HVDC Transmission Assessment for Expansion of Renewable Energy in La Guajira, Colombia

Task 2 – Selection of HVDC Technology

WORLD BANK

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Executive Summary

World Bank contracted TGS to perform the *HVDC Transmission Assessment for Expansion of Renewable Energy in La Guajira, Colombia* (reference number: 1273214).

The objectives of the project awarded to TGS are:

- to review the initial assessments undertaken by UPME, comparing HVDC technology and HVAC technology for the incorporation of the additional NCRE in the region of La Guajira; and
- to assess different options for the implementation of the HVDC technology including the specification of different associated developments, input and output nodes, voltage level, characteristics, and type of different HVDC technologies based on scenarios for the development of NCRE capacity.

The study comprises of 3 tasks:

Task 1 – Selection of HVDC or HVAC Transmission

Task 2 – Selection of HVDC Technology

Task 3 – Project Execution Considerations

This report presents the outcomes of Task-2. This task identified the technical requirements and the high-level economic factors of the proposed 3000 MW HVDC bipole system to facilitate the integration of the renewable generation in the La Guajira area of into the Colombian AC network. Two interconnection locations were evaluated:

- HVDC terminal at Cerromatoso
- HVDC terminal at Primavera

The steady state power flow analysis and the transient stability analysis were performed for study years 2028 (2000 MW transfer) and 2032 (3000 MW transfer) using DIgSLENT Powerfactory. The outcome is summarized below:

Proposed technology

Considering the amount of renewable generation added and significantly weak AC network, it is recommended to consider the MMC VSC technology for this project. Based on the technical evaluation, the following features are required:

- Configuration: 3000 MW VSC HVDC bipole with the metallic return
- Converter configuration: Half bridge MMC converters with AC breakers (for DC fault clearing)
- Recommended DC Voltage Level: 600 kV
- Recommended interconnection option: DC overhead line from Collector 2 to Primavera
- Additional equipment: A DC chopper would be required to regulate the DC voltage during inverter side DC faults. Note that DC choppers are commonly used in VSC HVDC systems connected to offshore wind farms.

- Control philosophy:
    - Considering the significantly weak AC network at the rectifier (Collector 2), it is necessary to operate the HVDC rectifiers in grid forming mode. The studies have shown that the frequency droop-based grid forming technology would be sufficient.
    - The inverter is regulating the DC voltage. As described earlier, the DC chopper helps to regulate the DC voltage during inverter side AC faults.
    - Both rectifier and inverter can control the AC terminal voltage.
- Converter current rating: Considering the need of grid forming controls, a converter current rating of about 1.2 pu would be required. During the pole outage a short term transient current rating of about 1.3 pu for 1 to 2 seconds would be required. These requirements need to be verified using an EMT study (refer to the additional studies defined below).

AC system adjustments related to HVDC operation

- In order to maintain the uninterrupted power supply during a HVDC pole outage, a single circuit 500 kV AC connection between Collector 1 and Collector 2 is required. Under normal conditions, this line is very lightly loaded.
- A cross tripping scheme for the 500 kV AC line reactors should be implemented during the pole and bipole outages. The studies showed that the 500 kV system voltage significantly drops when a large amount of power is transferred from Collector 2 to Collector 1. The voltage profile improves significantly when the reactors are cross tripped.

  An alternative way of improving the transient voltage performance of the 500 kV parallel AC transmission network (instead of cross-tripping the reactors) is to install dynamic reactive power compensation devices such as STATCOM and SVC. It is recommended to perform a detailed study to evaluate the reactive power compensation in the AC system for different operating conditions including the heavy loading conditions during an HVDC pole outage.

Proposed HVDC terminal

- Considering the technical performance described below, Primavera has been identified as the best location for the HVDC terminal in the south.

Steady state system performance

The power flow analysis showed that the AC system losses are significantly lower for the option of HVDC terminal at Primavera. Although there are higher DC line losses for the Primevera option due to the longer DC line, there is less total loss when considering AC line loss because the load centers are closer to Primevera than Cerromatoso. The losses are compared in the following table.

Year	Study Case	AC system Losses without HVDC (MW)			HVDC system losses (MW)		
		Cerromatoso	Primavera	∆ AC Losses	Cerromatoso	Primavera	∆ DC Losses
2028	Min Dem Min Gen	158	153	5	67.2	72.6	-5.4
	Max Dem Max Gen	420	363	57			
2032	Min Dem Min Gen	206	187	19	101.4	113.4	-12
	Max Dem Max Gen	428	365	63			

The steady state contingency analysis (system intact and N-1) has shown that there are some AC system upgrades required to avoid overloads and voltage violation issues. Note that UPME has already identified some of the system upgrades. It was also observed that less upgrades are required for the option of HVDC terminal at Primavera. A summary table is provided below:

Equipment Overflow	VSC HVDC interconnection location	
	Cerromatoso	Primavera
Transmission lines		
Nueva Esperanza - Río 115 kV	Upgrade required	Upgrade required
Porce III - San Carlos 1 500	Upgrade required	-
Bacata - Suba 1 115	-	Upgrade required
Transformers		
Chinu 1 500/110 Chinu 2 500/110 Chinu 3 500/110	Upgrade required	-
La Virginia 500/230	Upgrade required	-

Transient stability performance

The transient stability analysis carried out for critical N-1 contingencies showed that the system performance meets the study criteria for both 2028 and 2032 study years. The performance criteria in the Colombian grid code defined for transient voltage and frequency recovery were fully satisfied. All the generators remained in synchronism. No load shedding was observed.

For the HVDC pole outages, it was necessary to have a short term transient current capability for the HVDC converters of about 1.3 pu for 1 to 2 seconds. Furthermore, it is required to cross-trip the 500 kV line reactors as described above. With these changes, the full amount of renewable generation in Collector 2 can be delivered without any interruption during a pole outage.

A Sensitivity analysis was performed to assess the system transient performance of the proposed interconnection option (VSC HVDC connected to Primavera) with the high renewable energy penetration in Sahagun area using the *Med Dem Max Gen* study cases for operational years 2028 and 2032. The transient stability analysis carried out for key contingencies showed that the system performance meets the study criteria for both 2028 and 2032 study years. Similar system performance and the requirements for the HVDC pole outage were also observed.

It is necessary to cross trip a large amount of renewable generation during a bipole outage. It is difficult to determine the exact amounts of generation trip at this stage due to the limitations in RMS simulation tools. An accurate estimation can be determined during the design stage using EMT simulations.

In general, the electromechanical oscillations of the system are well damped and there is no concern about the small signal stability. The grid forming control concept of the HVDC worked well and no adverse interactions with the AC system was observed.

High level cost comparison

A high-level economic analysis was performed to evaluate the interconnection options: 1- DC overhead line to Cerromatoso, 2- DC overhead line to Primevera and 3- DC cable + overhead line to Cerromatoso. A summary of the cost comparison is provided below. The analysis showed that the Option 2- DC overhead line to Primevera is the most economical interconnection option.

Option	Description	Cost of Converter (Mil USD)	Cost of Line+Cable (Mil USD)	Cost of ROW (Mil USD)	Cost of Losses (Mil USD)	Total Cost (Mil USD)
1	Overhead line to Cerromotoso	1275	214.5	65	730	2285
2	Overhead line to Primavera	1275	257.4	78	521.3	2132
3	Overhead+submarine to Cerromatoso	1275	1846	15.1	916.5	4053

Recommendations

Additional studies

Considering the complexity of the project, involvement of large amount of power electronic based devices (wind, solar, HVDC etc.) and the weak AC connection at the rectifier, it is recommended to perform an additional electromagnetic transient (EMT) study to verify the specific requirements and modifications identified for the HVDC system and the AC network. This needs to be carried out before releasing the specification. The modelling details and the cases to be considered are summarized in this report (Section 5.4).

The studies found that it is necessary to cross trip the 500 kV line reactors after an HVDC pole outage in order to maintain the voltage stability of the system. Alternatively, dynamic reactive power compensation devices such as STATCOMs and SVCs may produce the required support. It is recommended to perform a detailed study to evaluate the reactive power compensation in the AC system for different operating conditions including the heavy loading conditions during an HVDC pole outage.

Project Implementation Aspects

The requirements of this project (MW rating and DC voltage rating) are pushing the available VSC HVDC technology to its limits. The 3000 MW rating for a VSC bipole is only available in China and the most common rating in the rest of the world is about 2000 MW. The most common DC voltage that can be used for both overhead and cable transmission is 525 kV. Our inquiries with the manufacturers have revealed that 3000 MW rating at 600 kV is still achievable but the cost would be high. If it is necessary to have a 600 kV DC cable section, only few manufacturers have the capability. Therefore, considering these facts, UPME may consider a lower rating for this project. An HVDC of 2000 or 2500 MW at 525 kV can be achieved using commonly available technology at present.

TGS also recommends the consultation with HVDC vendors to determine the feasibility, alternatives, and the economic impact of the project.

1. Introduction

World Bank contracted TGS to perform the *HVDC Transmission Assessment for Expansion of Renewable Energy in La Guajira, Colombia* (reference number: 1273214).

Since 2014 Colombia aimed to increase its electricity generation capacity with non-conventional renewable energy sources (NCRE). Over the last two years, the country has embarked on the design of tailor-made public interventions, incentives, and policies, including electricity auction schemes.

The country has recently auctioned and signed public purchase agreements (PPAs) for the construction of over 2200 MW of solar and wind generation before the end of year 2022. Taking this into account, transmission expansion works have already been defined and awarded to enable the connection of such projects. In addition, nearly 7000 MW consisting of mainly wind and solar potential projects have received regulatory approval in the country.

Given the above projects, the high potential for additional generation and new tenders (mainly in La Guajira, Cesar, and Magdalena) the capacity of the existing network needs to be increased. This led Colombia's Unit of Mining and Energy Planning (Unidad de Planeación Minero Energética – UPME) to analyze the alternatives for new transmission infrastructure to facilitate the interconnection of additional generation projects, particularly from La Guajira region. The expansion plan includes adding about 3000 MW of wind and solar power plants in the La Guajira region at the collectors 2 and 3 in the La Guajira region as shown in Figure 1-1. UPME is exploring AC and DC transmission options from the La Guajira region (Collector 2) to the load centers. The transmission system length from the La Guajira region to the potential interconnection locations is approximately 520—780 km.

The objectives of the project awarded to TGS are:

- to review the initial assessments undertaken by UPME, comparing HVDC technology and HVAC technology for the incorporation of the additional NCRE in the region of La Guajira; and
- to assess different options for the implementation of the HVDC technology including the specification of different associated developments, input and output nodes, voltage level, characteristics, and type of different HVDC technologies based on scenarios for the development of NCRE capacity.

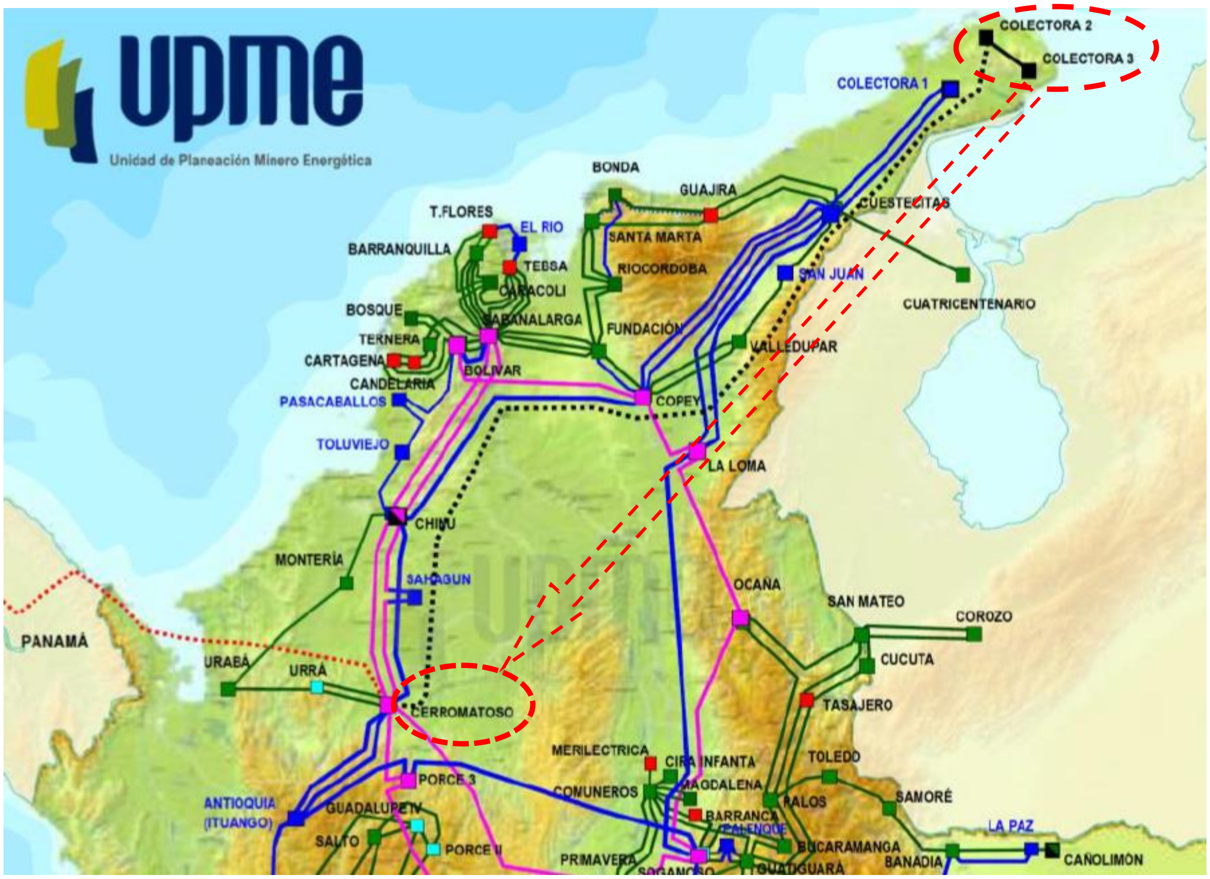


Figure 1-1: Renewable Energy Expansion Plan in Colombia [1]

The study comprised of three main tasks.

Task 1 – Selection of HVDC or HVAC Transmission

Task 2 – Selection of HVDC Technology

Task 3 – Project Execution Considerations

The following two steps were completed under Task 1 (Refer report: Task 1 – Selection of HVDC or HVAC Transmission [2]).

Step 1 – Review UPME reports and analysis

Step 2 – Additional studies to validate the selection of HVDC over HVAC

As described in Task 1 report [2], the HVDC option has been identified as the most suitable energy transmission option for this project. In this report, the selection of HVDC technology (Task-2) is evaluated in detail.

The objectives of Task 2 are:

1. Analyze and present the pros and cons of different technology options for the implementation of an HVDC project.

2. Conduct further studies of the power system model with the proposed HVDC system:
    - Steady state performance assessment
    - Transient stability performance assessment
    - Identification of required network AC network upgrades
3. Perform an economic and financial assessment of the technically feasible solutions.

In the Task 1 study report (Refer report: Task 1 – Selection of HVDC or HVAC Transmission [2]), the pros and cons of different HVDC technologies (item number 1 above) are analyzed. For completeness, selected sections from the Task 1 study report are repeated in this report.

The scope of objective 2 (detailed evaluation of HVDC options) was expanded during the study based on UPME’s request. The detailed system studies were performed for two HVDC interconnection locations: Cerromatoso and Primavera.

2. Proposed Solution—VSC HVDC Bipole

The feasibility of transmission options to integrate the renewable generation at Collector 2 were studied in Task 1 and the Modular multi-level Voltage Source Converter (MMC VSC) HVDC bipole technology was proposed as the most suitable solution (refer Task 1 report [2]).

This chapter presents the details and the requirements of the proposed 3000 MW VSC HVDC bipole system.

2.1 VSC HVDC configuration

2.1.1 Available HVDC Transmission Configurations

The HVDC configurations for long distance power transmission are available in monopolar or bipolar systems. Some of the most common configurations are outlined below.

Monopole Configurations

Monopole systems use one HVDC converter per each station. There are few possibilities:

Asymmetrical monopolar HVDC schemes with a ground return use only a single high voltage conductor line or cable (Figure 2-1). However, it is very difficult to use continuous ground return because of the environmental concerns. Therefore, the systems with a metallic low voltage conductor is (Figure 2-2) is the most realistic asymmetrical monopole configuration.

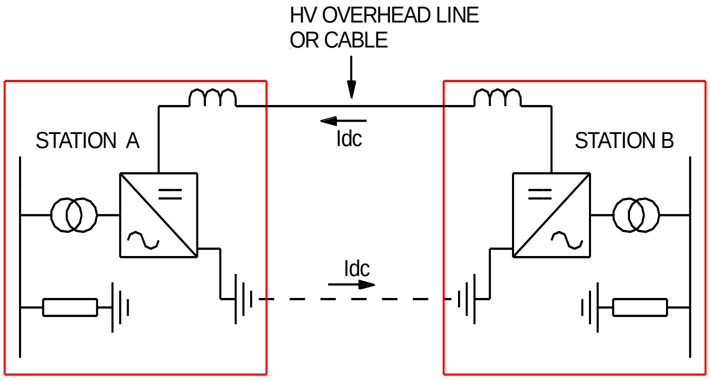


Figure 2-1 Monopolar point to point HVDC scheme with earth return

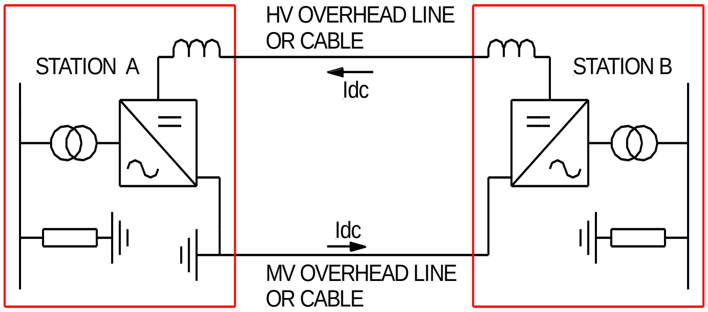


Figure 2-2 Monopolar point to point HVDC scheme with metallic return

The most popular monopole configuration is the symmetrical monopole configuration as shown in Figure 2-3. In this case two high voltage conductors, one positive polarity and the other negative polarity are used. One advantage of this configuration is that the DC offset of the converter transformer is zero and therefore regular power transformers can be used for that purpose.

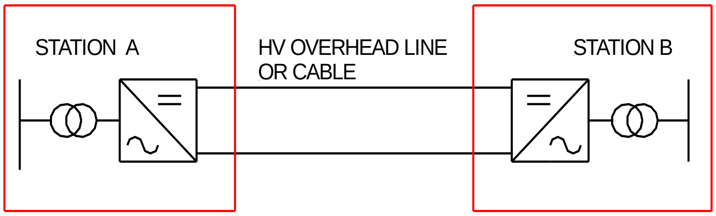


Figure 2-3 Symmetrical monopole configuration

Bipole Configuration:

The most common configuration is Bipolar HVDC scheme. A bipolar scheme uses two high voltage conductors of different polarity (Figure 2-4). Bipolar schemes can employ electrodes for periods of unequal pole currents, or for emergency operation when one of the poles is out of operation or be equipped with a dedicated metallic return (DMR). With a DMR, the grounding is made only at only one terminal (Figure 2-5). However, in many bipolar systems, monopolar operation can also be performed utilizing the out of service pole conductor as a return path referred to as permanent metallic return (PMR). For PMR monopolar operation, the converter stations must be designed for it.

