BLUE SKY"**

**APPROX USD 40 BILLION PROJECT**

# APPENDIX: MEDIUM TERM

## Pathways to Developing Eastern Caribbean Countries

### MEDIUM TERM: GEOTHERMAL POTENTIAL PATHWAYS

#### OPTION 1: "RESILIENCE"

**Gives Eastern Caribbean energy security,** affordability and low carbon transition needs with export via a HVDC sub-sea cable to Antigua and Montserrat from Nevis

**In country, surplus electricity can be sold to cruise ships during berthing or used for desalination**

#### OPTION 2: "BIG BUT NOT AUDACIOUS"

Gives Eastern Caribbean and Barbados energy security, affordability and low carbon transition needs with a **limited surplus for export** to other islands (eg T&T)

In country, surplus electricity can be sold to cruise ships during berthing or used for desalination

Electrical power supply resilience will be enhanced with an inter-island interconnecting sub-sea HVDC grid

#### OPTION 3: "BLUE SKY"

Dream big. Gives Eastern Caribbean and Barbados energy security, affordability and low carbon transition needs and **export surplus energy to produce green hydrogen** and green ammonia in Trinidad and Tobago

In country, surplus electricity can be sold to cruise ships during berthing or used for desalination

Electrical power supply resilience will be enhanced with an inter-island interconnecting sub- sea HVDC grid

# APPENDIX: MEDIUM TERM

## Pathways to Developing Eastern Caribbean Countries Geothermal Energy Potential

### MEDIUM TERM: GEOTHERMAL POTENTIAL PATHWAYS

### OPTION 1: "RESILIENCE"

**Gives Eastern Caribbean energy security, affordability and low carbon transition needs with export via a HVDC sub-sea cable to Antigua and Montserrat from Nevis.**

| Required Investments | USD |
|---|---|
| HVDC Sub – 200 Km Sea Cable @ 2-7 M USD/km[1] | 0.4–1.4 Billion |
| Geothermal Power Plants @ 5,750 USD/kW (Assumes 380 MW) | 2.2 Billion |
| **Total Cost** | **~2.6–3.6 Billion** |

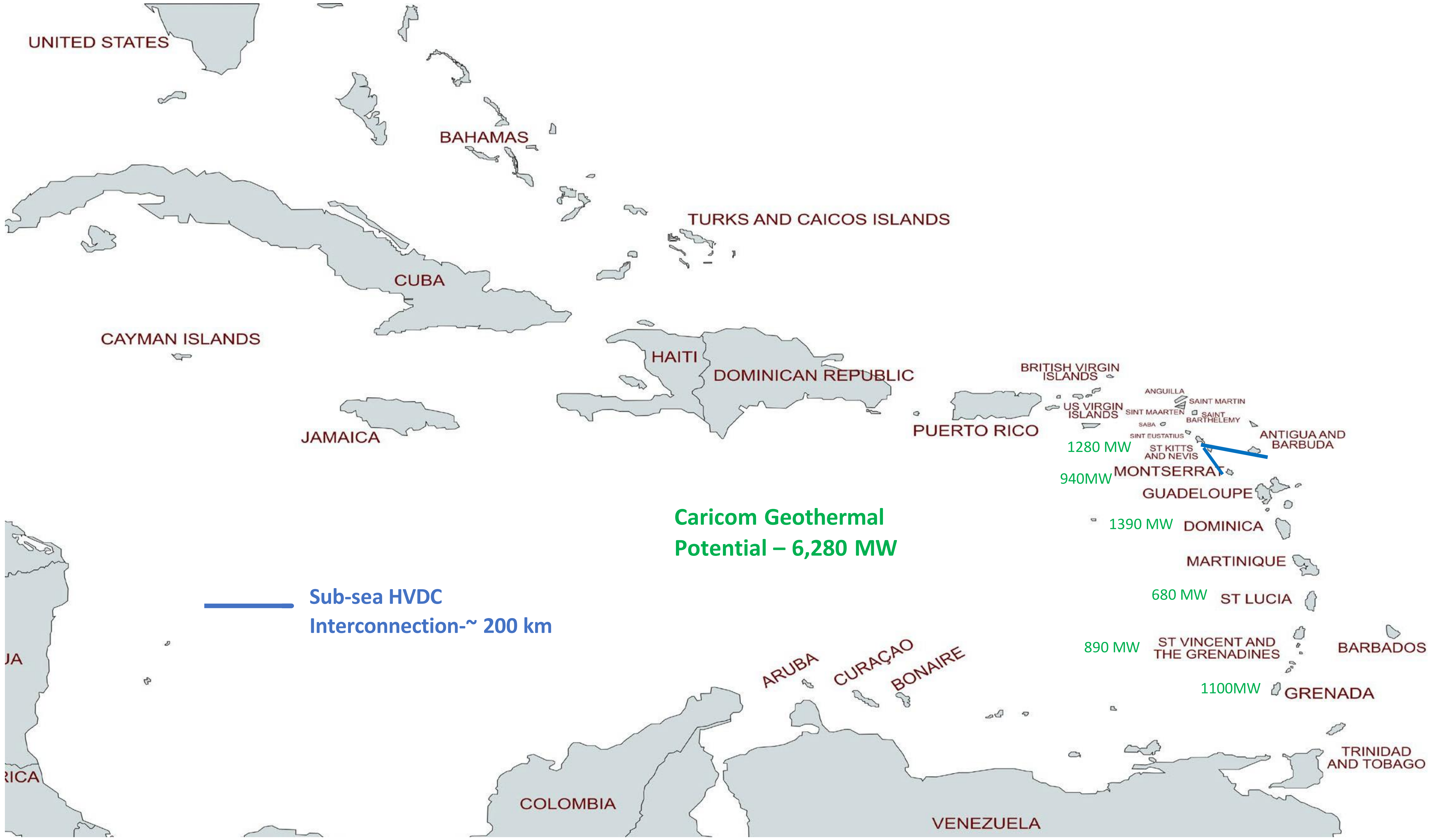
### COMMERCIAL & TECHNICAL FEASIBILITY

**TECHNICAL:**

**The feasibility of laying the interconnecting HVDC submarine cable would have to be assessed.**

**COMMERCIAL:**

**At an installed cost of 4,500 USD/kW for geothermal, the LCOE is 11 US¢/kWh.**



# APPENDIX: MEDIUM TERM

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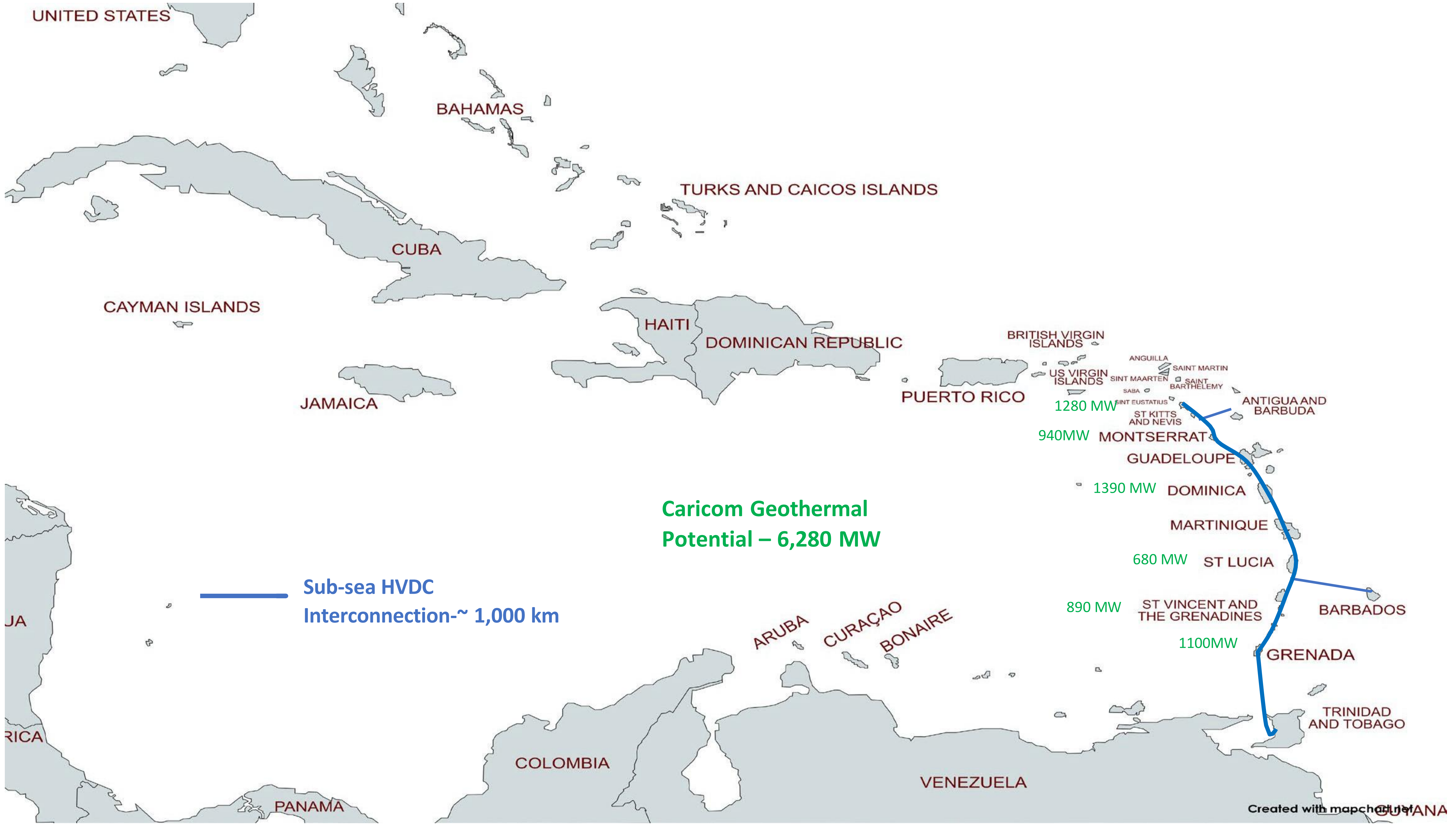
## Pathways to Developing Eastern Caribbean Countries Geothermal Energy Potential

### MEDIUM TERM: GEOTHERMAL POTENTIAL PATHWAYS




### OPTION 2: "BIG BUT NOT AUDACIOUS"

**Gives Eastern Caribbean and Barbados energy security, affordability and low carbon transition needs and harness surplus energy to produce "some" green hydrogen and green ammonia in Trinidad and Tobago. Electrical power supply resilience enhanced with an inter-island interconnecting sub-sea HVDC grid**

| Required Investments | USD |
|---|---|
| HVDC Sub –1300 Km Sea Cable @ 2-7 M USD/km[1] | 2.6-9.1 Billion |
| Geothermal Power Plants @ 4,500 USD/ KW[2] Assumes 1,000 MW dedicated for all EC islands and Barbados (25% above installed capacity) and 500 MW to T&T | 6.8 Billion |
| **Total Cost** | **~9.4-15.9 Billion** |

### COMMERCIAL & TECHNICAL FEASIBILITY

**TECHNICAL:**

**The feasibility of laying the interconnecting HVDC submarine cable would have to be assessed.**
**T&T ammonia plants can only take 20% green H2**

**COMMERCIAL:**

**At an installed cost of 4,500 USD/kW for geothermal, the LCOE is 11 US¢/kWh**

# APPENDIX: MEDIUM TERM

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## Pathways to Developing Eastern Caribbean Countries Geothermal Energy Potential