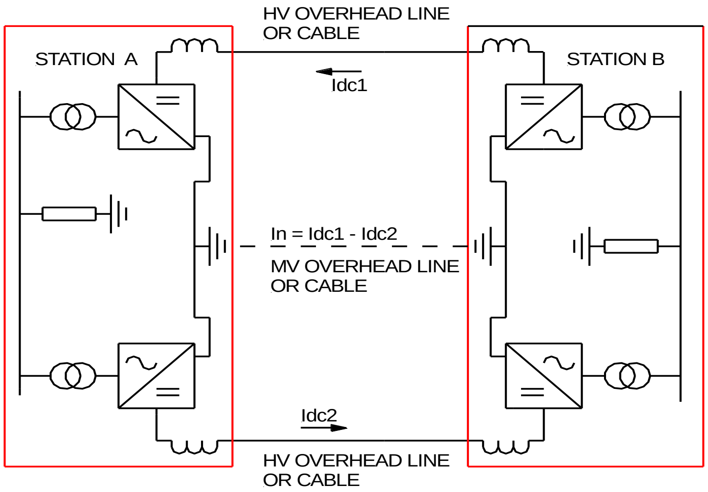


Figure 2-4 Bipolar point to point HVDC scheme with electrodes

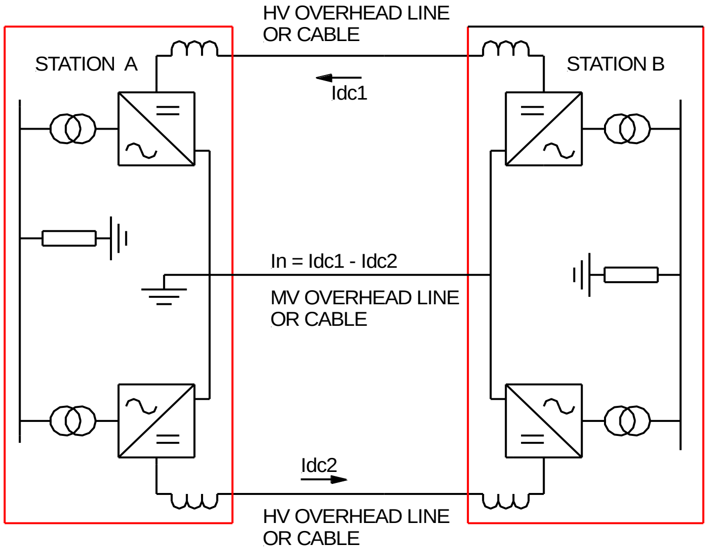


Figure 2-5 Bipolar point to point HVDC scheme with DMR

2.1.2 Selection of the HVDC Transmission Configuration

Following are the considerations for the section of the HVDC configuration:

- The entire power transfer in a monopole configuration is interrupted using a converter or a DC line outage (i.e., a pole outage). In contrast, bipole systems are designed in such a way that an outage of one pole does not affect the other pole. Therefore, a pole outage in a bipole system provides about 50% of the nominal power transfer capacity in the healthy pole. If technically and economically feasible, the system can also be rated for short term or long-term overloaded operation to minimize the impact of a pole loss.

- Considering the complexity and the short circuit strength of the collector system (as described in Task-1 report), VSC HVDC technology is required for this project.

- For 3000 MW power transfer, either one VSC bipole system or two VSC monopole systems are required. The option of two symmetrical monopoles would be obviously more expensive than a bipole system.

- The ground return is not considered as an environment friendly option due to corrosion and other interference effects. Therefore, a dedicated metallic return (DMR) is proposed.

Considering these facts, a VSC HVDC bipole with the metallic return was proposed for this project.

2.1.3 Selection of the VSC Converter Configuration

HVDC transmission systems may use overhead lines. HVDC overhead lines are subject to DC line faults for a variety of reasons. DC line faults are typically non-permanent. One of the major advantages of HVDC transmission is the ability to restart following DC line faults, further, the ability to restart at reduced dc voltage in the range of 80% of nominal dc voltage to overcome pollution related dc line faults. Basically, following a dc line fault, a fault deionization period is initiated by setting both the dc voltage and the dc current to zero. Following a preset period, the transmission can be restarted either at full voltage or reduced voltage. The performance of the VSC systems under DC line faults depends on converter configuration. The following options are available:

- Half bridge multi-level converter (MMC) VSC:

  The half bridge converters do not have the ability to clear dc line faults without tripping of the converter AC breakers. For a DC line fault, the converter is blocked as soon as the fault is detected, however, the AC system will feed the DC fault through the free-wheeling diodes (looks like an AC fault from the AC side). The fault current has to be extinguished by tripping the converter AC breakers. However, the opening of the AC breakers, followed by a fault deionization period, followed by re-energization and deblock of the converter can be as long as 1 second. Such a long time can have an impact on the connected AC system. If high speed fault clearing is required, the alternative is a high-speed DC breaker (ultra-fast electronic switch). The fast DC breakers can be used to quickly extinguish the DC fault current in the range of 10ms. However, there are costs associated with the breaker that should be considered

- Full bridge modular multi-level converter (MMC) VSC:

  The full bridge MMC converter is capable of extinguishing DC line faults. The fault current can be controlled to zero without blocking the converter (DC fault current control logic). In terms of the controllability, a full bridge MMC converter would be the best option. The power transfer can be quickly restarted, and any number of restart attempts can be programed easily. However, the cost of the converters is higher than half bridge converters and the losses are also higher than a half bridge solution.

Considering the options:

- Half bridge converter with AC breaker for DC fault clearing
- Half bridge converter with fast DC breaker for DC fault clearing
- Full bridge converter with controlled DC fault clearing logic

the most cost-effective solution is half bridge converters with AC breakers.

Figure 2-6 shows a simplified diagram of the proposed VSC HVDC bipole system.

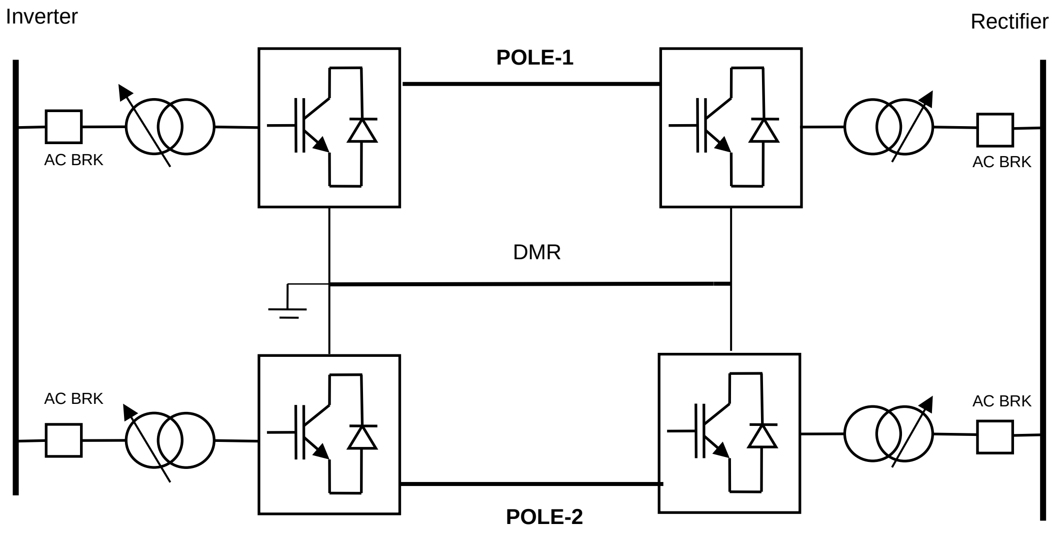


Figure 2-6 Simplified diagram of a VSC HVDC bipole system

2.2 Review of Recommended Voltage Levels

The HVDC power rating is 3000 MW. Considering the present state of the VSC valve ratings, it is clear that the DC voltage cannot be any lower than 500kV for a bipolar system. If +/- 500 kV is considered, the DC current is 3 kA. This rating is only available from certain manufacturers. To reach 3000MW rating at 500 kV, obviously one can utilize parallel valves, or converters or IGBTs. However, this would be a complicated and expensive solution. In our opinion a better alternative is to increase the DC voltage above 500 kV. UPME proposed 550 kV, this results in a DC current of 2.7 kA. Considering that the project is to be realized within 5 years, the indication in the industry is that a 2.8 kA current rating will be available. Therefore 550 kV is a viable option. If we consider a bipole at +/- 600 kV the DC current is 2.5 kA. Certainly, this is available considering the present converter ratings. Increased DC voltage will reduce the DC line losses. Obviously, there may be increase in the cost of the DC line and the converter at 600 kV compared to 550 kV.

2.3 Technical Feasibility of DC Rating

For the evaluation of the DC rating a 3000 MW VSC bipole with a DC voltage of +/-600 kV is considered. The rated DC current is 2.5 kA. If a nominal modulation index of 0.9 is considered, the expected valve side AC voltage is about 330 kV. Therefore, the rated AC current is about 2.62 kA.

The steady state peak current through the HVDC converter can be obtained from:

$$I_{valve,pk} = \frac{Iac,pk}{2} + \frac{Idc}{3} = 2.69\ kA$$

The steady state peak current through the valve is about 2.69 kA (considering the peak of AC current). The IGBTs available in the market are capable of handling this current. Therefore, there is no technical roadblock related to the DC current raring.

2.4 Considerations Related to HVDC Pole Outage

The system operating conditions under a HVDC pole outage play a key role in the design of a new HVDC system. Usually, in AC transmission lines, the thermal rating is much higher than the actual power transfer under system intact conditions. Therefore, during a circuit outage of a double circuit AC transmission line, the healthy circuit is capable of temporarily transmitting most of the pre-contingent power. In contrast, due to the cost of equipment and technical limitations, HVDC systems are usually designed to be operated at the rated power transfer in normal conditions. Therefore, during a pole outage, overloading the healthy pole to carry a large amount of excess power is not possible. HVDC systems typically have an overload capacity of about 10%. If additional overloading capability is required, the ratings of the equipment must be increased (technology permitting) at the design stage and this will add additional cost. Usually, it is expensive to have addition overload capabilities in a VSC HVDC system.

The pole outage is an n—1 operating condition. Usually, the grid codes do not allow load shedding under n—1 operating condition.

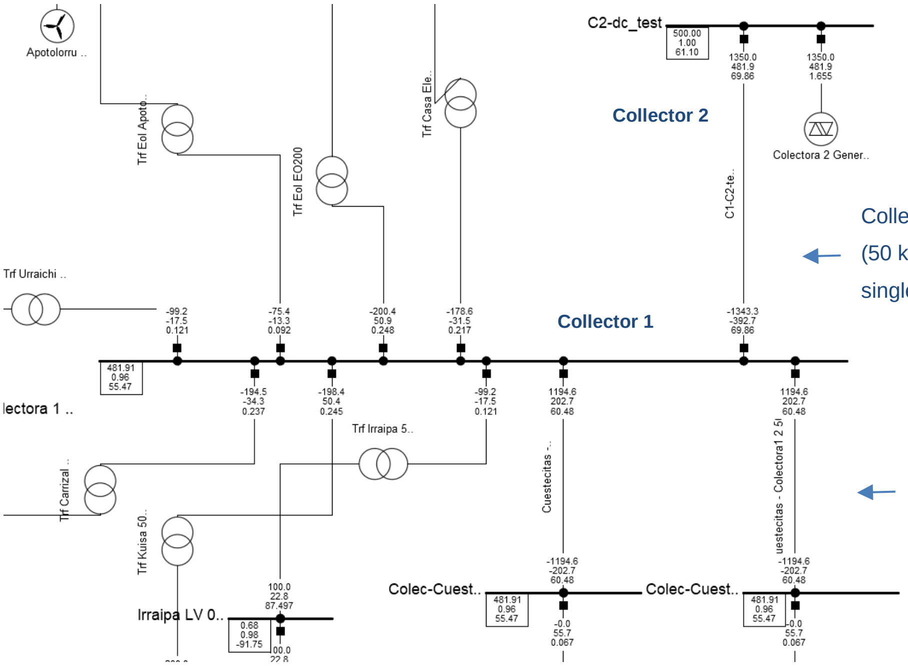
2.4.1 Compliance to the Colombian Grid Code During the Pole Outage

The Colombian grid code states that the system should be capable of transmitting the generation to the loads under all n—1 operating condition. The only path to transmit the Collector 2 generation to the Colombian grid is the VSC HVDC. Under a HVDC pole outage, a portion of the renewable generation connected to Collector 2 will have to be tripped due to the power transfer limitation of the healthy HVDC pole. However, the generator tripping under an n—1 contingency violates the Colombian grid code. It is also not economical to consider a 100% overload capability for the VSC HVDC system. Therefore, an additional AC path was considered by interconnecting Collector 1 and Collector 2.

2.4.1.1 Interconnection of Collector 1 and Collector 2

The studies were performed to assess the feasibility of transmitting the excess power, during an HVDC pole outage, to the AC system via a 500 kV single circuit interconnection between Collector 1 and Collector 2.

During a pole outage, the healthy pole is capable of transmitting about 1650 MW to south (with a 10% overload capability). The generation tripping can be avoided if the remaining 1350 MW can be transferred to the AC system via the connection from Collector 1 to Collector 2. Figure 2-7 shows the network power flow between Collector 2 and Collector 1 during the pole outage in the *2032 Max Dem Max Gen* study case.



Collector 1—Collector 2 interconnector
(50 km long 500 kV
single circuit transmission line)

Collector 1—Cuestecitas 500 kV
double circuit transmission line

Figure 2-7 Collector 2 to Collector 1 Power flow during a HVDC pole outage (2032 Max Dem Max Gen)

The steady state analysis showed that the system is capable of transmitting the power to the south without overloading major transmission lines or other equipment. For example, under these conditions, the double circuit 500 kV transmission lines from Collector 1 to Cuestecitas is only loaded to about 61% of its thermal rating.

For the pole outage in 2028 study cases, only 350 MW need to be transmitted via the proposed Collector 1—Collector 2 interconnector (the healthy pole is capable of transmitting 1650 MW). The analysis showed that the system is capable of transmitting the power to the south without thermal limit violations of major transmission lines or other equipment.

The study results presented in this section show that the generation tripping due to the HVDC pole outage can be avoided if Collector 1 and Collector 2 are connected using a 500 kV single circuit transmission line. This line will be lightly loaded during the normal operating conditions and will be loaded up to approximately 70% of its thermal rating during an HVDC pole outage.

2.5 The need of Grid Forming Capability

The inverter side of the VSC HVDC is connected to a very weak AC connection. Therefore, the grid following mode of operation of the HVDC rectifier would be challenging. Furthermore, when the proposed 500 kV circuit between Collector 1 and Collector 2 is tripped, Collector 2 and the rectifier are isolated from the rest of the AC grid. Therefore, the VSC HVDC should be operated in grid forming mode.

2.6 Review the Recommended Terminals of the Line—Chinnu, Cerromatoso and Primavera

Cerromatoso and Chinu are about 135 km apart. The network power flow for 2032 study cases were compared with the HVDC connected to Cerromatoso and Chinu. The left and right figures in Figure 2-8 and Figure 2-9 show the network power flow when the HVDC (3000 MW) is interconnected at Chinu and Cerromatoso respectively.

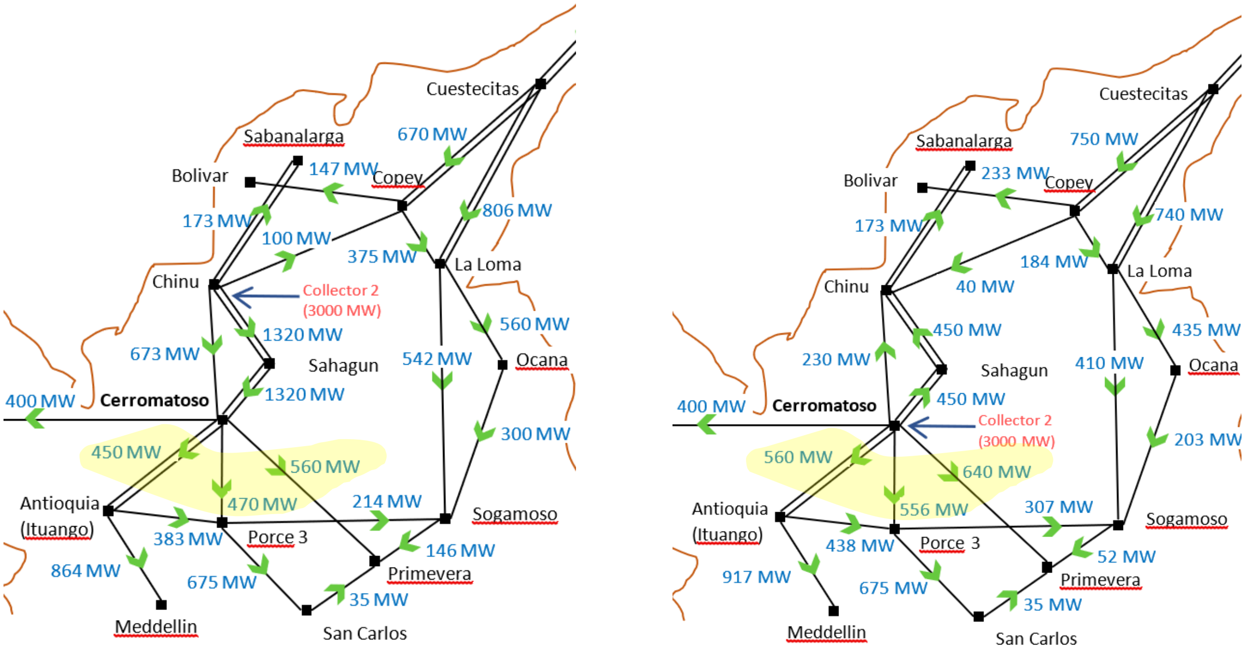


Figure 2-8 Network power flow based on the Collector 2 interconnection location in *2032 Min Dem Min Gen* study case (Left: at Chinu, right: at Cerromatoso)

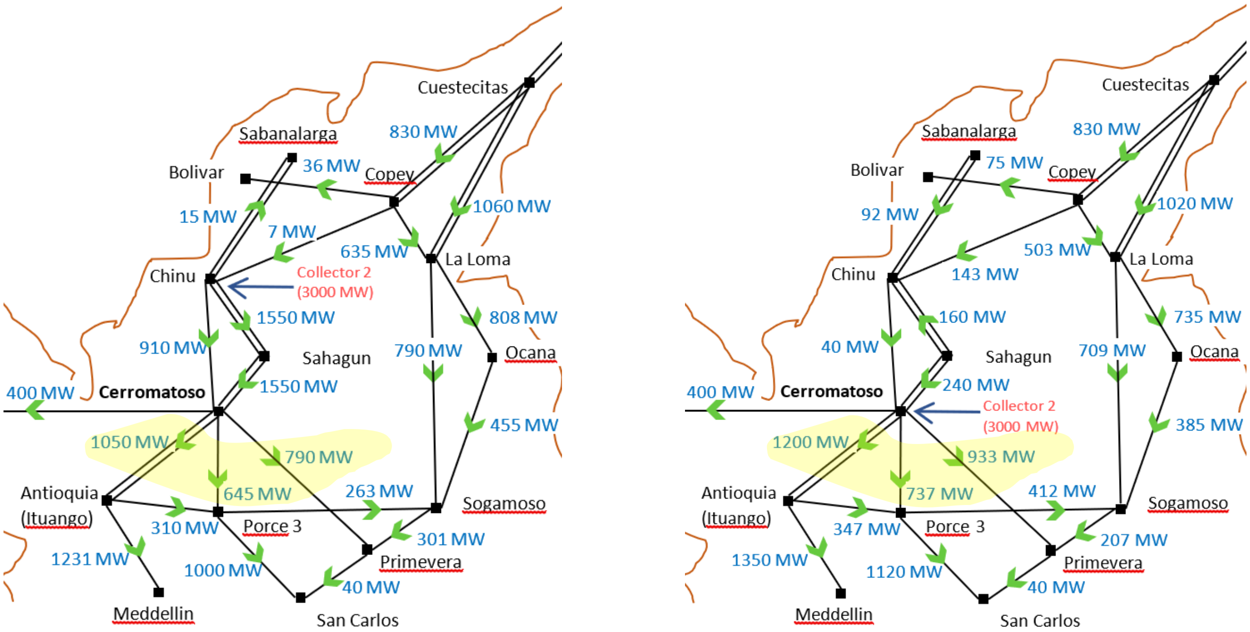


Figure 2-9 Network power flow based on the Collector 2 interconnection location in *2032 Max Dem Max Gen* study case (Left: at Chinu, Right: at Cerromatoso)

The following observations were made:

- The load centers are south of Cerromatoso. Therefore, when interconnected at Chinu, the power needs to be transmitted for about 135 kms from Chinu to Cerromatoso using the 500 kV AC transmission lines. The highlighted power flows in Figure 2-8 and Figure 2-9 show the similarity of the power flowing south from Cerromatoso (Antiuquia, Porce and Primevera) irrespective of the interconnection location. Accordingly, the selection of Cerromatoso will result in lower transmission losses.
- The system strength at Cerromatoso is higher than Chinu in all study cases and will be a better location for interconnection in terms of the overall system stability.

Based on the above observations, when Chinu and Cerromatoso stations are compared, the Cerromatoso 500 kV station would be a better location as the HVDC terminal.

Our further investigations revealed that most of the power coming from the HVDC terminal is moving further south of Cerromatoso. With the agreement of UPME, it was decided to evaluate the feasibility of 500 kV Primavera substation as the HVDC terminal.

Table 2-1 shows the AC system strength and losses (without HVDC transmission system losses) when Collector 2 is interconnected at Cerromatoso and Primavera. Note that for 2028 scenarios only 2000 MW of generation at Collector 2 was considered. The system losses were obtained for the entire power system considering all voltage levels.