### MEDIUM TERM: GEOTHERMAL POTENTIAL PATHWAYS

### OPTION 3: "BLUE SKY"

**Gives Eastern Caribbean and Barbados energy security, affordability and low carbon transition needs and harness surplus energy to produce green hydrogen and green ammonia in Trinidad and Tobago. Electrical power supply resilience enhanced with an inter-island interconnecting sub-sea HVDC grid. Surplus power can be sold in country to berthing cruise ships.**

| Required Investments | USD |
|---|---|
| HVDC Sub – 1300 Km Sea Cable @ 2-7 M USD/km[1] | 2.6-8.1 Billion |
| Geothermal Power Plants@ 4,500 USD/KW[2]. Assume 1,000 MW dedicated for all islands and Barbados (25% above installed capacity) and 5,000 MW to T&T. | 22.5 Billion |
| Electrolyzers to produce hydrogen in T&T. Assume USD 2000 per KW installed.[3] | 10.0 Billion |
| Upgrade Ammonia Plants for green hydrogen feed- Guesstimate USD 150M each for 11 plants | 1.7 Billion |
| **Total Cost in USD** | **~36.8 – 42.3 Billion** |

### COMMERCIAL & TECHNICAL FEASIBILITY

**TECHNICAL:**

**The feasibility of laying the interconnecting HVDC submarine cable would have to be assessed. TT ammonia plants can only take 20% green hydrogen**

**COMMERCIAL:**

**At an installed cost of 4,500 USD/KW for Geothermal the LOCE is 11 USc/KWh. At that cost of electricity, the cost of producing hydrogen is 15.1 USD/Kg versus 1.5 USD/kg using natural gas at a price is at ~ 5 USD/MMBTU. At a hydrogen price of 15.1 USD/kg it would be commercially infeasible to produce green ammonia when the hydrogen price in other green export locations could be < 4 USD/kg.**

# APPENDIX: MEDIUM TERM

## Electricity Data for Caribbean Islands (2018–2021)

### MEDIUM TERM: GEOTHERMAL CONCLUSIONS

- Producing hydrogen and green ammonia from geothermal electrical power in the next 5 years at a price of hydrogen of 15 USD/kg is commercially infeasible. This may change in the future if both geothermal and electrolyzer costs were to significantly decrease and realize a hydrogen cost that is cost competitive < 4 USD/kg
- Option 1 seems to be the most realistic option given the magnitude of capital required around USD 3 Billion. It reduces current electrical tariffs for the Eastern Caribbean countries which average >0.30 USD/KWh to around 0.11 USD/KWh
- Advancing Option 1 with focus does not preclude Options 2 and 3.
- Option 2 certainly can be assessed, however, given the magnitude of capital required of USD 10-15 Billion it likely would be in the medium- term horizon of 5-10 years.
- Option 3 at estimated cost of approx USD 40 Billion is a long-term horizon >10 years activity which could only be commercial feasible with a very significant cost reduction in geothermal and electrolyzer costs
- **Steps should be taken in the short term to focus and accelerate development activity on Option 1**

# APPENDIX: MEDIUM TERM

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## References


1. **SUB-SEA HVDC CABLE COSTS**

   https://www.transpower.co.nz/news/transpower-secures-cables-ship-and-installation-cook-strait-project

   https://www.escaeu.org/articles/submarine-power-cables/

   https://en.wikipedia.org/wiki/NorNed

   https://en.wikipedia.org/wiki/East%E2%80%93West_Interconnector

   https://www.irishtimes.com/news/east-west-interconnector-is-opened-1.737858#:~:text=The%20interconnector%20actually%20cost%20%E2%82%AC,testing%20phase%20on%20August%207th.

   https://www.escaeu.org/articles/submarine-power-cables/

   https://besacenter.org/the-great-sea-interconnector-prospects-for-an-electrical-cable-connecting-greece-cyprus-and-israel/

   https://www.enerdata.net/publications/daily-energy-news/cyprus-and-greece-sign-mou-eu19bn-great-sea-interconnector-project.html#:~:text=Greece%20and%20Cyprus%20have%20signed,the%20future%20of%20the%20project.

   https://en.wikipedia.org/wiki/Great_Sea_Interconnector#:~:text=Cyprus%20will%20be%20connected%20with,will%20have%201000%20MW%20capacity.

   https://en.wikipedia.org/wiki/Australia-Asia_Power_Link

2. **GEOTHERMAL POWER PLANT COSTS**

   https://www.caribank.org/newsroom/news-and-events/cdb-approves-usd-348-million-loan-build-geothermal-energy-plant-dominica#:~:text=CDB's%20funding%20%E2%80%93%20with%20resources%20from,as%20equity%20from%20the%20GPC https://www.thinkgeoenergy.com/irena-reports-22-lower-lcoe-of-geothermal-projects-in-2022/

   Renewable Power Generation Costs In 2023- Irena

3. **ELECTRICITY SECTOR OVERVIEW**

   OECS Member States-Support for a Renewable Energy Transition in OECS Countries- GGGI Sept 2022.

4. **BARBADOS ENERGY TRANSITION AND INVESTMENT PLAN 2022**

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## Assumptions

1. **SUBMARINE HVDC CABLES**
   - Change out of HVDC cable between New Zealand South and North Islands – budget USD 450M, distance is 40 km and depth is 250m. Planned to be completed in 2031– 11.25M USD/Km.
   - Great Sea Interconnector cable (GSI), formerly known as the EuroAsia Interconnector- Crete and Cyprus – budget € 1.9 billion, distance 898km and depth up to 3000m. Expected to be commissioned in May 2025 – 2.4 M USD /km
   - East West Connector between Wales and Ireland – installed cost €600 million , distance 186 km. Commissioned in 2012 –4.2 M USD/km
   - NorNed is a 580-kilometre (360 mi) long high-voltage direct current submarine power cable between

2. **GEOTHERMAL TOTAL INSTALLED COSTS**
   - Dominica – USD 68M for 10MW or 6,800 USD /KW. This was a first of a kind and there is the opportunity for cost reduction in subsequent projects.
   - Global average in 2022 according to IRENA is 4,579 USD/KW.
   - It is assumed that the installations in the Eastern Caribbean can be done for 4,500 USD/KW for Option 1 and 2; and 5,750 USD/KW for Option 3

3. **ELECTROLYZER COST-DOE**
   - Clean Hydrogen Production Cost Scenarios with PEM Electrolyzer Technology – May 2024- 2,000 USD/KW installed.

# APPENDIX: MEDIUM TERM

## ECS + Barbados Installed Electricity Generating Capacity and Peak Demand

| COUNTRY | INSTALLED CAPACITY (MW) | PEAK DEMAND (MW) | ELECTRICITY TARIFFS (USD/K |
|---|---|---|---|
| Anguilla | 26.0 | 13.7 | 0.35 |
| Antigua and Barbuda | 85.3 | 50.0 | |
| Dominica | 26.0 | 16.4 | 0.35–0.39 |
| Grenada | 55.8 | 31.9 | 0.28 |
| Montserrat | 2.5 | 2.3 | |
| Nevis | 20.6 | 9.5 | |
| St. Kitts | 46.9 | 26.0 | |
| St. Lucia | 91.4 | 60.9 | 0.28–0.31 |
| St. Vincent | 53.8 | | 0.33 |
| Barbados[5] | 360.0 | | |
| **TOTAL** | **768.2** | | |

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## T&T Energy Wind and Green Hydrogen Economics

**MEDIUM TERM: T&T WIND POTENTIAL SCENARIOS**

**OPTION 1:**
**"RESILIENCE"**

**APPROX**
**USD450 MILLION**
**PROJECT**

**OPTION 2:**
**"BIG BUT NOT**
**AUDACIOUS"**

**APPROX**
**USD 1 BILLION**
**FOR <u>SOME</u>**
**GREEN H2**

**OPTION 3:**
**"BLUE SKY"**

**> USD 18 BILLION FOR**
**GREEN H2 FOR <u>FOUR</u>**
**1,800 MT PER DAY NH3**
**PLANTS**

# APPENDIX: MEDIUM TERM

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**Pathways to Developing Eastern Caribbean Countries**

**MEDIUM TERM: T&T WIND POTENTIAL SCENARIOS**

## OPTION 1: "RESILIENCE"

On-shore Wind is possible for 3 USc/KWhr to use in communities in short term (with cost approx USD 450 million for 300 MW)

## OPTION 2: "BIG BUT NOT AUDACIOUS"

On-shore Wind for some Green Hydrogen Production (with approx cost >USD 1 billion)

- 300 MW project with 75 4MW turbines needs land of 100 sq km
- Only supplies approx 10% green hydrogen for an ammonia plant
- Produces expensive hydrogen at approx 4 USD/Kg
- Equiv natural gas cost 6.5 USD/MMBTU and carbon taxes at 100 USD/MT
- Critical issue is availability of land (that also has wind)

## OPTION 3: "BLUE SKY"

Off-shore Wind is more expensive than on-shore but helps with land scarcity issue

# APPENDIX: MEDIUM TERM

## Assumptions for T&T On-shore Wind Generation and Hydrogen Produced via PEM Electrolysis for 2030

| ITEM | BASE | LOW | HIGH |
|---|---|---|---|
| 1. Wind Generation US Installed Capital Costs[1] (2022 USD/KW) | 1500 | 1200 | 2000 |
| 2. Reduction in TIC due to innovations every 5 years (% of TIC reduction) | 12% | 25% | 0% |
| 3. Adjustment factor for installing in T&T versus US | 1.25 | 1.1 | 1.5 |
| 4. Wind Generation Total Operating Costs[2] (USD/KW/yr) | 44 | 33 | 59 |
| 5. Operation escalation costs % per year from start up year | 2% | 2% | 2% |
| 6. Wind Capacity Factor[3] (%) | 35% | 50% | 20% |
| 7. Discount Rate (%) | 15% | 10% | 20% |
| 8. Economic Life (Yrs) | 20 | 30 | 20 |
| 9. Investment Incentives - Wear and tear allowances on equipment (%) | 150% | 150% | 150% |
| 10. Loan Debt % | 60% | 70% | 50% |
| 11. Tax Rate | 35% | 35% | 35% |
| 12. Debt interest rate | 5% | 5% | 5% |
| 13. Loan Tenor (Yrs) | 10 | 10 | 10 |

**References**


1 US Deparment of Energy- Landbased Wind Report 2023 Edition
2 US Deparment of Energy- Landbased Wind Report 2023 Edition
3 US Deparment of Energy- Landbased Wind Report 2023

# APPENDIX: MEDIUM TERM

CARIBBEAN ENERGY CHAMBER

## Assumptions for T&T On-shore Wind Generation and Hydrogen Produced via PEM Electrolysis for 2030

| ITEM | BASE | LOW | HIGH |
|---|---|---|---|
| 1. Electrolyzer US Total Installed Capital Costs[4] (2023/2024 USD/KW) | 2000 | 1500 | 2500 |
| 2. Equipment cost as a % of Total Installed Capital Cost[4] (%) | 45% | 45% | 45% |
| 3. Installation cost as a % of Total Installed Capital Cost[4] (%) | 55% | 55% | 55% |
| 4. Reduction in TIC due to innovations every 5 years (% of TIC reduction) | 12% | 25% | 0% |
| 5. Adjustment factor for installation costs in T&T versus US | 1.25 | 1.1 | 1.5 |
| 6. Onstream Factor for electrolyzer = Capacity Factor for wind generation | 35% | 50% | 20% |
| 7. Electrolyzer Operating Costs | | | |
| a. Energy Consumption (kWh/kg of H2) | 57.5 | 52 | 60 |
| b. Normal O+M costs[4] (% of Cost of Equipment) | 5% | 4% | 6% |
| c. Major maintenance, stack replacement (% of TIC every 40,000 hours)[4] | 11% | 11% | 15% |
| 8. Discount Rate (%) | 15% | 10% | 20% |
| 9. Economic Life (Yrs) | 20 | 30 | 20 |
| 10. Investment Incentives - Wear and tear allowances on equipment (%) | 150% | 150% | 150% |
| 11. Tax Rate | 35% | 35% | 35% |
| 12. Loan Debt % | 60% | 70% | 50% |
| 13. Loan Interest Rate % | 5% | 5% | 5% |
| 14. Loan Tenor (Yrs) | 10 | 10 | 10 |