Table 2-1 AC system strength and losses (without HVDC) when Collector 2 is interconnected at Cerromatoso and Primavera

Year	Study Case	System Strength (MVA)		Losses without HVDC (MW)		
		Cerromatoso	Primavera	Cerromatoso	Primavera	Δ Losses
2028	Min Dem Min Gen	13147	12989	158	153	5
	Max Dem Max Gen	17725	14188	420	363	57
2032	Min Dem Min Gen	13951	12697	206	187	19
	Max Dem Max Gen	17730	15083	428	365	63

The AC system strength at Primavera is sufficient to absorb the VSC HVDC power transfer. Moreover, the AC system losses are significantly lower when the interconnection is at Primavera. The HVDC transmission line to Primavera will be about 780 km long (about 150 km longer than to connect at Cerromatoso). Therefore, the HVDC transmission losses will be more when the interconnection is at Primavera than at Cerromatoso. The additional DC transmission losses are expected to be about 15 MW and this amount is still lower than most of the loss differences shown in Table 2-1.

Figure 2-10 shows the comparison of power flow when the Collector 2 is connected at Cerromatoso and Primavera for the *2032 Max Dem Max Gen* scenario which has the largest difference in AC system transmission losses (refer Table 2-1). The highlighted power flows in major transmission lines south of Cerromatoso are less loaded which is the main reason for the reduced AC transmission losses.

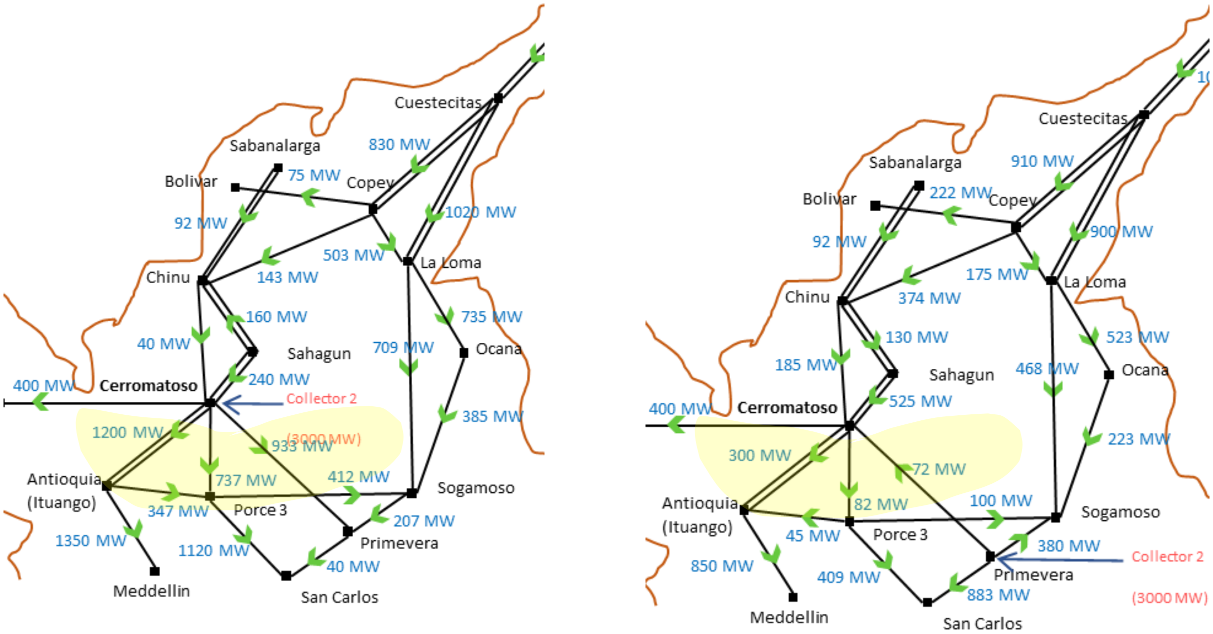


Figure 2-10 Power flow comparison-Collector 2 interconnected at Cerromatoso vs Primavera (2032 Max Dem Max Gen)

Based on this analysis, when Cerromatoso and Primavera stations are compared, it is recommended to select Primavera 500 kV station as the terminating station for the proposed VSC HVDC system.

Primavera is expected to be a congested area as it is located very close to Bogotá. There may be non-technical constraints for constructing a converter station such as space limitations. It is recommended for UPME to further evaluate the feasibility of Primavera as the HVDC converter station.

2.7 Consideration of Panama HVDC link

At the time of this study, the device dynamic models for proposed Panama HVDC link were not available and the Panama HVDC was modeled as a 400 MW load connected to Cerromatoso. It is recommended to perform a detailed HVDC interaction study at the design stage of Panama HVDC including detailed HVDC models.

2.8 Summary – Proposed Solution

Based on the technical evaluation, the following solution is proposed:

- Half bridge MMC VSC bipole system rated at 3000 MW with +/- 600 kV DC voltage.
    - Grid forming operation for rectifier (Collector 2 side)
    - Cerromatoso or Primavera as southern HVDC terminal (inverter)
    - DC fault clearing using AC breakers
- 500 kV single circuit AC interconnection between Collector 1 and 2.

UPME requested to perform the system studies for both Cerromatoso and Primavera stations as the HVDC terminals. The next chapter presents the results of the system studies performed for the interconnection at both locations.

3. System Studies

This chapter presents the methodology and study results for the detailed power system studies performed for the interconnection of renewable energy generation in the La Guajira area into the Colombian power system using a 3000 MW half bridge VSC HVDC bipole system. The studies were performed for two interconnection locations in the south—Cerromatoso and Primavera.

3.1 VSC HVDC Representation

TGS inhouse developed VSC HVDC Model in DIgSILENT was used to model the HVDC system. The following details are included in the model.

- Converter technology - Half bridge Modular multi-level converter (HB MMC)
- Converter topologies - Bipole with metallic return (BPMR)
- DC transmission system (DC overhead line with dedicated metallic return)
- The converter model in each terminal of each pole contains the MMC valves, phase reactor, DC smoothing reactor, converter transformer with tap changers and the AC breakers.
- Since the rectifier AC system is weak, a DC chopper would be required to control the DC over voltages during the inverter side AC faults. This requirement needs to be evaluated using an EMT simulation in a later stage (as described in Section 5.4). In the DIgSILENT model, a simple chopper model with a resistor and a series switch is used.
- Each DC line is modeled with two sections: a cable section and an overhead line section.
- Each converter will be assigned a converter control model, which determines the AC current injections, DC voltage, power losses and the controls for the DC chopper.

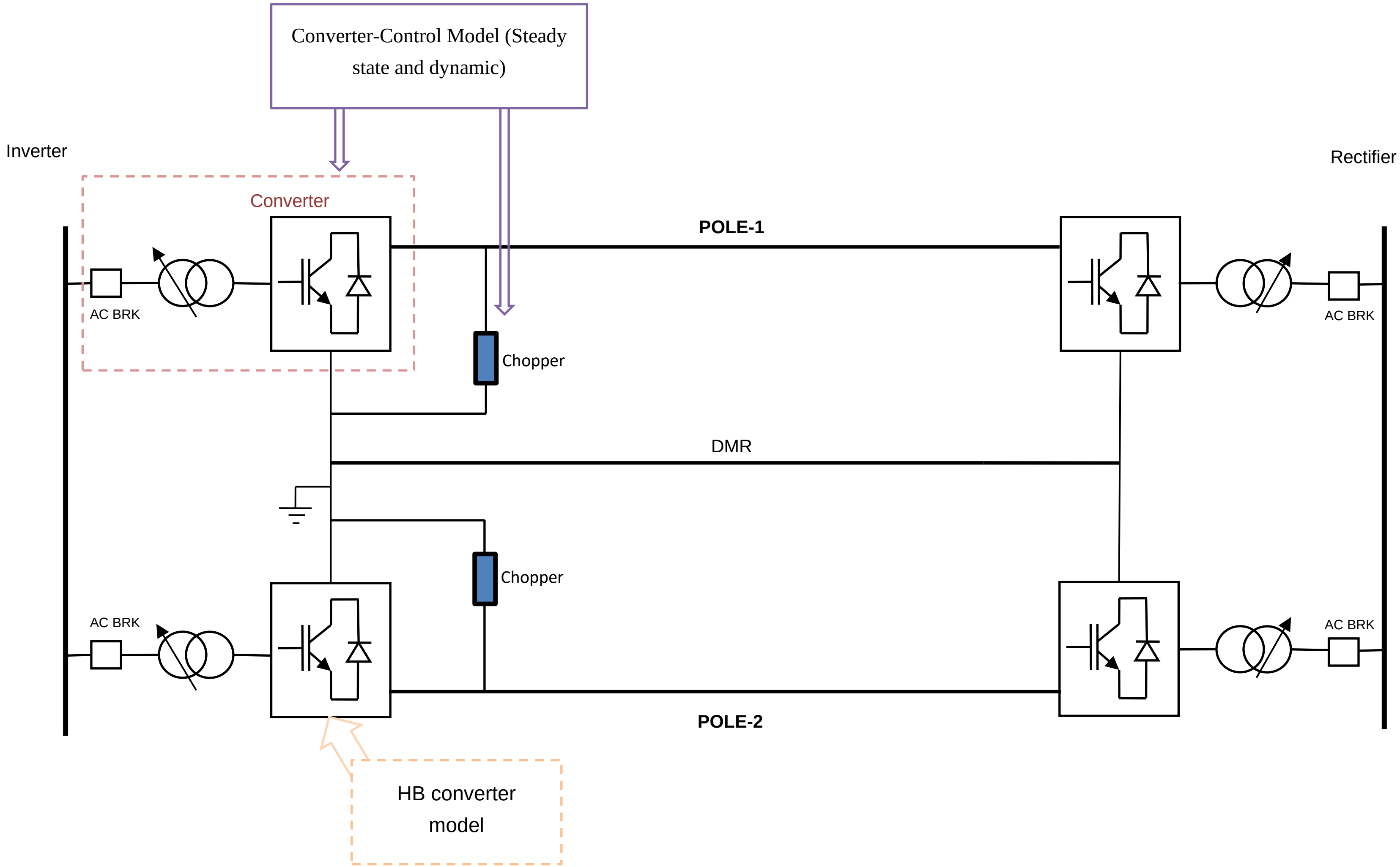


Figure 3-1: HVDC model in DIgSILENT

3.1.1 Steady State Model

The AC interface of each converter is modeled using a static generator (“ElmGenstat”) model. The P-Q capability of the converter is defined through Reactive Power Operational Limit curve stored in a library. The limits are automatically adjusted based on the MVA rating defined in the model. Typical P-Q capabilities (i.e., 0.5 pu reactive power limit at zero power and 0.3 pu reactive power limit at rated power) were considered in this study. A station controller attached to each AC terminal is used to control the AC terminal voltage.

The converter losses and station services are modeled using a 20 MW load connected at each terminal.

3.1.2 Transient Stability Model

The transient stability model was developed using an external DLL type model for the converters and their controllers. The IEC61400-27-1 DLL interface available in Powerfactory allows to model the dynamics of the external model at a smaller time step than the rest of the system model. This feature makes it possible to model the fast converter controls without any simplifications.

The overall RMS model is depicted in Figure 3-2. There are four instances of the converter-control model DLL used in the model. Each instance of the module determines the AC current injections, DC voltage and the control signals for the DC/AC breakers and Choppers based on the measurements at the relevant terminal.

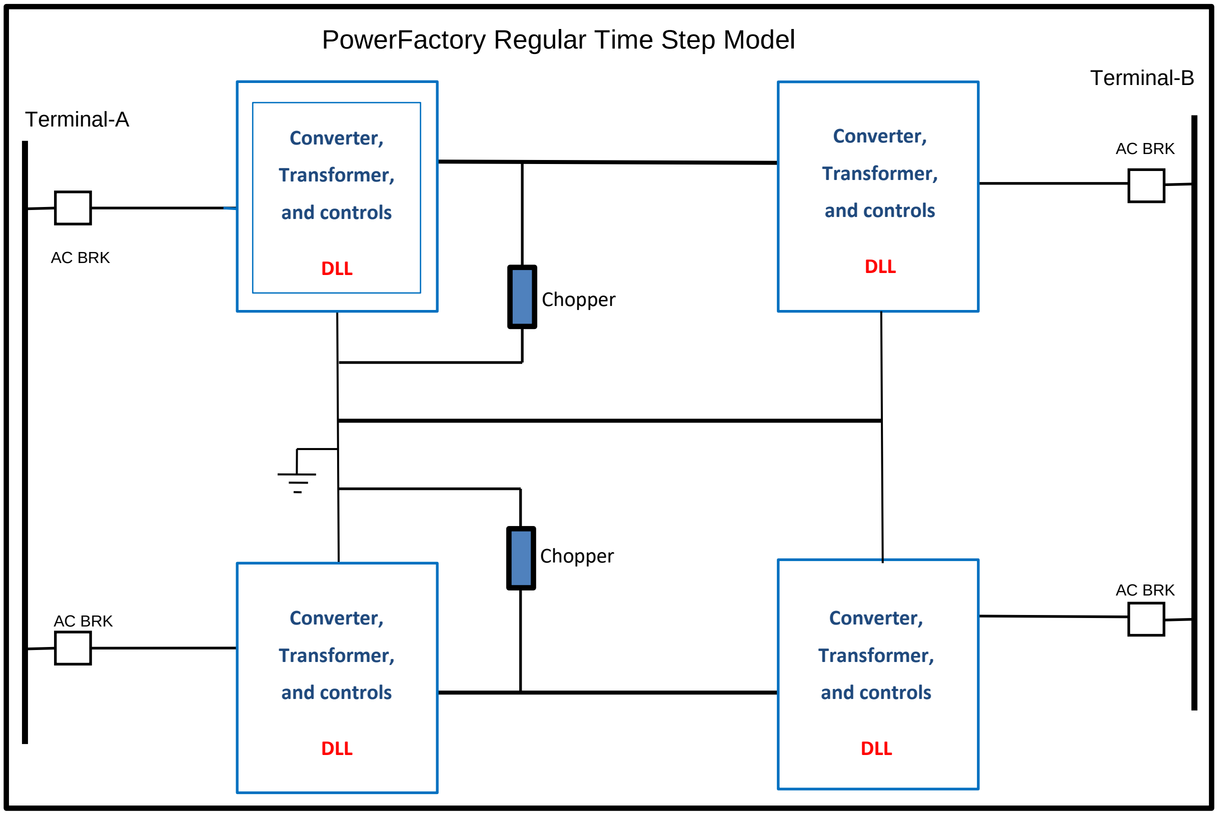


Figure 3-2: RMS Model - Combination of DLL and External System

3.1.2.1 Rectifier Controls

As described in Section 2, the inverter is operated in the grid forming mode of control. A high-level block diagram of the controls is shown in Figure 3-3. The virtual synchronous machine controls with swing dynamics (i.e., with inertia) are used and a governor model with frequency droop characteristics are used to regulate the power transfer. A voltage controller is used to regulate the AC terminal bus voltage. To maintain the converter current within the maximum current limits, a transient current limiting logic is used.

When the grid forming controls are used, there should be some flexibility of the converter currents for the proper operation under transient conditions. Therefore, a larger short-term transient current rating would be required. In grid following converters, the typical current rating is about 1.1 pu. In this case, a current rating of 1.2 pu (for maximum duration of 1 or 2 seconds) was considered for the rectifier terminal.

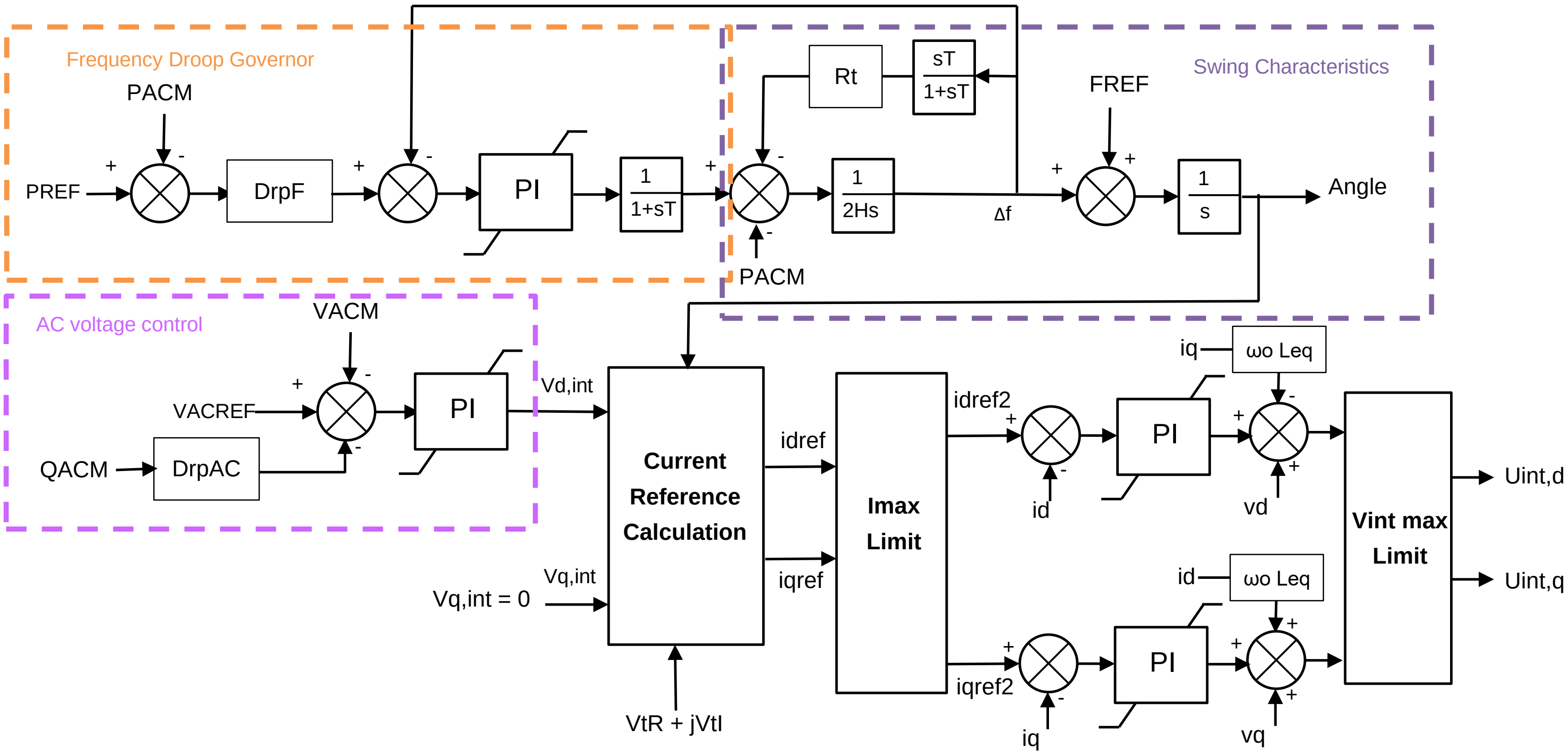


Figure 3-3: Grid Forming Controls

3.1.2.2 Inverter Controls

The grid following mode controller uses dq decoupled controls (i.e., with a phase locked loop) at the inverter terminal. The inverter is regulating the DC voltage such that the rectifier DC voltage is the rated voltage. This can be done using a remote DC voltage measurement and/or using a compounding resistance (usually as a backup). The inverter reactive power is controlled to regulate the AC terminal voltage (i.e., AC voltage control).

The DC chopper is also attached at the inverter terminal. When the DC voltage exceeds a maximum DC voltage threshold, the chopper is activated to regulate the DC voltage. Since the rectifier is operated in grid forming mode, the chopper functionality would be necessary during AC faults at the inverter end. This requirement needs to be further evaluated using EMT simulations as described in Section 5.4.

3.2 System Models and Study Criteria

3.2.1 Study Cases

The four study cases given in Table 3-1, for operational years 2028 and 2032, were used in the analysis. The following modifications were made to the original powerflow cases received from UPME.

- Collector 2 generation was added
- The VSC HVDC system between Collector 2 and Cerromatoso/Primavera was added
- Single circuit 500 kV line between Collector 1 and 2 was added

The study cases already included the transmission network upgrades defined in UPME's latest transmission expansion plan [3]. Only 2000 MW of renewable generation is expected to be connected to the Collector 2 by operational year 2028. The full capacity of 3000 MW is expected to be reached by operational year 2032.

The active power flows in major 500kV network for the HVDC connection at Cerromatoso are shown in Figure 3-4 through Figure 3-7.