**References**

4 US Department of Energy – Department of Hydrogen. 2024 Report – Production Cost Scenarios with Electrolyzer PEM Technology

# APPENDIX: MEDIUM TERM

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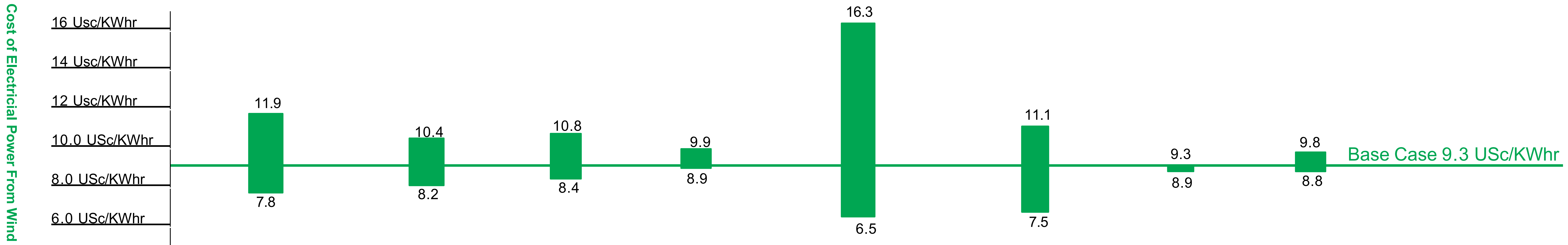
## T&T On-shore Wind Generation Economics Tornado Diagram For A 300 MW Generating Capacity Case For a Start Up in 2030




| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Low Case | 1200 | 25% | 1.1 | 33 | 50% | 10% | 30 | 70% |
| High Case | 2000 | 0% | 1.5 | 59 | 20% | 20% | 20 | 50% |
| Base Case | 1500 | 12% | 1.25 | 44 | 35% | 15% | 20 | 60% |
| Variable | Wind Generation US Installed Capital Costs[1] (2022 USD/KW) (Assumes a generating capacity of >200 MW) | Reduction in TIC due to innovations every 5 years (% of TIC reduction) | Adjustment factor for installing in T&T versus US (Impacted by shipping costs and construction and project delivery productivity in a T&T environment.) | Wind Generation Total Operating Costs[2] (USD/KW/yr) | Wind Capacity Factor[3] (%) (At this time as a placeholder the range is assumed to be similar to the US. This will be more accurately assessed when the current T&T WRAP LiDAR studies are completed at Galeota and Waterloo in Q4 2025/Q1 2026.) | Discount Rate (%) | Economic Life (Yrs) | Debt Financing % |

**Assuming Vesta's 4 MW on-shore wind turbines with blade diameters of 160 m, the area for 75 turbines (300 MW) would be approximately <u>100 sq km</u>**

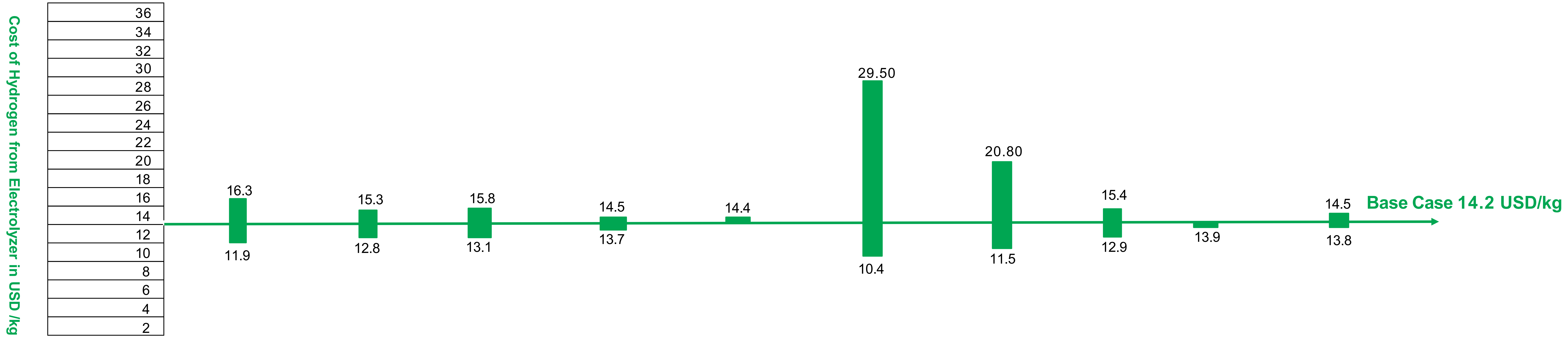

| | Cost of Electricity (USD/KWhr) |
|---|---|
| Low Case when all the variables are low | 0.028 |
| | |
| Base Case when all the variables are base | 0.093 |
| | |
| High Case when all the variables are hi gh | 0.36 |

**Regional On-land Wind Capacity Factor References**

1. Jamaica – 38%-42% over the 8 years it has been operating history. Source BMR
2. Aruba- 55%-Source BMR
3. Puerto Rico – As low as 27%- Source BMR

# APPENDIX: MEDIUM TERM

## T&T 300 MW PEM Hydrogen Generator Economics Using Electrical Power From Wind For a Start Up in 2030




| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Low Case | 1500 | 25% | 1.1 | 4% | 11% | 0.028 | 50% | 10% | 30 | 70% |
| High Case | 2500 | 0% | 1.5 | 6% | 15% | 0.360 | 20% | 20% | 20 | 50% |
| Base Case | 2000 | 12% | 1.25 | 5% | 11% | 0.093 | 35% | 15% | 20 | 60% |
| Variable | Electrolyzer US Installed Costs[4] (2022 USD/KW) (Assumes a generating capacity of >200 MW) | Reduction in TIC due to innovations every 5 years (% of TIC reduction) | Adjustment factor for installing in T&T versus US (Impacted by shipping costs and construction and project delivery productivity in a T&T environment.) | Electrolysis Operating Costs[4]( USD/KW/yr) | Electrolysis Major Maintenance cost every 5 years to replace stack (USD installed KW/yr) | Electricity Cost from Wind Generation (USD /KWhr) | Onstream Factor for electrolyzer to match wind capacity factor[3] (%) (At this time as a placeholder the range is assumed to be similar to the US. This will be more accurately assessed when the current T&T WRAP LiDAR studies are completed at Galeota and Waterloo in Q4 2025/Q1 2026.) | Discount Rate (%) | Economic Life (Yrs) | Debt Financing % |

| | Cost of Hydrogen (USD/Kg) |
|---|---|
| Low Case when all the variables are low | 4.2 |
| | |
| Base Case when all the variables are base | 14.2 |
| | |
| High Case when all the variables are high | 35.7 |

# APPENDIX: MEDIUM TERM

## Possible T&T Market for Green Hydrogen

### DE-CARBONIZING AMMONIA PRODUCTION

- T&T currently produces about 12,618 MT per day of anhydrous ammonia which consumes 437 MMscfd of natural gas.[1]
- 0.177 MT of hydrogen is required to produce 1 MT of ammonia.[2]
- T&T current hydrogen demand for its ammonia plants is 12618 X 0.177= 2,145 MT/day.
- Without a significant revamp of the **current ammonia plants they can receive up to 20% of a blend of hydrogen with natural gas**. This will reduce the amount of CO2 emitted. However, **to make ammonia with only green hydrogen will require a new build ammonia plant**
- A 20% blend of hydrogen for all of T&T's ammonia plants will require 0.20X 2,145 or 429 MT of hydrogen/day.
- 300 MW Electrolyzer powered by wind turbine electricity will produce on average 43 MT of H2 per day or 10% of the T&T ammonia plant requirements.
- An SMR ammonia plant produces roughly 2.4 MT of CO2 for every MT of ammonia produced[3]

### REFERENCES


1. T&T MEEI Production Bulletins for Jan -Sept 2024 ammonia production
2. Derived from the equation N2 +3H2 = 2NH3. Molecular weight of Nitrogen 14 and Hydrogen 1
3. Life cycle energy use and greenhouse gas emissions of ammonia production from renewable resources and industrial by-products- Xinyu Liu, * Amgad Elgowainy and Michael Wang

# APPENDIX: MEDIUM TERM

## Possible T&T Market for Green Hydrogen

| | USD/MMBTU | COST OF HYDROGEN (USD/KG) |
|---|---|---|
| Cost of natural gas | 3.5 | 1.28 |
| | 4 | 1.46 |
| | 5 | 1.83 |
| | 6 | 2.19 |

# APPENDIX: MEDIUM TERM

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## T&T Wind Key Takeaways

### ON-SHORE WIND GENERATION

It is possible to get to a cost of < 3 USc/KWhr if the following key variables fall within the following ranges:

- Wind capacity factor > 50%
- Installed capital cost in T&T < 1200 USD/KW
- Low-cost debt financing < 5%
- Equity investors are willing to accept =< 10% return on investment
- For a 300 MW project with 75 4MW turbines an area of close to 100 sq km will be required. Land availability for a large-scale wind project is critical. However, this would only supply approx 10% green hydrogen for a plant
- Off-shore wind generation is more expensive that on-shore wind so the same would apply to a greater extent. The additional benefit of off-shore wind is that it would not be competing for on- shore land space

### ON-SHORE WIND GENERATION FOR GREEN HYDROGEN PRODUCTION

It is possible to get to a cost of ~ 4.2 USD/kg IFF the following key variables fall within the following ranges:

- Onstream factor > 50%
- Electricity cost < 3 USc/KWhr
- Low-cost debt financing < 5%
- Equity investors are willing to accept a =< 10% return on investment
- Installed capital cost is < 1500 USD/KW
- However, even at close to 4 USD/Kg for hydrogen, natural gas cost would have to be close to 6.5 USD/MMBTU and carbon taxes at 100 USD/MT for it to be cost neutral for ammonia plants to purchase "green" hydrogen at that cost