Table 3-1 Study cases

Operational Year	Study Case	Collector 2 Generation (MW)	Total System Load (MW)
2028	Min Dem Min Gen	2000	7914
	Max Dem Max Gen		11934
2032	Min Dem Min Gen	3000	8315
	Max Dem Max Gen		12546

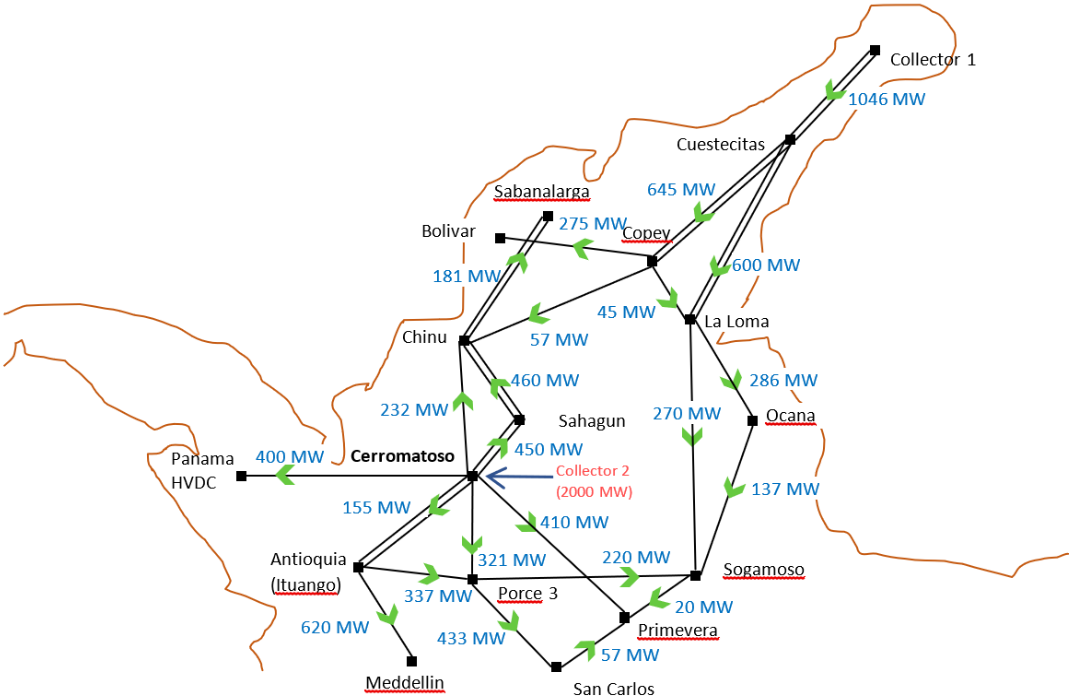


Figure 3-4 Active power flow on selected 500 kV transmission corridors - 2028 Min Dem Min Gen (HVDC connection at Cerromatoso)

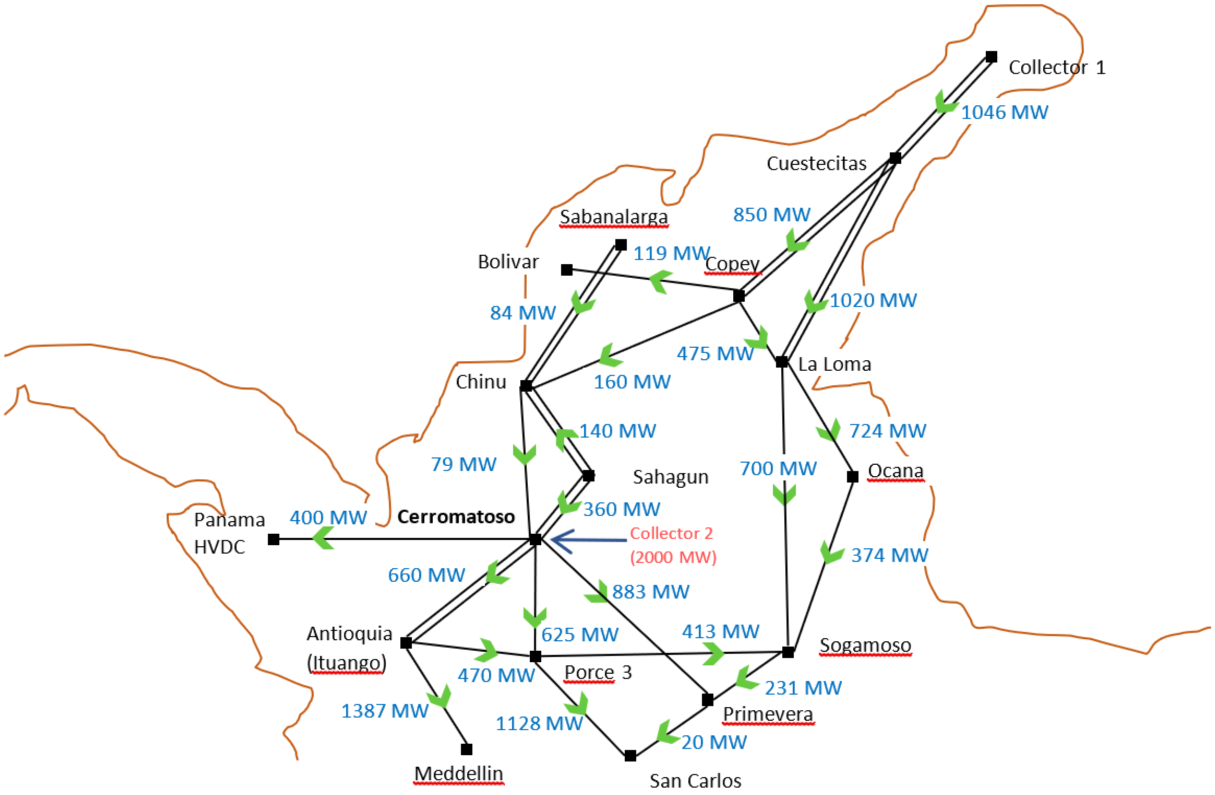


Figure 3-5 Active power flow on selected 500 kV transmission corridors - 2028 Max Dem Max Gen (HVDC connection at Cerromatoso)

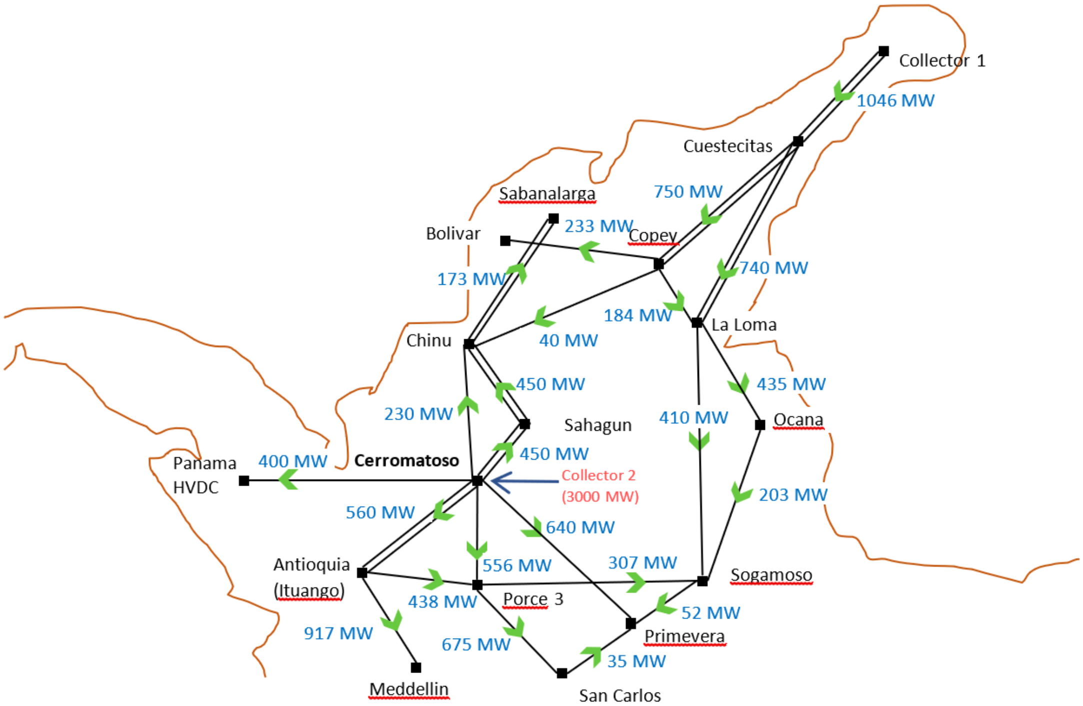


Figure 3-6 Active power flow on selected 500 kV transmission corridors – 2032 Min Dem Min Gen (HVDC connection at Cerromatoso)

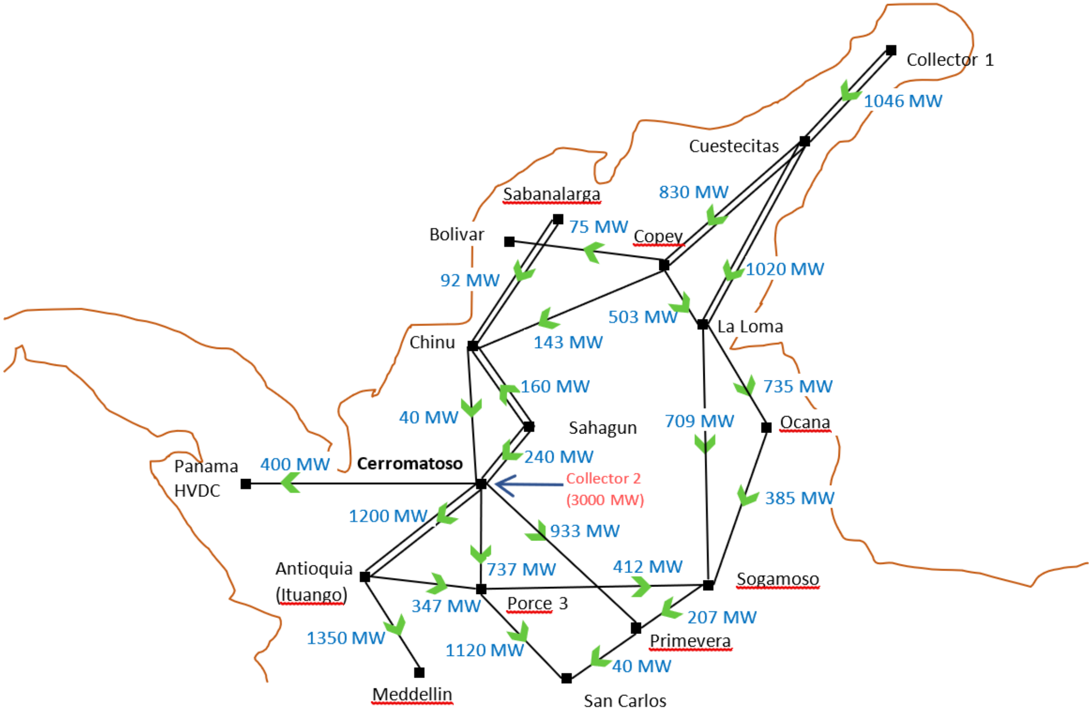


Figure 3-7 Active power flow on selected 500 kV transmission corridors – 2032 Max Dim Max Gen (HVDC connection at Cerromatoso)

3.2.2 Updates to the System Models

Several updates to the DigSILENT database model were made during the study, in agreement with UPME, based on the expected steady state and dynamic performance of the system model.

The changes were made under the following categories:

- Renewable generator model updates

  TGS evaluated the dynamic performance of the generic renewable generator models and recommended a set of parameters to have acceptable responses during the simulations.

- Changes proposed by UPME

  UPME proposed several updates to the system models based on internal performance evaluations.

All the changes were made with the agreement of UPME. The details of the model updates under the above-mentioned categories are provided in Appendix A.

3.2.3 Key Considerations and Assumptions

- Most of the generation in La Guajira is planned to be wind generation. Based on our experience, the wind generators available in the market require a minimum SCR of around 3 for proper operation if they are connected to an AC interconnection. Otherwise, they should be connected to an isolated system with an HVDC in frequency control or an HVDC with grid forming capability. In this case, the latter approach (i.e., HVDC with grid forming capability) was used.
- No existing AC network is present in the La Guajira area where Collector 2 is planned to be located.
- The distance between Collector 1 and Collector 2 is about 50 km.
- The rated HVDC power transfer (i.e. 3000 MW) was assumed to be at the rectifier end (Collector 2).
- The Collector 2 generation was modelled using the same dynamic device models used for the renewable generators in Collector 1.
- Panama HVDC was modeled as a 400 MW load connected to Cerromatoro 500 kV busbar.

3.2.4 VSC HVDC Model Integration

The study cases received from UPME were used as the starting point for the study. The VSC HVDC model was integrated into the study cases along with the renewable generation at Collector 2 and the Collector 1 – Collector 2 500 kV AC interconnection.

Figure 3-8 shows the single line diagram with the VSC HVDC model integrated into the DigSILENT system model.

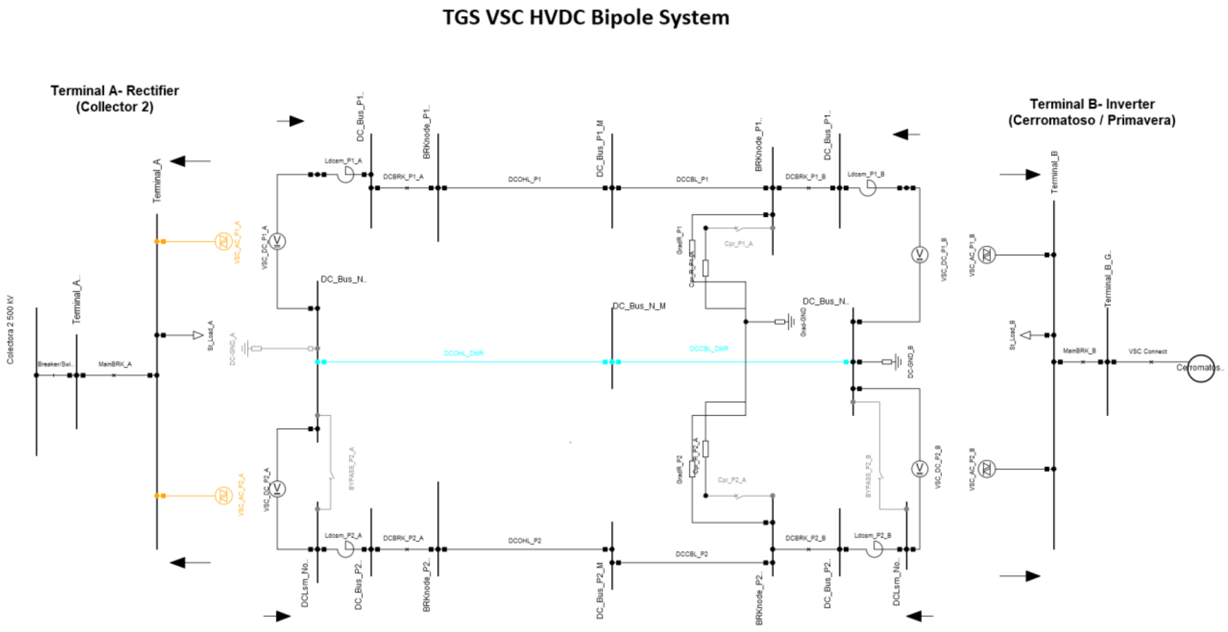
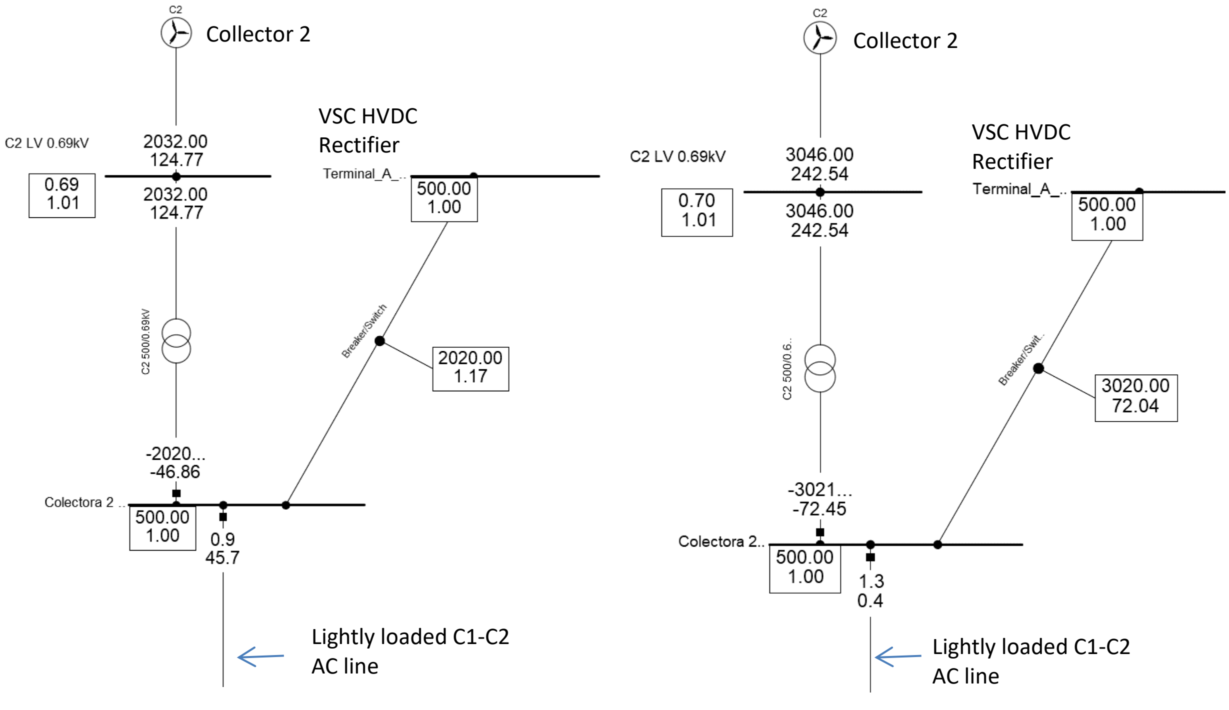


Figure 3-8 VSC HVDC model interconnection in DigSILENT system model

The system intact power flow at Collector 2 for the two operational years are shown in Figure 3-9. The Collector 2 side VSC HVDC transmission in operational year 2028 and 2032 are set to 2000 MW and 3000 MW respectively. The additional 20 MW loads shown at Terminal A and B are included to account for the converter losses and the station load. The Collector 2 generation was set to 2000 MW and 3000 MW for 2028 and 2032 cases respectively. The Collector 1— Collector 2 AC interconnection is lightly loaded under the system intact conditions in both operational years as shown in Figure 3-9. The figure shows the power flow at the VSC HVDC interconnection to Cerromatoso. The power flow is similar for the interconnection at Primavera except for minor differences in reactive power flow.



Operational Year 2028

Operational Year 2032

Figure 3-9 System intact power flow at Collector 2 for the two operational years: 2028 and 2032 (VSC HVDC interconnection—Cerromatoso)

Figure 3-10 and Figure 3-11 show the power flow at the Cerromatoso 500 kV station when the VSC HVDC is interconnected to Cerromatoso in the 2028 and 2032 Max Dem Max Gen study cases.