# APPENDIX: MEDIUM TERM

## T&T WIND SUMMARY

**OPTION 1:**
**"RESILIENCE"**

**APPROX USD 450 MILLION PROJECT AND COULD BE USED FOR COMMUNITY POWER**

**OPTION 2:**
**"BIG BUT NOT AUDACIOUS"**

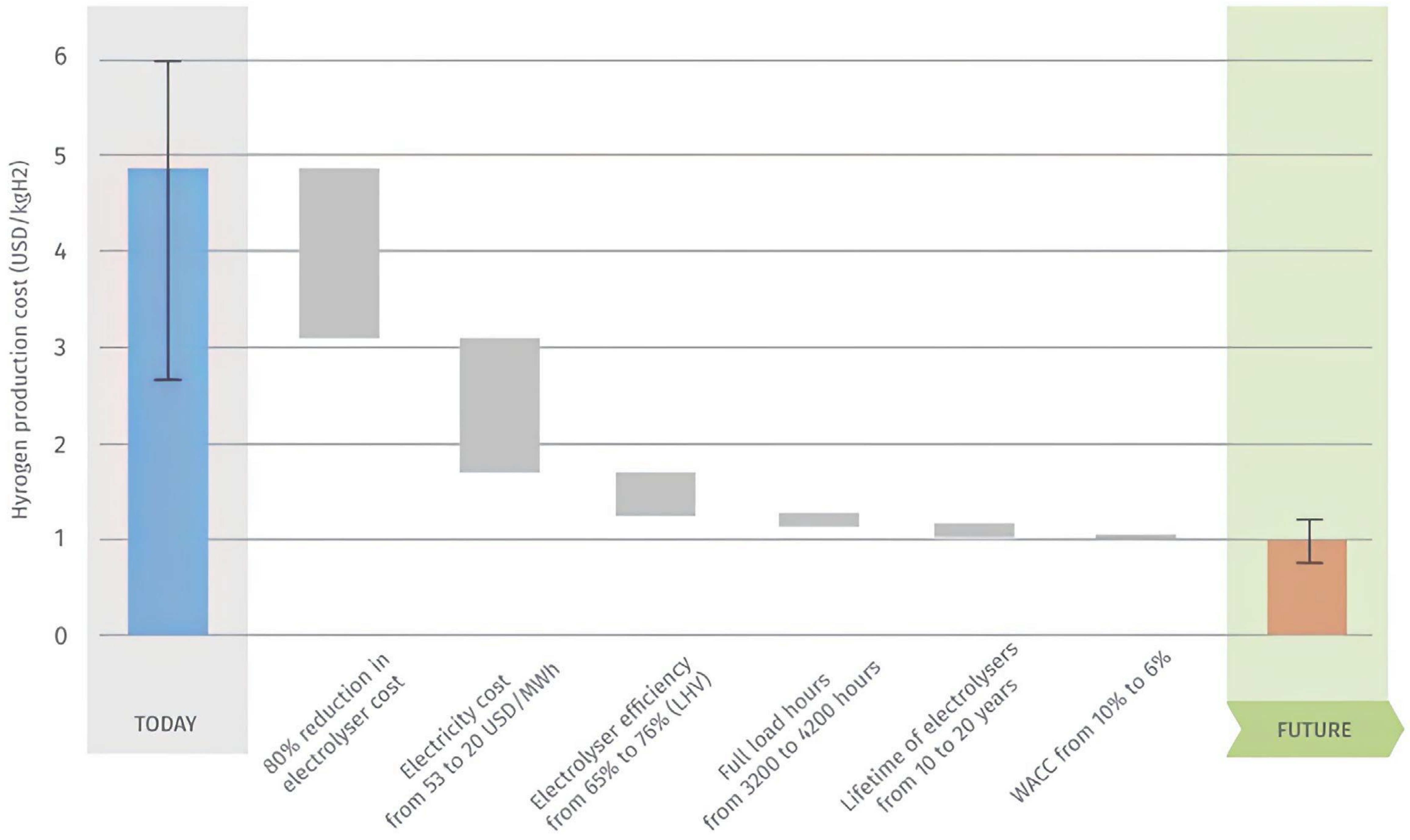
**> USD 1 BILLION WOULD NOT BE COST COMPETITIVE FOR SOME GREEN H2 CURRENTLY**

**OPTION 3:**
**"BLUE SKY"**

**FOR SOME GREEN H2 WOULD NOT BE COST COMPETITIVE**

# APPENDIX: MEDIUM TERM

## Hydrogen cost forecasts




**SOURCE: IRENA, 2020a**

Note: "Today" captures best and average conditions. "Average" signifies an investment of USD 770/kilowatt (kW), efficiency of 65% (lower heating value -LHV), an electricity price of USD 53/ MWh, full load hours of 3200 (onshore wind), and a weighted average cost of capital (WACC) of 10% (relatively high risk). "Best" signifies investment of USD 130/kW, efficiency of 76% (LHV), electricity price of USD 20/MWh, full load hours of 4200 (onshore wind), and a WACC of 6% (similar to renewable electricity today).

**Based on IRENA analysis**

# APPENDIX: MEDIUM TERM

## Blue vs Green Ammonia

- Most of the nearly 180 Mt of ammonia produced globally every year are generated via reforming of natural gas (72%) or coal (26%), resulting in approximately 500 Mt of carbon dioxide(CO2) emissions. The ammonia industry alone accounts for almost 2% of globalCO2 emissions, 90% of which are associated with the production of the hydrogen (H2) required for the ammonia synthesis[1]

- Production tax credits (PTC) for clean hydrogen production via the 45V and carbon sequestration via the 45Q under the Inflation Reduction Act (IRA) in the United States have sparked interest in large-scale commercial low-carbon ammonia projects[1]

- With the production tax credits, blue ammonia is likely to be the most economical production route in the near-term, being cheaper than conventional ammonia which is not eligible for any credits. The economics of electrolytic ammonia depend heavily on the price of reliable low-carbon electricity. A levelized cost of electricity of about 35 $/MWh and lower is required for electrolytic ammonia to be competitive with blue ammonia at average gas prices and upstream emissions[1]

- Overall, the IRA tax credits improve the economics of low-carbon ammonia production significantly and result in it being competitive with conventional ammonia production, enabling significant carbon emission reduction[1]

**REFERENCES**

1. A comparative techno-economic assessment of blue, green, and hybrid ammonia production in the United States- Sustainable Energy Fuesl Royal Society Chemistry 2024

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## Financing H2 Project

- Supply side – reducing cost a key priority
- Demand side - There has been modest progress in creating demand for green hydrogen. It is important that both governments and companies send stronger collective demand signals by moving from targets to policies and from commitments to contracts. Identifying pre-defined offtakers is crucial. Large green hydrogen projects in emerging markets and developing countries typically face high financing costs due to actual and perceived risks, deterring investors from entering this emerging sector. The top risk category mentioned by project developers is offtake risks, followed by political, regulatory and infrastructure risks (World Bank, 2023). Strong demand signals are required to secure investments into green hydrogen production projects (EC, 2023e)
- De-risking and risk sharing will play a crucial role in catalysing green hydrogen production in emerging markets and developing countries. Political support, multilateral development banks and other finance institutions are required to design and implement more suitable instruments to enable low-cost finance access and create an enabling environment for green hydrogen production (GH2, 2022; IRENA, 2023b; World Bank, 2023)