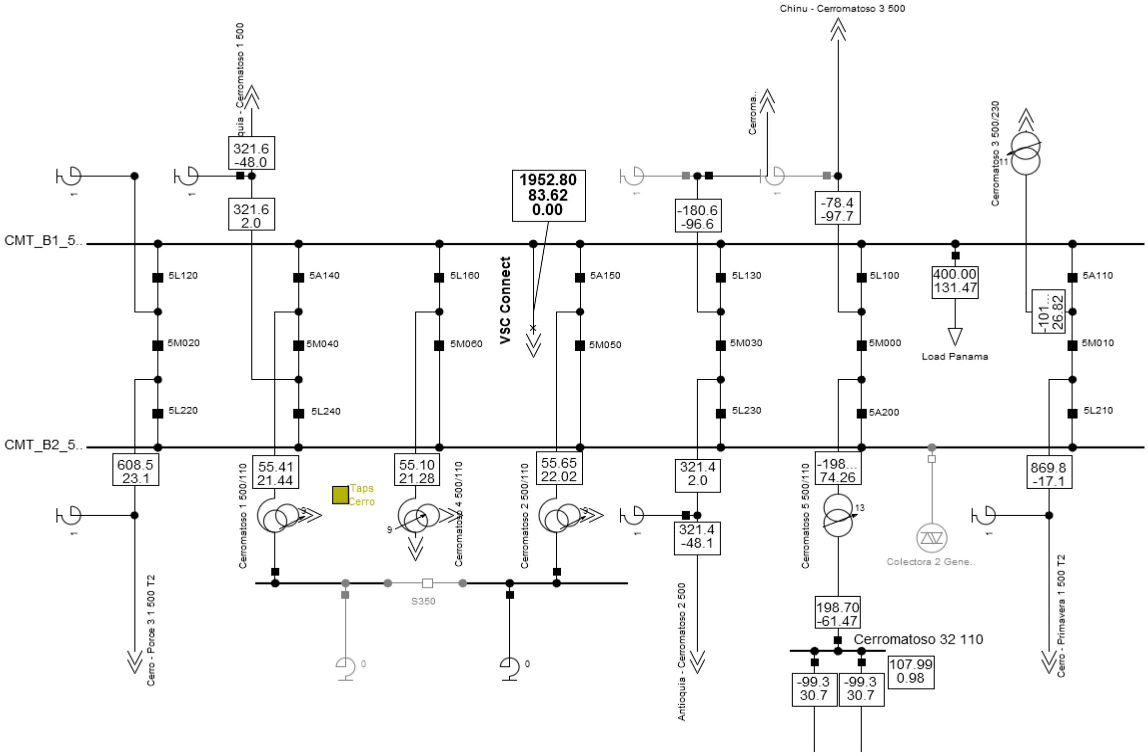


Figure 3-10 System intact power flow at Cerromatoso for 2028 Max Dem Max Gen study case (VSC HVDC interconnection—Cerromatoso)

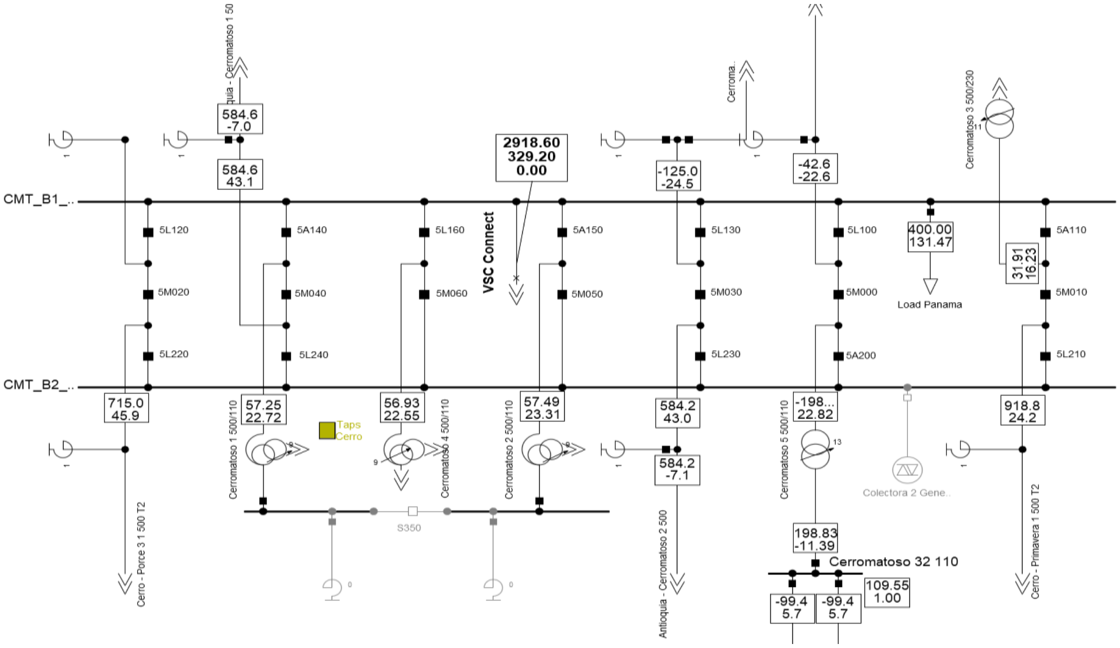


Figure 3-11 System intact power flow at Cerromatoso for 2032 Max Dem Max Gen study case (VSC HVDC interconnection—Cerromatoso)

Figure 3-12 and Figure 3-13 show the power flow at the Primavera 500 kV station when the VSC HVDC is interconnected to Primavera in the 2028 and 2032 Max Dem Max Gen study cases.

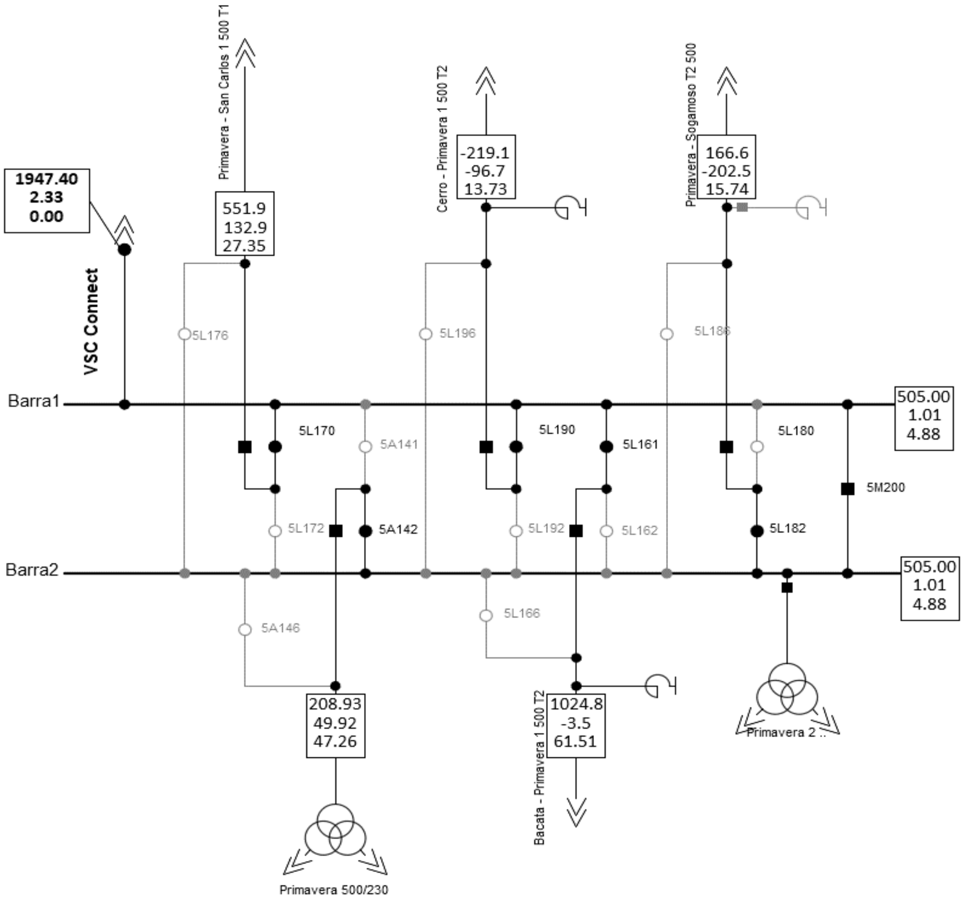


Figure 3-12 System intact power flow at Primavera for 2028 Max Dem Max Gen study case (VSC HVDC interconnection—Primavera)

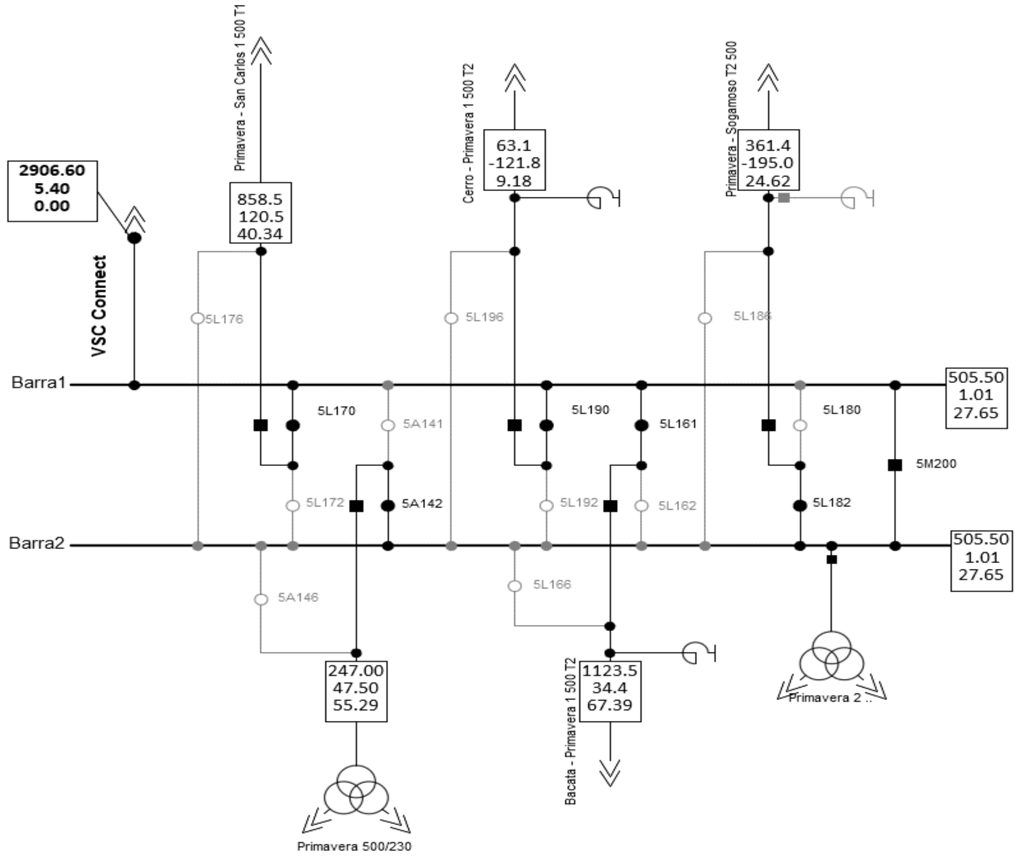


Figure 3-13 System intact power flow at Primavera for 2032 Max Dem Max Gen study case (VSC HVDC interconnection—Primavera)

3.2.5 Study Criteria

During the study the system performance was assessed according to study criteria. The transmission lines, transformers and busbars of nominal voltage level 100 kV and above were monitored during the study.

3.2.5.1 Thermal Loading

Thermal loading of transmission lines and transformers greater than 100% of their rating were monitored and recorded.

3.2.5.2 Steady State Voltages

The steady state voltages were evaluated based on the criteria shown in Table 3-2 as per the Colombian Grid Code.

Table 3-2 Steady state voltage assessment criteria

Busbar nominal voltage (kV)	Min limit (pu)	Max limit (pu)
500	0.9	1.05
100 <= voltage < 500	0.9	1.1

3.2.5.3 Transient Voltage Recovery

The following criteria, specified in the Colombian Grid Code, was used to assess the transient voltage recovery performance:

- Voltage recovers to 0.8 pu within 700 ms after clearing the fault

In addition, TGS included the following criteria to monitor the transient voltage recovery:

- Voltage recovery to normal range within 3 s after clearing the fault
- Voltages do not exceed 1.3 pu for more than 100 ms

3.2.5.4 Frequency Performance

The following criteria, specified in the Colombian Grid Code was used to assess system frequency during the dynamic simulations:

- Nominal operating frequency range between 59.8 Hz and 60.2 Hz
- Frequency should not drop below 57.5 Hz
- Within 10 s of an event, the system frequency should recover to a value higher than the threshold of the first stage of the UFLS (under frequency load shedding) scheme.

3.2.6 List of Contingencies

Table 3-3 shows the list of contingencies provided by UPME for the study. Note that TGS included the contingencies related to the HVDC.

A shortlisted set of severe contingencies, shown in bold text in Table 3-3, was assessed for the transient stability analysis. A half a millisecond (0.0005 s) simulation time step was used for dynamic simulations in DIgSILENT. A 100 ms long three phase to ground bolted fault was applied prior to transmission line outages, reactive power device outages and HVDC terminal faults. The fault was applied at the first station mentioned in the contingency label. For the HVDC pole and bipole outage contingencies, the relevant pole/bipole outage after a DC fault was considered.

Table 3-3 List of Contingencies

Type	Outaged Element	Contingency Label
Transmission line outage	**Chinu - Sabana 2 500 T2**	**Ln 500 Chinu-Sabana**
	Antioquia - Cerromatoso 1 500	**Ln 500 Cerromatoso-Antioquia 1**
	Antioquia - Medellin 1 500	**Ln 500 Antioquia-Medellin 1**
	Antioquia - Porce III 1 500	**Ln 500 Antioquia-Porce III 1**
	Bacata - Nva Esperanza 1 500	**Ln 500 Bacata-Nva Esperanza 1**
	Bacata - Primavera 1 500 T2	**Ln 500 Primavera-Bacata 1**
	Bolivar - Copey 1 500 T2	**Ln 500 Bolivar-Copey 1**
	Bolivar - Sabana 1 500	**Ln 500 Bolivar-Sabana 1**
	Carreto - Chinu 1 500	Ln 500 Carreto-Chinu 1
	Carreto - Sabana 1 500	Ln 500 Carreto-Sabana 1
	Chinu - Cerromatoso 3 500	**Ln 500 Cerromatoso-Chinu- 3**
	Cerro - Porce 3 1 500 T2	**Ln 500 Cerromatoso-Porce 3**
	Cerro - Primavera 1 500 T2	**Ln 500 Cerro-Primavera 1**
	Cerro - Sahagun 1 500	**Ln 500 Cerro-Sahagun 1**
	Chinu - Sabana 2 500 T2	Ln 500 Chinu-Sabana 1
	China - Sahagun 1 500	**Ln 500 Chinu-Sahagun 1**
	Copey - Cuestecitas 1 500 T2	**Ln 500 Copey-Cuestecitas 1 T2**
	Copey - La Loma 1 500 T2	**Ln 500 Copey-La Loma 1 T2**
	Cuestecitas - Colectora1 1 500 T2	**Ln 500 C1-uestecitas T2**
	Cuestecitas - La Loma 1 500 T2	**Ln 500 Cuestecitas-La Loma 1 T2**
	Guayepo - Sabana 1 500	Ln 500 Guayepo-Sabana 1
	La Loma - Ocaña 1 500 T1	**Ln 500 La Loma-Ocana 1 T1**
	La Loma - Sogamoso 1 500 T2	**Ln 500 La Loma-Sogamoso 1 T2**
	Medellin - Virginia 1 500	Ln 500 Medellin-Virginia 1
	Norte - Nueva Esperanza 1 500	Ln 500 Norte-Nueva Esperanza 1
	Norte - Sogamoso 1 500 T2	Ln 500 Norte-Sogamoso 1 T2
	Ocaña - Sogamoso T2 500	Ln 500 Ocana-Sogamoso T2
	Porce III - San Carlos 1 500 T2	**Ln 500 Porce III-San Carlos 1 T2**
	Porce III - Sogamoso 1 500	**Ln 500 Porce III-Sogamoso 1**

Type	Outaged Element	Contingency Label
	Primavera - San Carlos 1 500 T1	**Ln 500 Primavera-San Carlos 1 T1**
	Primavera - Sogamoso T2 500	**Ln 500 Primavera-Sogamoso T2**
	Sabanalarga - Tebsa 2 220	Ln 220 Sabanalarga-Tebsa 2
	Sabanalarga - Tebsa 3 220	Ln 220 Sabanalarga-Tebsa 3
	Caracoli - Sabanalarga 1 220	Ln 220 Caracoli-Sabanalarga 1
	Flores - Nv Barranquilla 1 220	Ln 220 Flores-Nv Barranquilla 1
	El Rio - Tebsa 1 220	Ln 220 El Rio-Tebsa 1
	Caracoli - Tebsa 1 220	Ln 220 Caracoli-Tebsa 1
	El Rio - Tebsa 1 220	Ln 220 El Rio-Tebsa 1
	Guajira - Termocol 220 kV (Smart Valve)	**Ln 220 Guajira-Termocol Smart Valve**
	Guajira - Santa Marta 220 (Smart Valve)	**Ln 220 Guajira-SMarta-Smart Vlv**
	Chinu - Copey 1 500	**Ln 500 Chinu-Copey 1**
	Santa Marta - Termocol 1 220	**Ln 220 Santa Marta-Termocol 1**
	Cuestecitas(TRC) - San Juan 1 220	**Ln 220 Cuestecitas(TRC)-SJuan 1**
	Alferez - San Marcos 1 500	Ln 500 Alferez-San Marcos 1
	Alferez - Virginia 1 500	Ln 500 Alferez-Virginia 1
	Antioquia - Cerromatoso 2 500	**Ln 500 Cerromatoso-Antioquia 2**
	Copey - Cuestecitas 2 500 T2	**Ln 500 Copey-Cuestecitas 2 T2**
	Nueva Esperanza - Virginia1 1 500 T2	**Ln 500 NEsperanza-Virginia1 1 T2**
	San Carlos - Virginia 1 500 T2	**Ln 500 S Carlos-Virginia 1 T2**
	San Marcos - Virginia 1 500 T1	**Ln 500 S Marcos-Virginia 1 T1**
Transformer outage	**Trafo 500/11 SVC**	**Tf2 Trafo 500-11 SVC**
	Bolivar 500/230	**Tf3 Bolivar 500-230**
	Carreto 1 500/66	Tf3 Carreto 1 500-66
	Cerromatoso 1 500/110	Tf3 Cerromatoso 1 500-110
	Cerromatoso 2 500/110	Tf3 Cerromatoso 2 500-110
	Cerromatoso 4 500/110	Tf3 Cerromatoso 4 500-110
	Chinu 2 500/110	Tf3 Chinu 2 500-110
	Chinu 3 500/110	Tf3 Chinu 3 500-110

Type	Outaged Element	Contingency Label
	Chinu 4 500/230	**Tf3 Chinu 4 500-230**
	Copey 1 500/220	**Tf3 Copey 1 500-220**
	Cuestecitas 500/230	**Tf3 Cuestecitas 500-230**
	La Loma 1 500/110	**Tf3 La Loma 1 500-110**
	Sabana 2 500/220	**Tf3 Sabana 2 500-220**
	Flores 10 220/110	Tf3 Flores 10 220-110 kV
	NMonteria 1 230/110	Tf3 NMonteria 1 230-110
	Cerromatoso 3 500/230	**Tf2 Cerromatoso 3 500-230**
	Ocaña 1 500/230	**Tf3 Ocana 1 500-230 kV**
	San Carlos 2 500/230	**Tf3 San Carlos 2 500-230**
	Primavera 500/230	**Tf3 Primavera 500-230**
	Medellin 1 500/230	**Tf3 Medellin 1 500-230**
Largest synchronous generator outage	**2032 Max - Gecelca 32 (200 MW)**	**LargestGen**
	2032 Min - Ituango 1 (200 MW)	
	2028 Max - Ituango 1 (300 MW)	
	2028 Min - Gecelca 32 (200 MW)	
Reactive power supply device outages	Trafo 500/11 SVC	SVC Chinu ISA 250Mvar
	SVC OXY 34.5 kV	SVC Oxy 84Mvar
	Trafo 230/19.8 SVC Tunal	**SVC Tunal 100Mvar**
	Trf STATCOM Bacata 500/28	**STATCOM Bacata 200Mvar**
C1-C2 AC line	**Colectora 1 - Colectora 2 500 kV**	**Ln 500 C1-C2**
VSC HVDC-Three phase fault, clearing and recovery at Collector 2 AC bus (rectifier fault)	_	**Term_A_3PSF**
VSC HVDC-Three phase fault, clearing and recovery at Cerromatoso or Primavera 500 kV AC bus (inverter fault)	_	**Term_B_3PSF**
VSC HVDC-Permeant DC pole-to-ground fault (pole outage)	**Single pole of VSC HVDC**	**Pole Outage**

Type	Outaged Element	Contingency Label
VSC HVDC Bipole outage	**Both poles of VSC HVDC**	**Bipole Outage**

3.3 Steady State Analysis

The steady state analysis was performed to determine any adverse impacts of the VSC HVDC interconnection on the Colombian power system.

3.3.1 Methodology

The steady state contingency analysis was performed using DigSILENT Power Factory 2020. In the study, the post contingency operating points with the Collector 2 renewable generation integrated using the VSC HVDC were assessed for grid code compliance. The thermal and voltage criteria used for the performance assessment is shown in Section 3.2.5.

The generators at Chivor, San Carlos, Betania and Quimbo were set to compensate the active power flow mismatch in the post contingency operating conditions (active power control according to the Secondary Control).

A set of feasible network upgrades were proposed to mitigate the grid code violations identified during the study.

The study was repeated for both proposed VSC HVDC interconnection locations: Cerromatoso and Primavera.

3.3.2 Study Results—Interconnection at Cerromatoso

The results of the steady state analysis are presented under the following sections:

- System intact
- N-1 contingencies
- VSC HVDC bipole outage

3.3.2.1 System intact

3.3.2.1.1 Equipment overloads

Table 3-4 shows the equipment overload observed and the proposed network upgrades under the system intact conditions.

Table 3-4 System intact equipment overloads –VSC HVDC interconnection at Cerromatoso

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
Transmission Lines					
Nueva Esperanza - Río 115 kV	102%	-	108%	-	Proposed upgrades: • This is a short transmission line (7 km). Reconductoring or adding a new circuit can be done. • Redispatch to avoid overloads during the contingency Note that no significant increase in the overloading of this line was observed under the contingencies. Therefore, this transmission line will not be repeated under the list of N-1 violations.

3.3.2.1.2 Busbar voltage limit violations

Table 3-5 shows the voltage limit violation observed and the proposed network upgrades under the system intact conditions.

Table 3-5 System intact busbar voltage limit violations –VSC HVDC interconnection at Cerromatoso

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
Tumaco 115	-	-	0.86	-	Proposed upgrades: The voltage violation can be fixed by installing a shunt capacitor. This bus is far away from the proposed VSC HVDC and close to the Ecuador boarder. Note that no significant voltage decrease in this busbar was observed under the contingencies. Therefore, this busbar will not be repeated under the list of N-1 violations.

3.3.2.2 N-1 contingencies

Following contingencies, in Table 3-3, were considered under N-1:

- Transmission line outages
- Transformer outages

- Largest synchronous generator outages
- Reactive power supply device outages
- Collector 1— Collector 2 500 kV AC line
- VSC HVDC pole outage

Note that in 2028 study cases, the system intact power transmission in each VSC HVDC pole is 1000 MW. For the pole outage the power transmission in the healthy pole is increased to 1500 MW. In 2032 cases, each pole is already loaded to 1500 MW, therefore, the remaining pole will stay at 1500 MW.

The detailed simulation results of the steady state contingency analysis are included in Appendix B. The worst-case equipment overloads and busbar voltage limit violations are discussed below.

3.3.2.2.1 Equipment overloads

Table 3-6 shows the equipment overloads and the proposed network upgrades under the N-1 contingencies.

Table 3-6 equipment overloads under N-1 contingencies–VSC HVDC interconnection at Cerromatoso

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
Transmission lines					
Porce III - San Carlos 1 500	111%	-	109%	-	The maximum overloads were observed under the outage of Antioquia—Medellin 500 kV transmission line. In 2028-Max study case, Antioquia—Medellin 500 kV line transmits about 1380 MW to Medellin. From Medellin, about 860 MW is then transmitted to Virginia. For the outage of the line, some of the power from Antioquia to Virginia is transmitted through Porce and San Carlos. This results in an overload in the Porce—San Carlos 500 kV transmission line. UPME confirmed that it is necessary to prevent this overload as it is beyond the emergency limit of the transformer. Proposed upgrades (select one): • Additional circuit to Antioquia—Medellin 500 kV transmission line

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
					• Additional circuit to Porce III - San Carlos 500 kV transmission line. • Redispatch to avoid overloads during the contingency
Ancon Sur - Medellin 1 220	105%	-	104%	-	The maximum overloads were observed under the outage of Medellin—Virginia 500 kV transmission line. This overload is acceptable to UPME as it does not violate the emergency limit of the transmission line.
Transformers					
Norte 500/230	115%	-	120%		The maximum overloads were observed under the outage of Norte - ReaNva Espe 1 500 kV transmission line. In 2032 Max study case, under the outage of Norte—Nva Esperanza 500 kV transmission line, the transformer is loaded about 250 MW more than in the system intact condition. This overload is acceptable to UPME as it does not violate the emergency limit of the transformer.
Chinu 1 500/110 Chinu 2 500/110 Chinu 3 500/110	108%	-	115%	-	The maximum overloads were observed under the outage of any of the parallel transformers. These 3 transformers rated at 150 MVA are loaded over 80% in the system intact condition. Therefore, the outage of one transformer overloads the other two. Only Chinu 3 500/110 can be loaded up to 115% under N-1 conditions. The other two parallel transformers can be loaded only up to 110 %. Proposed upgrade: Include an additional transformer in parallel
Medellin 1 500/230 Medellin 2 500/230	-	-	101%	-	The maximum overloads were observed under the outage of Medellin—Virginia 500 kV transmission line.

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
					This overload is acceptable to UPME as it does not violate the emergency limit of the transformer.
Cuestecitas 500/230	-	-	-	109%	The maximum overload was observed under the single pole outage of the VSC HVDC. For the pole outage, the AC transmission line from Collector 1 to Collector 2 transmits about 1500 MW to Collector 1. Under these conditions, the power transmission to the 220 kV network in the Cuestecitas 500/230 transformer is increased and resulted in about 109% loading. This overload is acceptable to UPME as it does not violate the emergency limit of the transformer.
La Virginia 500/230	107%	-	105%	-	The maximum overload was observed under the outage of S Marcos-Virginia 500 kV transmission line. In 2028 Max study case, the 450 MVA transformer is loaded over 80% in the system intact condition. Under the outage of S Marcos-Virginia 500 kV transmission line, the power transmission to the 220 kV network in the La Virginia 500/230 transformer is increased and resulted in about 107% loading. UPME confirmed that it is necessary to prevent this overload as it is beyond the emergency limit of the transformer. Proposed upgrades: • Include additional transformer in parallel • Redispatch to avoid overloads during the contingency

3.3.2.2.2 Busbar voltage limit violations

Table 3-7 shows the busbar voltage limit violations and the proposed network upgrades under the N-1 contingencies. UPME confirmed that it is necessary to prevent the bus bar voltage limit violations. The proposed solutions are listed in the table.

Table 3-7 Busbar voltage limit violations under N-1 contingencies–VSC HVDC interconnection at Cerromatoso

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
High voltages (pu)					
Santa Rosalia 115 Banadia 220 C Limon 220 La Paz 220	1.11	-	-	1.11	Several minor voltage violations were observed under the outage of SVS Oxy 84 Mvar in Nordeste. In 2032 Min study case, the 84 Mvar SVS is absorbing about 51 Mvar in the system intact condition. Therefore, the outage of the SVS result in overvoltage in nearby busbars. Proposed upgrades: A fixed shunt (reactor) can be installed to adjust the system intact operating point of the SVS to reduce the reactive power absorption under the system intact conditions. This will also be benefited during transients as the SVS will be able to support in a wider range.
Low Voltages (pu)					
Junin 115	-	-	0.88	-	The low voltage limit violations were observed under the outage of S Marcos-Virginia 500 kV transmission line. This is a minor violation and Junin busbar is very far from VSC HVDC (close to Ecuador boarder). Therefore, a solution was not proposed.

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
El Banco 110 La Jagua 110 Riohacha 110 Maicao 110	-	-	0.83	0.88	Several low voltage limit violations were observed under the VSC HVDC pole outage. Under the pole outage, the 500 kV AC transmission lines transmit more power to South than under system intact conditions. This results in relatively low voltages along the transmission corridor. Shunt reactors are in-service in almost all 500 kV transmission lines along the corridor. The transient stability analysis showed the need to cross trip the 500 kV line reactors and other measures to enable an acceptable system recovery at the VSC HVDC pole outage. This is further discussed, and the solutions are proposed in Section 3.4.

3.3.2.3 VSC HVDC bipole outage

During the bipole outage, it is not possible to transmit the entire generation of Collector 2 to the AC network. Therefore, it is necessary to shed a portion of the generation in Collector 2. The generation shed results in the system frequency to drop and the UFLS to shed loads to maintain the system frequency within acceptable limits. Since this is an N-2 outage, generation and load shedding is acceptable. The amount of generation shed, and load shedding depend on the dynamic behaviour and therefore, the bipole outage and required generation shed are discussed in detail in transient stability (Section 3.4).

3.3.3 Study Results—Interconnection at Primavera

The results of the steady state analysis are presented under the following sections:

- System intact
- N-1 contingencies
- VSC HVDC bipole outage

3.3.3.1 System intact

3.3.3.1.1 Equipment overloads

Table 3-8 shows the equipment overload and the proposed network upgrades under the system intact conditions. Note that this overload is same as the one observed for option with HVDC terminal at Cerromatoso.

Table 3-8 System intact equipment overloads –VSC HVDC interconnection at Primavera

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
Transmission Lines					
Nueva Esperanza - Río 115 kV	102%	-	108%	-	Proposed upgrades: • This is a short transmission line (7 km). Reconductoring or adding a new circuit can be done. • Redispatch to avoid overloads at the contingency Note that no significant increase in the overloading of this line was observed under the contingencies. Therefore, this transmission line is not repeated under the list of N-1 violations.

3.3.3.1.2 Busbar voltage limit violations

Table 3-9 shows the voltage limit violation observed and the proposed network upgrades under the system intact conditions.

Table 3-9 System intact busbar voltage limit violations –VSC HVDC interconnection at Primavera

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
Tumaco 115	0.88	-	0.87	-	Proposed upgrades: The voltage violation can be fixed by installing a shunt capacitor. This bus is far away from the proposed VSC HVDC and close to the Ecuador boarder. Note that no significant voltage decrease in this busbar was observed under the contingencies. Therefore, this busbar will not be repeated under the list of N-1 violations.

3.3.3.2 N-1 contingencies

Following contingencies, in Table 3-3, were considered under N-1:

- Transformer outages
- Largest synchronous generator outages
- Reactive power supply device outages
- Collector 1— Collector 2 500 kV AC line
- VSC HVDC pole outage

The detailed simulation results of the steady state contingency analysis are included in Appendix B. The worst-case equipment overloads and busbar voltage limit violations are discussed below.

3.3.3.2.1 Equipment overloads

Table 3-10 shows the equipment overloads and the proposed network upgrades under the N-1 contingencies.

Table 3-10 equipment overloads under N-1 contingencies–VSC HVDC interconnection at Primavera

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
Transmission lines					
Bacata - Suba 1 115	-	-	104%	-	The maximum overload was observed under the outage of Bacata-Nva Esperanza 1 500 kV transmission line. This transmission line can be loaded up to 120% under N-1 conditions. Therefore, this overload is acceptable.
Transformers					
Norte 500/230	111%	-	112%		The maximum overloads were observed under the outage of Norte - ReaNva Espe 1 500 kV transmission line. In 2032 Max study case, under the outage of Norte—Nva Esperanza 500 kV transmission line, the transformer is loaded about 250 MW more than in the system intact condition. This transformer can be loaded up to 120% under N-1 conditions.

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
					Therefore, this overload is acceptable.
Chinu 1 500/110 Chinu 2 500/110 Chinu 3 500/110	107%	-	114%	-	The maximum overloads were observed under the outage of any of the parallel transformers. These 3 transformers rated at 150 MVA are loaded over 80% in the system intact condition. Therefore, the outage of one transformer overloads the other two. Only Chinu 3 500/110 can be loaded up to 115% under N-1 conditions. The other two parallel transformers can be loaded only up to 110 %. Proposed upgrade: Include an additional transformer in parallel
Cuestecitas 500/230	-	-	-	111%	The maximum overload was observed under the single pole outage of the VSC HVDC. At the pole outage, the AC transmission line from Collector 1 to Collector 2 transmits about 1500 MW to Collector 1. Under these conditions, the power transmission to the 220 kV network in the Cuestecitas 500/230 transformer is increased and resulted in about 111% loading. This transformer can be loaded up to 130% under N-1 conditions. Therefore, this overload is acceptable.
La Virginia 500/230	103%	-	-	-	The maximum overload was observed under the outage of S Marcos-Virginia 500 kV transmission line. In 2028 Max study case, the 450 MVA transformer is loaded over 80% in the system intact condition. Under the outage of S Marcos-Virginia 500 kV transmission line, the power transmission to the 220 kV network in the La Virginia 500/230 transformer is increased and resulted in about 103% loading.

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
					This transformer can be loaded up to 105% under N-1 conditions. Therefore, this overload is acceptable.

3.3.3.2.2 Busbar voltage limit violations

Table 3-11 show the busbar voltage limit violations observed and the proposed network upgrades under the N-1 contingencies. UPME confirmed that it is necessary to avoid the bus bar voltage limit violations. The solutions are listed in the table.

Table 3-11 Busbar voltage limit violations under N-1 contingencies–VSC HVDC interconnection at Primavera

Monitored Element	2028 Max Dem Max Gen	2028 Min Dem Min Gen	2032 Max Dem Max Gen	2032 Min Dem Min Gen	Comments
High voltages (pu)					
Santa Rosalia 115 San Luis 115 Banadia 220 C Limon 220 La Paz 220	1.12	-	1.1	1.13	Several minor voltage violations were observed under the outage of SVS Oxy 84 Mvar in Nordeste. In 2032 Min study case, the 84 Mvar SVS is absorbing about 55 Mvar in the system intact condition. Therefore, the outage of the SVS result in overvoltage in nearby busbars. Proposed upgrades: • A fixed shunt (reactor) can be installed to adjust the system intact operating point of the SVS to reduce the reactive power absorption under the system intact conditions. This will also be benefited during transients as the SVS is able to support in a wider range.
Low Voltages (pu)					
El Banco 110 La Jagua 110 Riohacha 110 Maicao 110	-	-	0.85	0.88	Several low voltage limit violations were observed under a VSC HVDC pole outage. Under the pole outage, the 500 kV AC transmission lines transmit more power to South than under system intact conditions. This results in relatively low voltages along the transmission corridor. Shunt reactors are in-service in almost all 500 kV transmission lines along the corridor. The transient stability analysis showed that it is necessary to cross trip the 500 kV line reactors and other measures to enable an acceptable system recovery at the VSC HVDC pole outage. This is further discussed in Section 3.4.

3.3.3.3 VSC HVDC bipole outage

During the bipole outage, it is not possible to transmit the entire generation of Collector 2 to the AC network. Therefore, it is necessary to shed a portion of the generation in Collector 2. The generation shed results in the system frequency to drop and the UFLS to shed loads to maintain the system frequency within acceptable limits. Since this is an N-2 outage, generation and load shedding is acceptable. The amount of generation shedding, and load shedding depend on the dynamic behaviour and therefore, the bipole outage and required generation shed are discussed in detail in transient stability analysis (Section 3.4).

3.3.4 Comparison of Network Upgrade Requirements

This section compares the AC network upgrades required for the two HVDC interconnection locations. A comparison is shown in Table 3-12. The Primavera option requires less system upgrades. Therefore, the Primavera option is a better location in terms of system upgrades required for the steady state power transfer.

Table 3-12 Required network upgrades based on steady state analysis for proposed VSC HVDC interconnection locations

Equipment Overflow	VSC HVDC interconnection location	
	Cerromatoso	Primavera
Transmission lines		
Nueva Esperanza - Río 115 kV	Upgrade required	Upgrade required
Porce III - San Carlos 1 500	Upgrade required	-
Bacata - Suba 1 115	-	Upgrade required
Transformers		
Chinu 1 500/110 Chinu 2 500/110 Chinu 3 500/110	Upgrade required	Upgrade required
La Virginia 500/230	Upgrade required	-

The busbar voltage limit violations are common for both of the options. Therefore, the required upgrades are the same.

3.4 Transient Stability Analysis

The transient stability of the system with the VSC HVDC was assessed for a set of critical contingencies. The transient system performance was assessed against the defined performance criteria. As required, additional measures were introduced to ensure the system remains in synchronism and meets the performance criteria. The methodology and the results are summarized in this section.

3.4.1 Methodology

In this study, the transient stability of the system with the VSC HVDC was assessed for the set of contingencies defined in Section 3.2.6. The system is considered stable if it can remain in synchronism after being subjected to the disturbance (contingency). In addition, during the transition from the pre-contingency to post-contingency operating point, the system responses are checked against the transient voltage and frequency criteria according to the Colombian grid code and several additional performance criteria proposed by TGS (as described in Section 3.2.5).

The following were investigated:

- The system dynamic response and recovery for simple and extreme AC and DC contingencies
- The performance of the Under-Frequency Load Shedding (UFLS) scheme
- The need for additional reactive power resources and dynamic compensation
- The need for additional network reinforcements (in addition to steady state requirements)

A shortlisted set of severe contingencies, shown in bold text in Table 3-3, was assessed for the transient stability. A half a millisecond (0.0005 s) simulation time step was used for dynamic simulations. A 100 ms long three phase to ground bolted fault was applied prior to transmission line outages, reactive power device outages and HVDC terminal faults. The fault was applied at the first station mentioned in the contingency label in Table 3-3. A DC fault was applied in the HVDC pole and bipole outage contingencies. Each contingency was simulated for 20 s except for the largest synchronous generator outage. The generator outages were simulated for 60 s to capture the governor responses of the generators.

The study was repeated for both proposed VSC HVDC interconnection locations: Cerromatoso and Primavera.

3.4.2 Study Results—Interconnection at Cerromatoso

The results of the transient stability analysis are presented under the following sections:

- N-1 contingencies
- Contingencies Related to HVDC

3.4.2.1 N-1 Contingencies

The N-1 contingencies listed in Table 3-3 were simulated. These contingencies include:

- Transmission line outages
- Transformer outages
- Reactive power supply device outages
- Collector 1— Collector 2 500 kV AC line outage
- Largest synchronous generator outage

Table 3-13 lists the relevant generators tripped under the largest synchronous generator outage in each study case.

Table 3-13 Largest synchronous generator tripped in each study case

Operational Year	Study Case	The synchronous generator tripped in the largest synchronous generator outage contingency	Generator dispatch (MW)
2028	Min Dem Min Gen	Gecela 32	200
	Max Dem Max Gen	Ituango 1	300
2032	Min Dem Min Gen	Ituango 1	200
	Max Dem Max Gen	Gecela 32	200

The transient stability analysis showed that the system performance is acceptable under all the N-1 contingencies:

- Transient voltage recovery criteria were satisfied (defined in Section 3.2.5).
- Transient frequency criteria were satisfied (defined in Section 3.2.5).
- No loads were shed.
- Performance of the VSC HVDC was acceptable.
- All generators remained in synchronism.

The detailed dynamic simulation results for all the study cases are given in Appendix C. A summary of the results is discussed in the following sections.

Two sets of plots are provided for every contingency to show the transient response of the VSC HVDC and the AC system. In the VSC HVDC related plots, the station A is the rectifier side, and the station B is the inverter side. The channels names in the plots are named accordingly. For example, the channel name *VSC_AC_P1_A-v bus 1 pu* denotes the per unit voltage of the pole 1 AC busbar at the rectifier side of the VSC HVDC.

3.4.2.1.1 Transmission Line Outage

The dynamic performance for all the transmission line outages (N-1) is acceptable. As an example, the simulation results for the outage of the 500 kV transmission line from Cerromatoso to Primavera in the 2032—Max Dem Max Gen study case are shown in Figure 3-14 and Figure 3-15. The first figure shows the HVDC performance, and the second figure shows AC system performance.