International Co-operation To Accelerate Green Hydrogen Deployment- Irena 2024

# APPENDIX: MEDIUM TERM

CARIBBEAN ENERGY CHAMBER

## Distribution and Storage of Hydrogen

- Hydrogen in the U.S. is produced at, or near, where it will be used, reflecting difficulties with transportation
- Hydrogen can be transported to point of use via pipeline, or over the road using liquid tanker, or tube trailer trucks
- Pipelines have the lowest cost to deliver hydrogen at \$0.2-0.5/kg$H_2$. There are ~1,600 mi in the U.S.6,15 Tube trailers transport compressed hydrogen, typically 200 miles or less, but are expensive at \$0.9-1.9/kg$H_2$
- Liquid tankers are better suited than tube trailers for transporting larger amounts of hydrogen over longer distances but are more expensive at \$2.7-3.2/kg$H_2$ due to energy and equipment requirements for the liquefaction process
- Storage of hydrogen as a compressed gas typically requires high-pressure tanks at 350-700 bar (atmospheric pressure is 1.013 bar)
- Liquid storage can achieve greater densities than compressed gas, but is more energy intensive and requires extremely low temperatures since its boiling point is −253°C (-423°F)
- Underground hydrogen storage may be possible. Conventional options include salt caverns, while proposed sites include abandoned coal mines and refrigerated mined caverns

Center for Sustainable Systems – University of Michigan

# APPENDIX: MEDIUM TERM

**CO2 Reduction Impact of Utilizing Venezuelan Flare/Vented Natural Gas for Ammonia/Methanol/LNG**

- SIGNIFICANTLY REDUCES CO2 EQUIVALENT EMISSIONS IN COMPLETE COMBUSTION PROCESS
- REASONABLE INVESTMENT SIZE
- CAN BE IMPLEMENTED IN MEDIUM TERM (NO DOWNSTREAM IMPLEMENTATION BARRIERS LIKE GREEN HYDROGEN)
- PROVIDES EXPORTS TO EU, ASIA AND OTHER COUNTRIES
- POTENTIAL SOURCE OF “KHAKI” / GREEN AMMONIA IF GREEN CREDITS CAN BE STRUCTURED

# APPENDIX: MEDIUM TERM

CARIBBEAN ENERGY CHAMBER

## Analysis

Each greenhouse gas (GHG) has a different global warming potential (GWP) and persists for a different length of time in the atmosphere. The three main greenhouse gases and their 20-year global warming potential (GWP) compared to carbon dioxide are:

- 1 x – carbon dioxide ($CO_2$) NOTE: Any carbon dioxide added to the atmosphere will hang around for a long time: between 300 to 1,000 years. All this time, it will be contributing to trapping heat and warming the atmosphere.
- 84 x – methane ($CH_4$) – I.e. Releasing 1 kg of $CH_4$ into the atmosphere is about equivalent to releasing 84 kg of $CO_2$. Methane's 100-year GWP is about 28x $CO_2$ – but it only persists in the atmosphere for a little more than a decade. The 100-year GWP is used to derive $CO_2e$.
- Source - https://climatechangeconnection.org/emissions/co2-equivalents/

Typically, greenhouse gas (GHG) estimates of gas flaring emissions are based on two core assumptions::

- that flares have a methane destruction efficiency of 98%, resulting in 2% of the methane in the flare gas stream being emitted to the atmosphere un-combusted; and
- that flares are lit and operating properly 100% of the time.

  These assumptions, used widely for decades across the oil and gas industry, have formed the foundation of estimates of GHG emissions from flaring. However, until recently, neither of these assumptions had been rigorously tested in real-world operational environments
- In September 2022, a paper3 was published in Science detailing the findings of a field campaign in the United States to measure flare destruction efficiency. Over several months, researchers sampled the emissions from over 300 flares at onshore oil and gas production facilities in the Permian, Eagle Ford, and Bakken basins. They found that the flares sampled had an average destruction efficiency of 95.2%, considerably lower than the default 98% commonly used. In a complementary study, the researchers also found that 3.2% of the flares assessed in the Bakken were operating unlit, i.e., directly venting gas, including methane, to the atmosphere. Using these findings and building on an earlier study4 in the Permian that found that 5% of the flare assessed were unlit, the study estimates an average of 4.1% of flares may typically be unlit across all three basins.Bringing together the measured destruction efficiency of 95.2% and the prevalence of unlit flares, the researchers suggest that flares in the Permian, Eagle Ford, and Bakken actually operate with an 'effective' destruction efficiency of 91.1%. Source – World Bank Global Gas Flaring Tracker Report MARCH 2023
- Venezuela currently flares/vents ~ 2 Bscfd of natural gas. Source – World Bank Global-Gas-Flaring-Tracker-Report-June-20-2024. It is a safe assumption given the level of disrepair and lack of investments that Venezuela's effective destruction efficiency is < 90%.
- Complete combustion of 1 kg of natural gas produces 2.75 kg of $CO_2$

If venting and flaring result in a mix of 90% complete combustion of methane to $CO_2$ and 10% venting of methane the net effect in terms of $CO_2$ equivalent emission for 1 kg of methane flared/vented is 10.88 Kg of $CO_2$

- Flaring/venting 1 kg of methane will produce =0.90 X2.75 + 0.10 X 84 = 10.88 Kg of $CO_2$
- Current flaring/venting is therefore close to X 4 the emissions of utilizing the natural gas in a process where complete combustion is achieved.
- If all flare/vented gas in Venezuela were to be utilized for ammonia. Methanol , LNG production the annual reduction in $CO_2$ equivalent emissions would be ~ 128 Million MT of $CO_2$ per year. (10.88-2.75) X 21.52 X 365 X 2000 = 127,600,350 MT of $CO_2$ . 1 MMscf of natural gas has a weight of 21.52 MT.