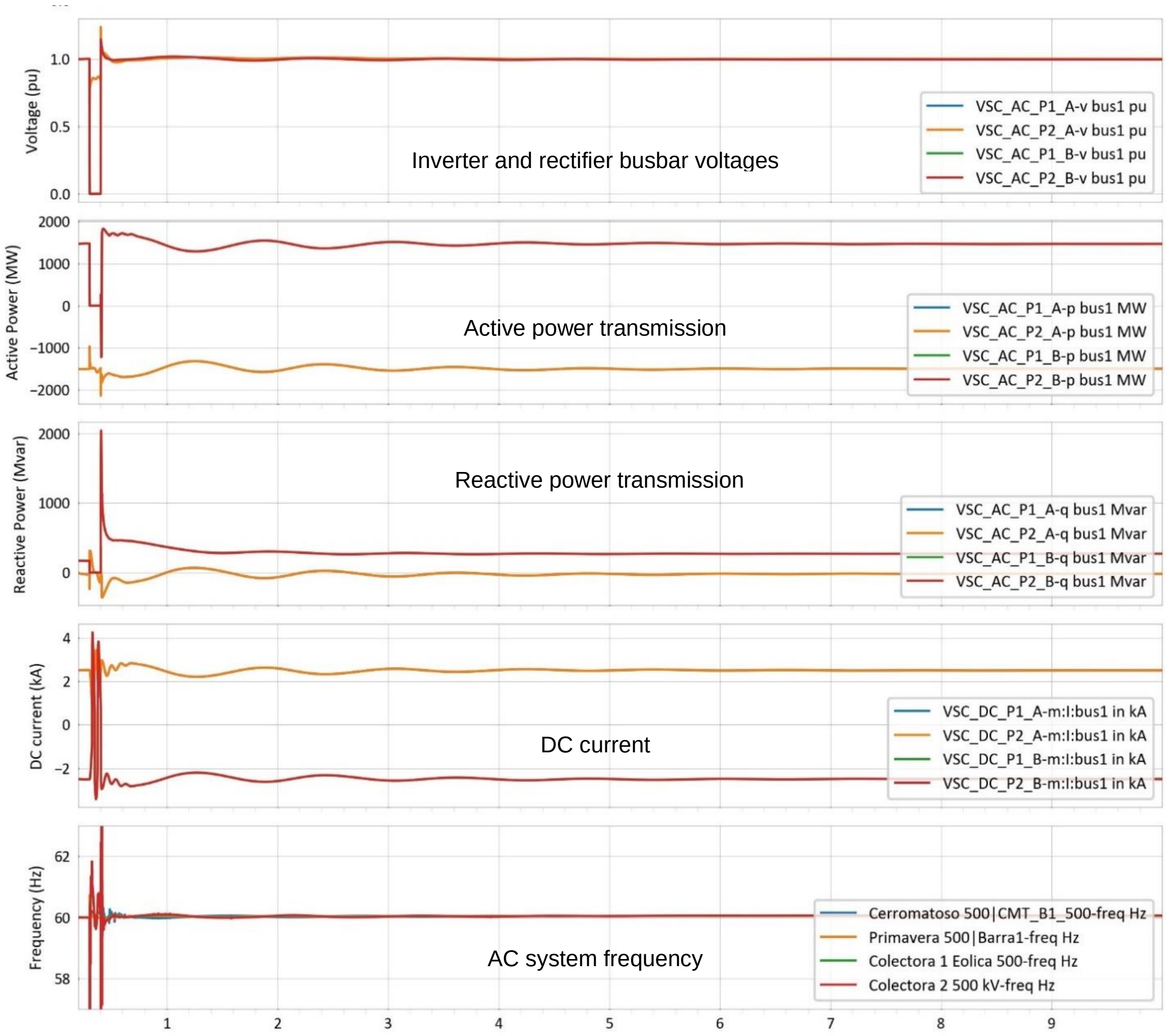


Figure 3-14 VSC HVDC response (Contingency: 500 kV Cerromatoso—Primavera transmission line outage, Contingency label: Ln 500 Cerro-Primavera 1, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

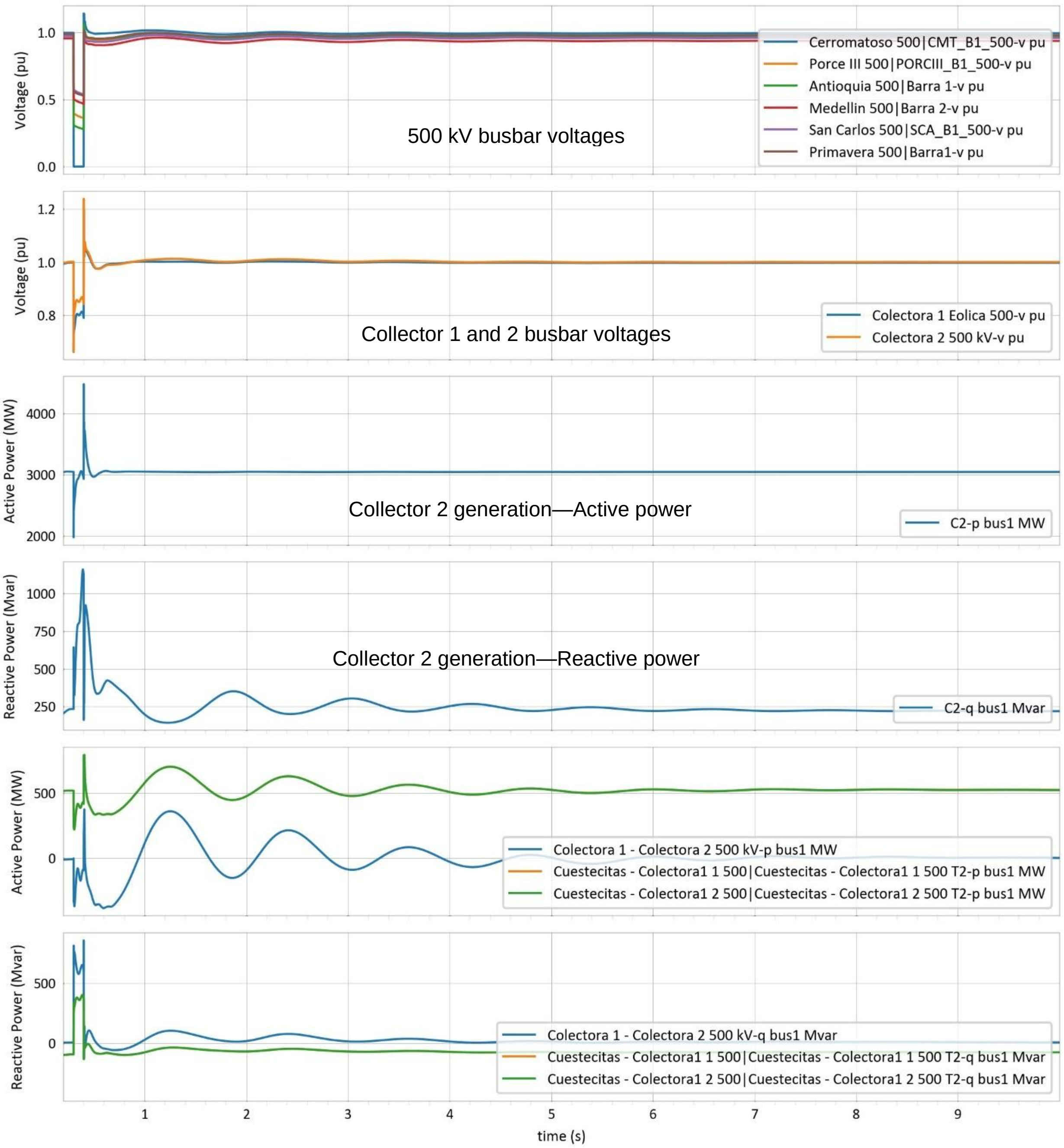


Figure 3-15 AC system response (Contingency: 500 kV Cerromatoso—Primavera transmission line outage, Contingency label: Ln 500 Cerro-Primavera 1, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

The 500 kV transmission line from Cerromatoso to Primavera transmits about 900 MW in the 2032 Max Dem Max Gen study case. In this contingency, the fault was applied at the 500 kV Cerromatoso busbar. Therefore, during the fault, the voltage at the inverter busbar drops to zero. This results in no power transmission at the inverter. As a result, the DC chopper activates and the HVDC power at the rectifier terminal was kept close to the pre-fault value. The post contingency system recovery complies with the grid code. The post contingency reactive power at the inverter settles to a higher value due to the line outage.

The recovery of the AC system meets the system performance criteria.

Note that the spikes shown at the moment of fault inception and fault clearing are a result of the algebraic network (admittance matrix) solution used in the RMS simulations. These spikes are ignored in the transient stability simulations and need to be evaluated using EMT simulations.

3.4.2.1.2 Transformer Outage

For all transformer outages, the system dynamic performance is well within the system performance criteria. All the dynamic results are given in Appendix C.

3.4.2.1.3 Largest Synchronous Generator Outage

The simulation results for the largest synchronous generator (Ituango 1) outage, in the 2028-Max Dem Max Gen study case are shown in Figure 3-16 through Figure 3-18. The outage of this generator results in the largest power mismatch of 300 MW.

Figure 3-16 shows the dynamic response of the VSC HVDC bipole. Figure 3-17 shows the dynamic response of the AC system and Figure 3-18 shows the response of response of some selected synchronous generators. As a result of the generator outage, the system frequency drops 59.7 Hz. The governors responded quickly to limit the frequency drop. Figure 3-18 shows the increase of active power output on Chivor and San Carlos generators as a response to the frequency drop. The HVDC transfer stays intact. The dynamic performance of the system meets the system performance criteria.

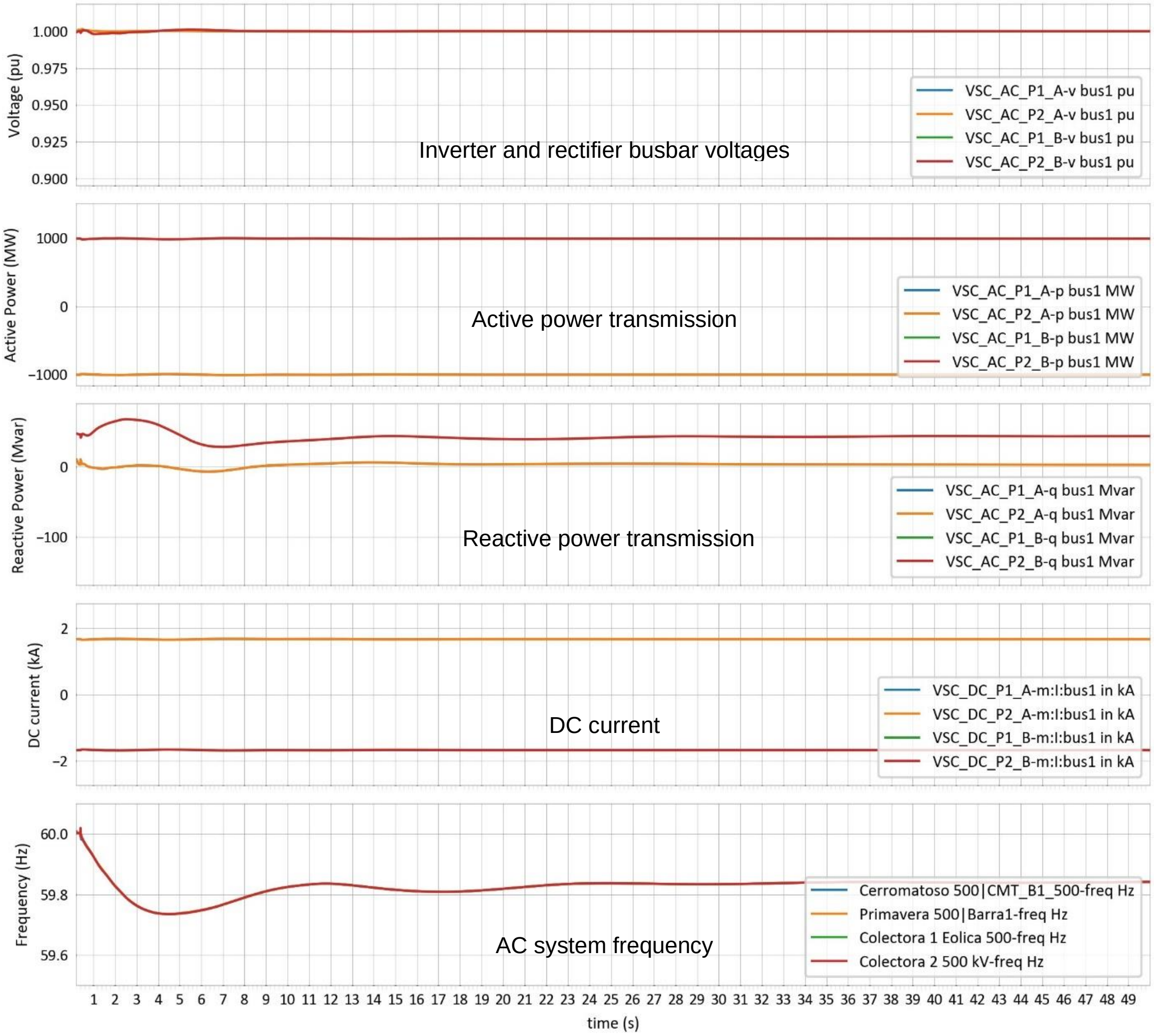


Figure 3-16 VSC HVDC response (Contingency: largest synchronous generator outage—300 MW Ituango 1, Study case: 2028 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

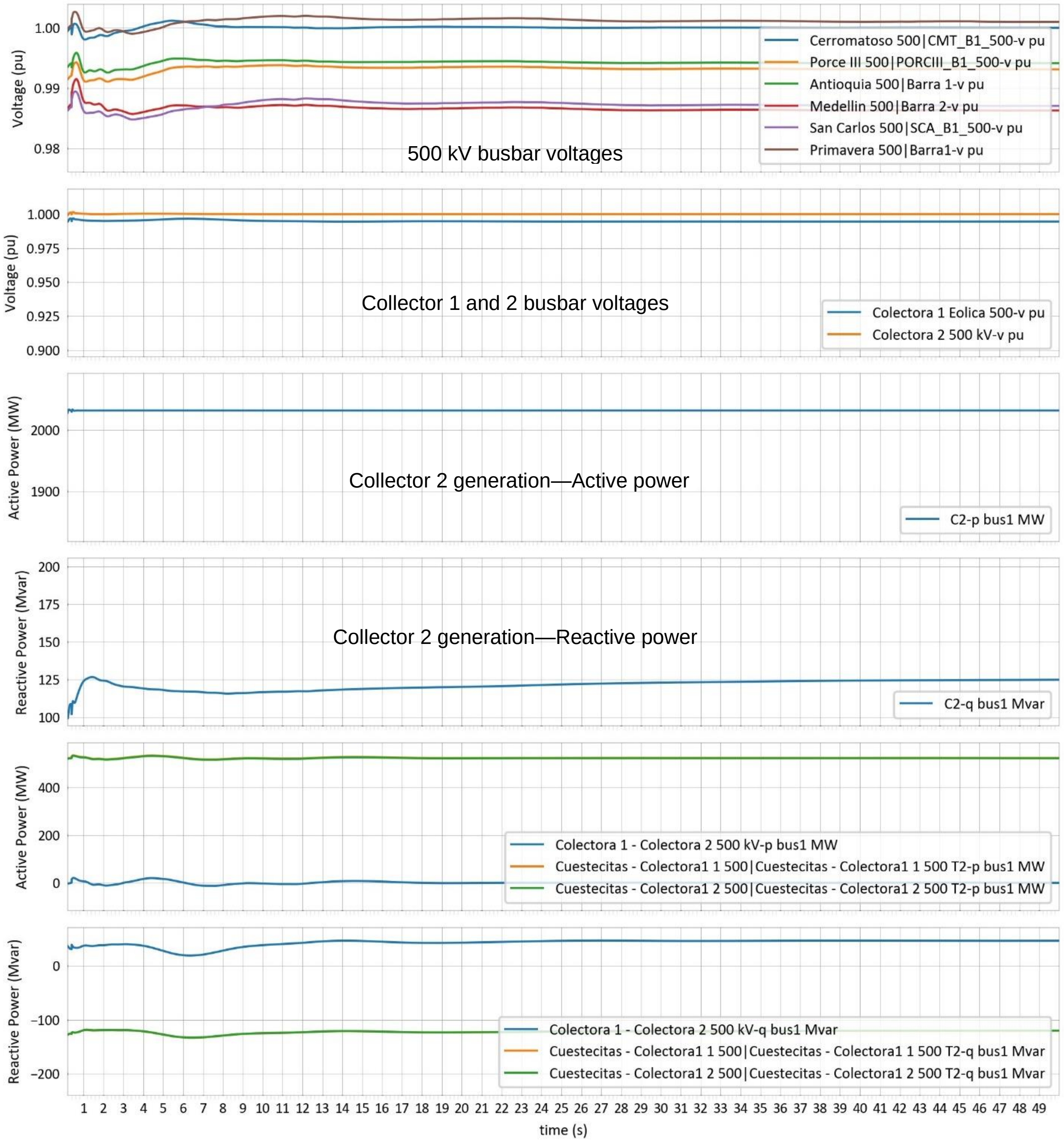


Figure 3-17 AC system response (Contingency: largest synchronous generator outage—300 MW Ituango 1, Study case: 2028 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

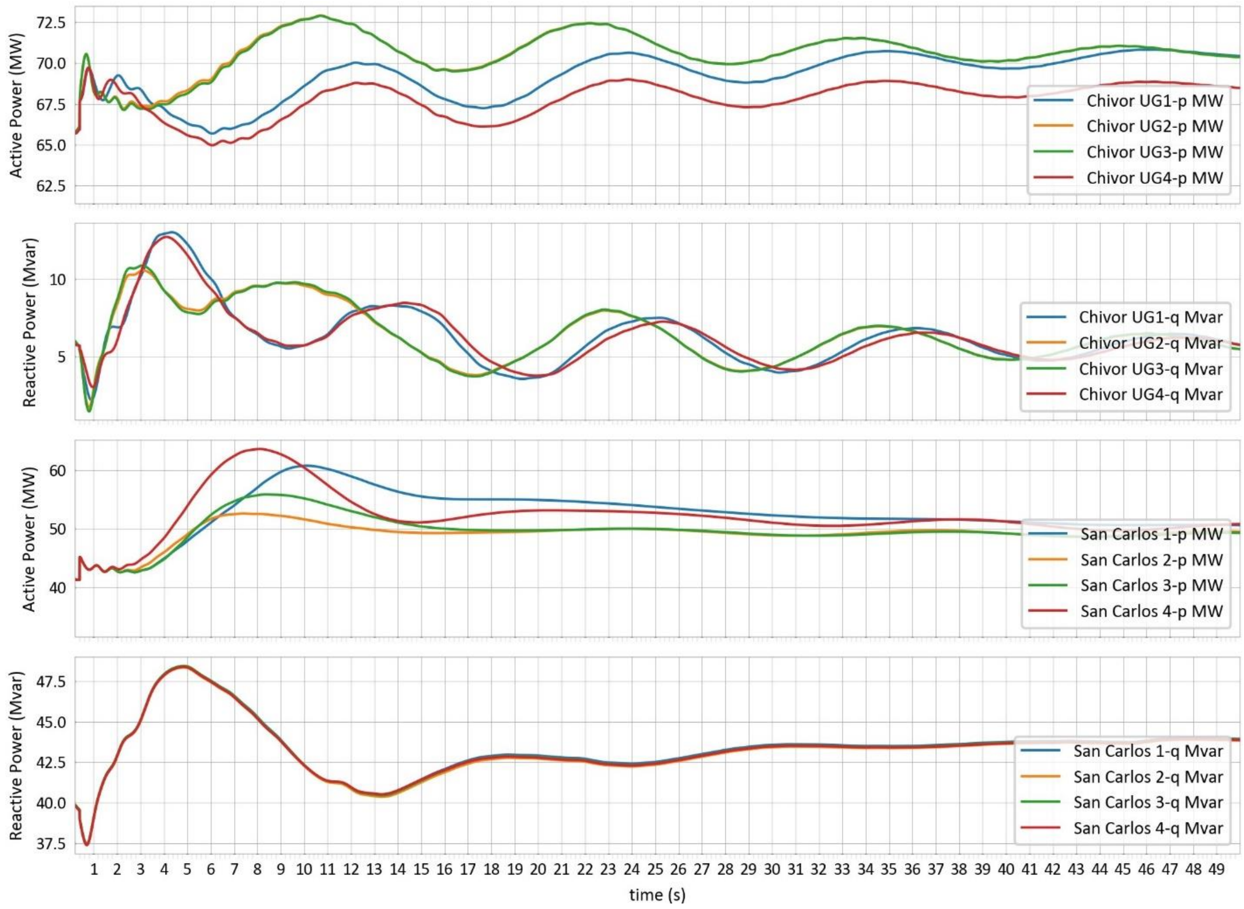


Figure 3-18 Generator governor responses of selected synchronous generators to address the power mismatch (Contingency: largest synchronous generator outage—300 MW Ituango 1, Study case: 2028 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

3.4.2.2 HVDC related Contingencies

Following contingencies are simulated:

- Temporary AC fault at each converter bus bar
- HVDC pole outage
- HVDC bipole outage
- Collector 1— Collector 2 500 kV AC transmission line outage

3.4.2.2.1 Temporary AC Fault at HVDC Terminals

The HVDC and AC system performance meet the study criteria under a temporary fault at the inverter and rectifier AC bus bar.

As an example, the simulation results for a rectifier and inverter fault in the 2032 Max Dem Max Gen study case are discussed in the following sections.

3.4.2.2.1.1 Temporary AC fault at VSC HVDC rectifier busbar (Station A)

The simulation results for a temporary fault at the rectifier AC busbar in the 2032 Max Dem Max Gen study case is discussed in this section. Figure 3-19 shows the transient response of the VSC HVDC bipole. Figure 3-20 shows the transient response of the AC system. For the rectifier side fault, the system recovers well and the HVDC performance is good.

Note that the spikes shown at the moment of fault inception and fault clearing are a result of the algebraic network (admittance matrix) solution used in the RMS simulations. For example, the rectifier AC voltage jumps to about 3.2 pu at the fault clearances and this is due to the numerical solution errors. These changes are ignored in the transient stability simulations and need to be evaluated using EMT simulations.

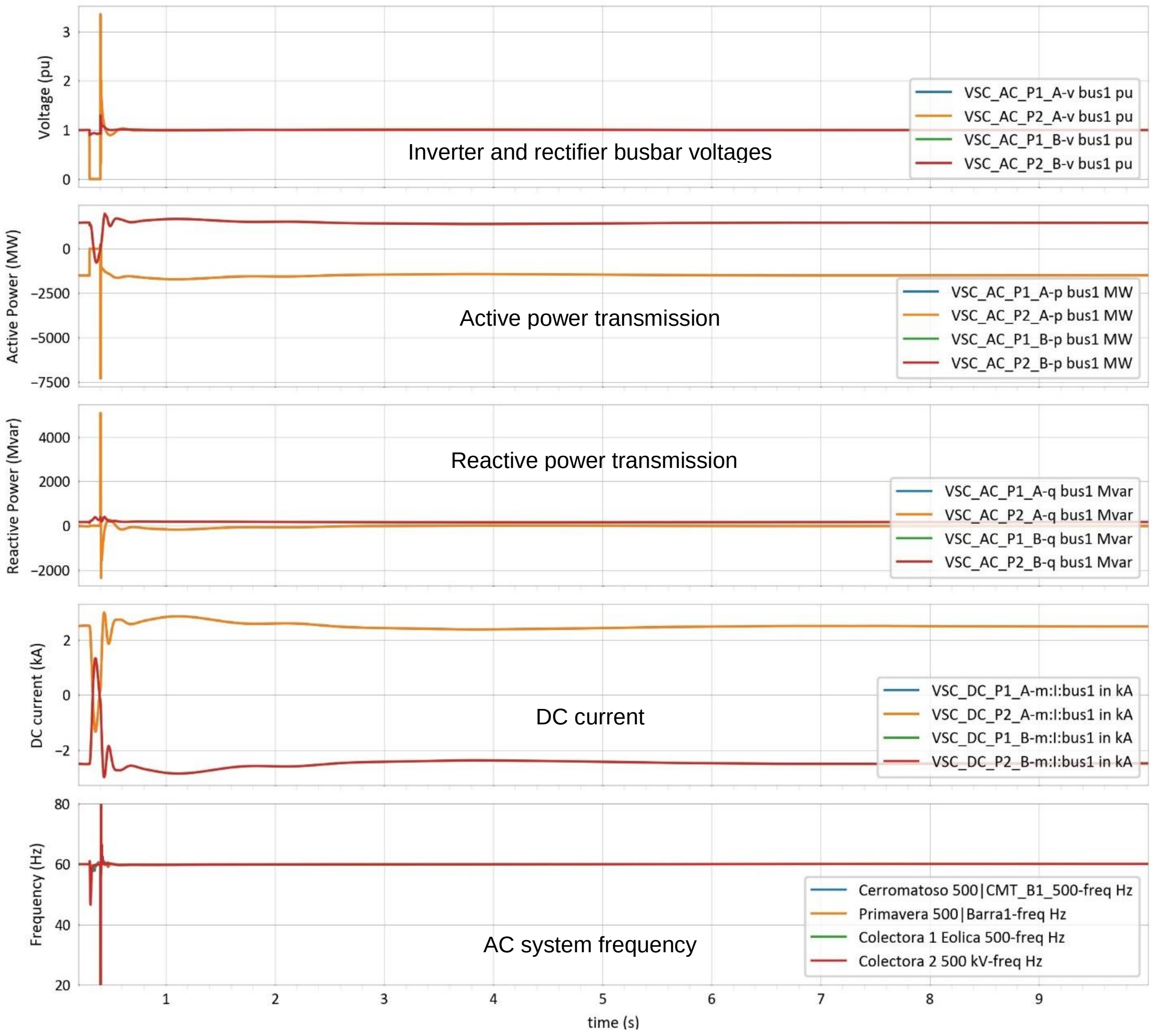


Figure 3-19 VSC HVDC response (Contingency: temporary AC fault at rectifier busbar, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

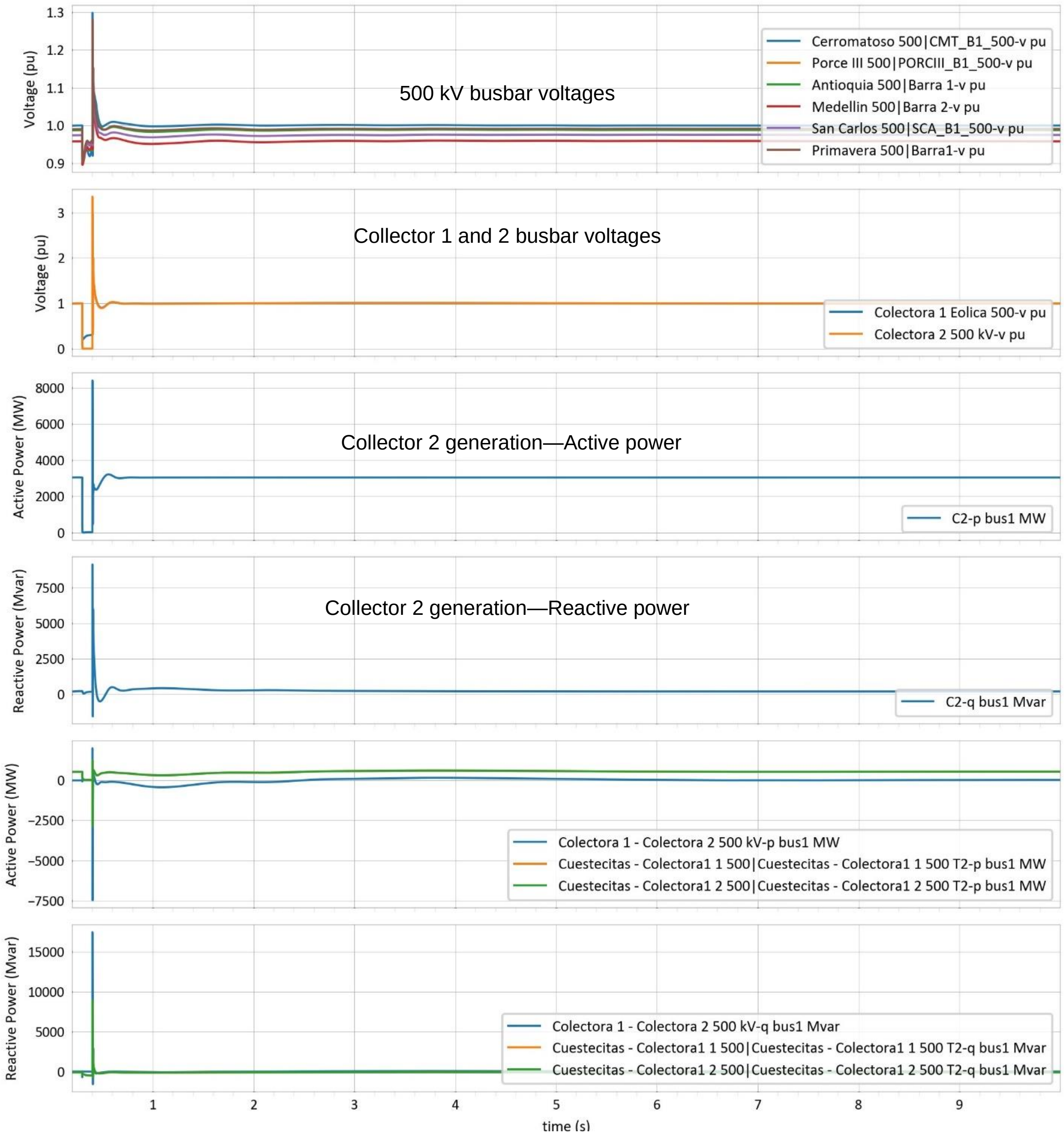


Figure 3-20 AC system response (Contingency: temporary AC fault at rectifier busbar, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

3.4.2.2.1.2 *Temporary AC fault at VSC HVDC inverter busbar (Station B)*

The simulation results for a temporary fault at inverter AC busbar in the 2032 Max Dem Max Gen study case are discussed in this section. Figure 3-21 shows the transient response of the VSC HVDC bipole. Figure 3-22 shows the transient response of the AC system. For the inverter side fault, the system recovers well and the HVDC performance is good. Note that there are some mild oscillations in the HVDC power transfer can be observed. This is due to the grid forming characteristics of the system. Due to the disturbance, the electromechanical oscillations of generators are excited and the grid forming rectifier is absorbing some of these oscillations in the AC system and helping to damp down quickly.

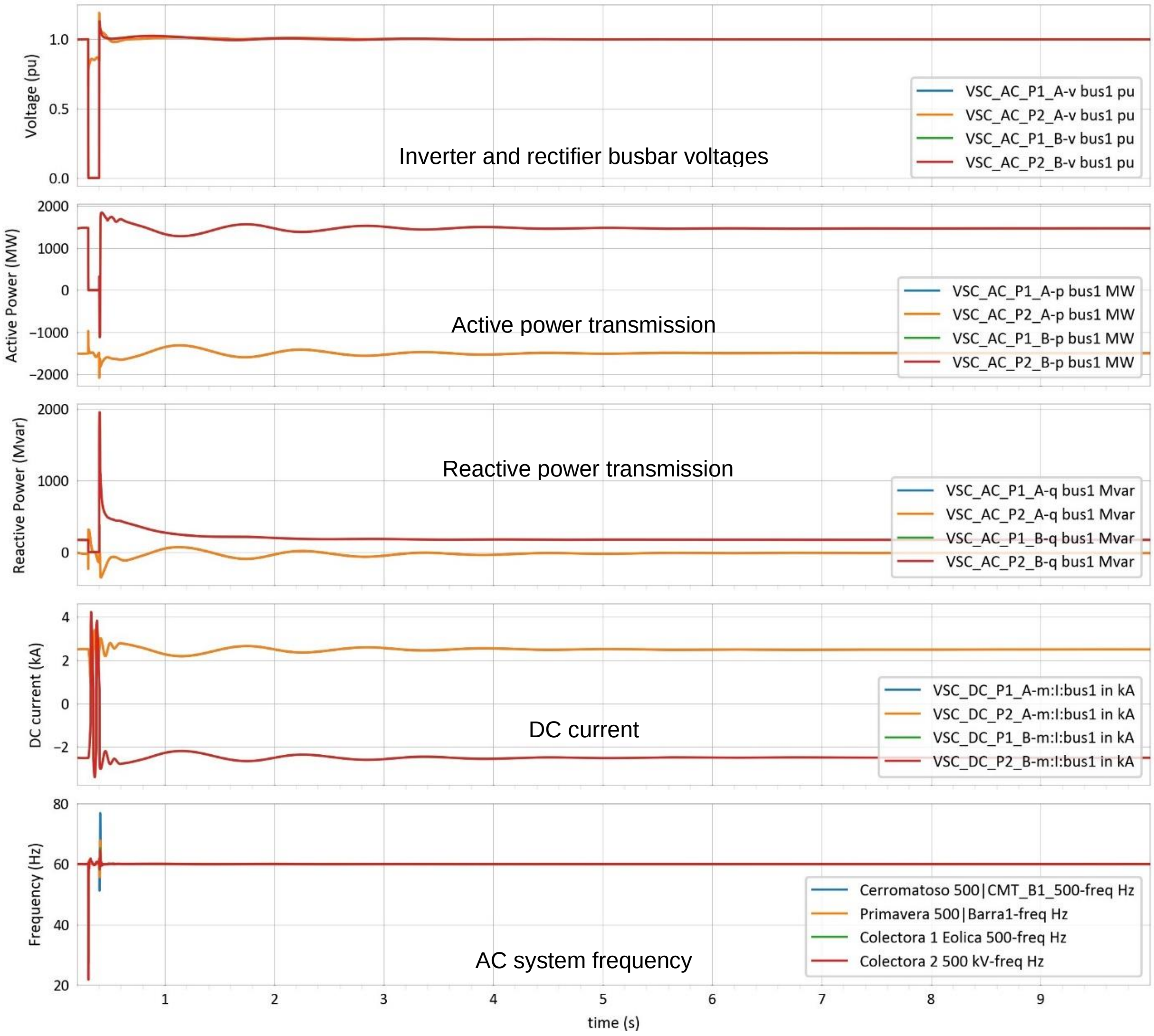
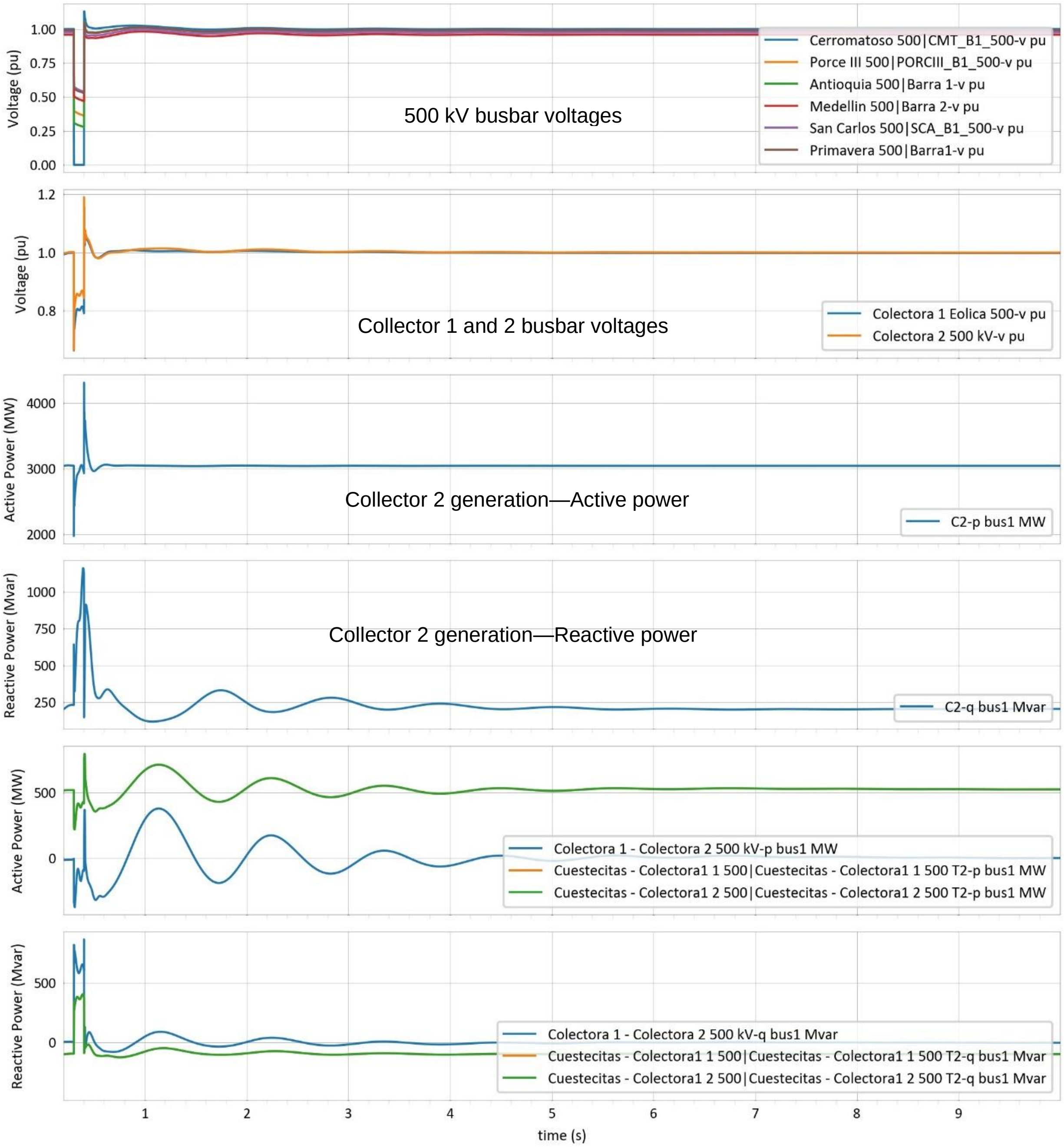


Figure 3-21 VSC HVDC response (Contingency: temporary AC fault at inverter busbar, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)



500 kV busbar voltages

Collector 1 and 2 busbar voltages

Collector 2 generation—Active power

Collector 2 generation—Reactive power

Figure 3-22 AC system response (Contingency: temporary AC fault at inverter busbar, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

3.4.2.2.2 HVDC Pole Outage

The Colombian grid code does not allow to curtail the generation for N-1 contingencies. The HVDC pole outage is also an N-1 contingency and therefore the system is required to be designed to keep the generation intact. For a pole outage, the transmission capacity of the VSC HVDC bipole system is reduced to 1500 MW. Assuming no overload capacity, the system should be able transmit the excess power using the 500 kV AC line between Collector 1 and Collector 2. Therefore, in 2032 study cases, the system should be capable of diverting about 1500 MW to the 500 kV AC transmission line.

In 2028 study cases, each pole initially transmits only 1000 MW and the active power transmission in the healthy pole can be increased to 1500 MW. Therefore only 500 MW needs to be diverted to the AC system. However, during this study, the power ramping feature was not considered, and the entire power mismatch was diverted through the AC system (i.e., worst case scenario).

3.4.2.2.2.1 Pole outage in operational year 2028

The HVDC system performance and the AC system performance for a pole outage in the 2028-Max Dem Max Gen study case are shown in Figure 3-23 and Figure 3-24 respectively. In this case, both poles are initially transmitting 1000 MW. The 500 kV line between Collector 1 and Collector 2 is initially lightly loaded (transmits less than one megawatt). When the HVDC pole-2 is tripped after a DC fault, the power transmission in the 500 kV line from Collector 2 to Collector 1 is increased to about 1000 MW. As described earlier, this transfer can be reduced to about 500 MW by increasing the remaining pole power reference to 1500 MW.

The simulations for all the study cases in 2028 show good results and the dynamic performance is within system performance criteria. The detailed simulation results are provided in Appendix C.

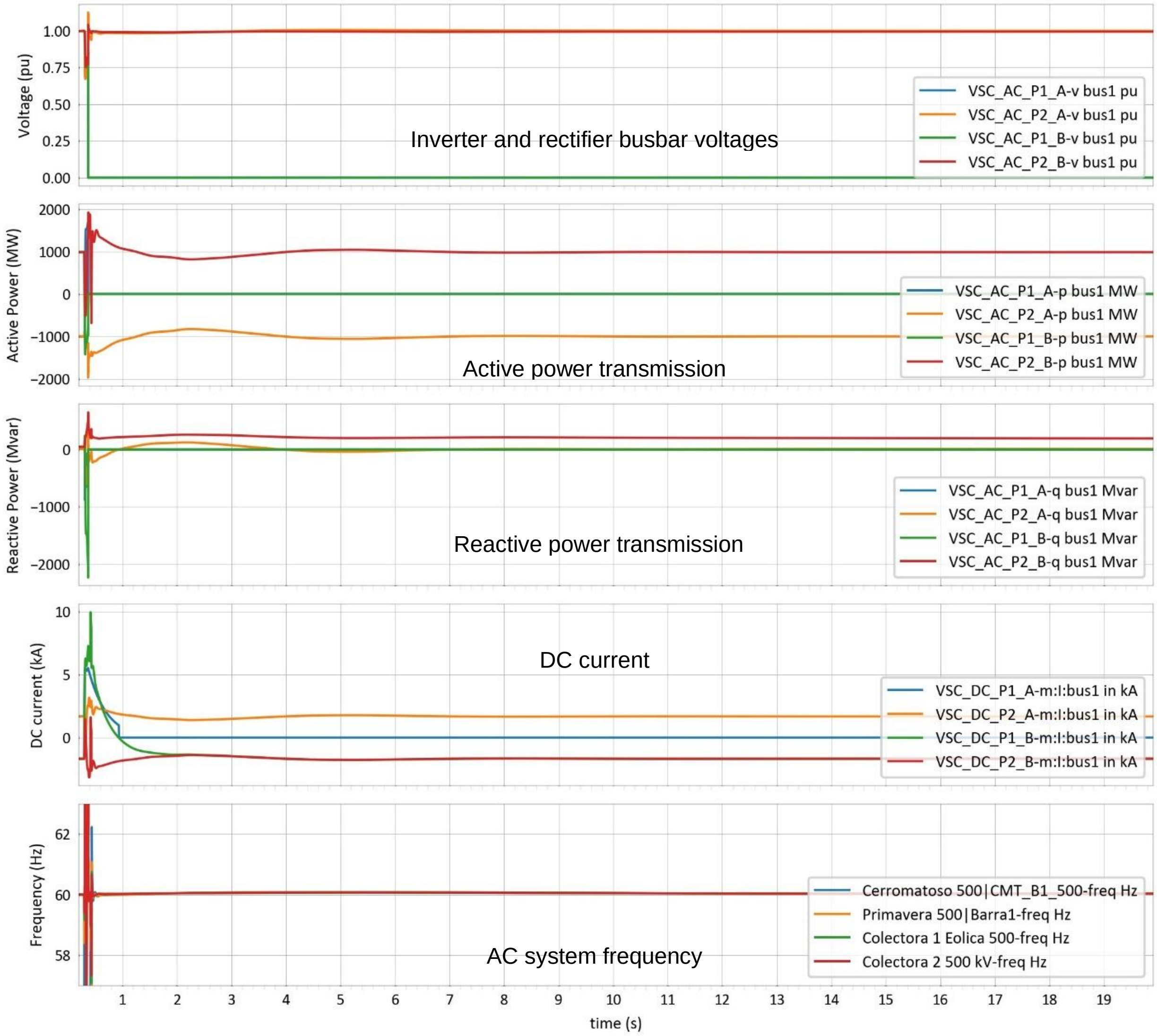


Figure 3-23 VSC HVDC response (Contingency: VSC HVDC pole outage, Study case: 2028 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

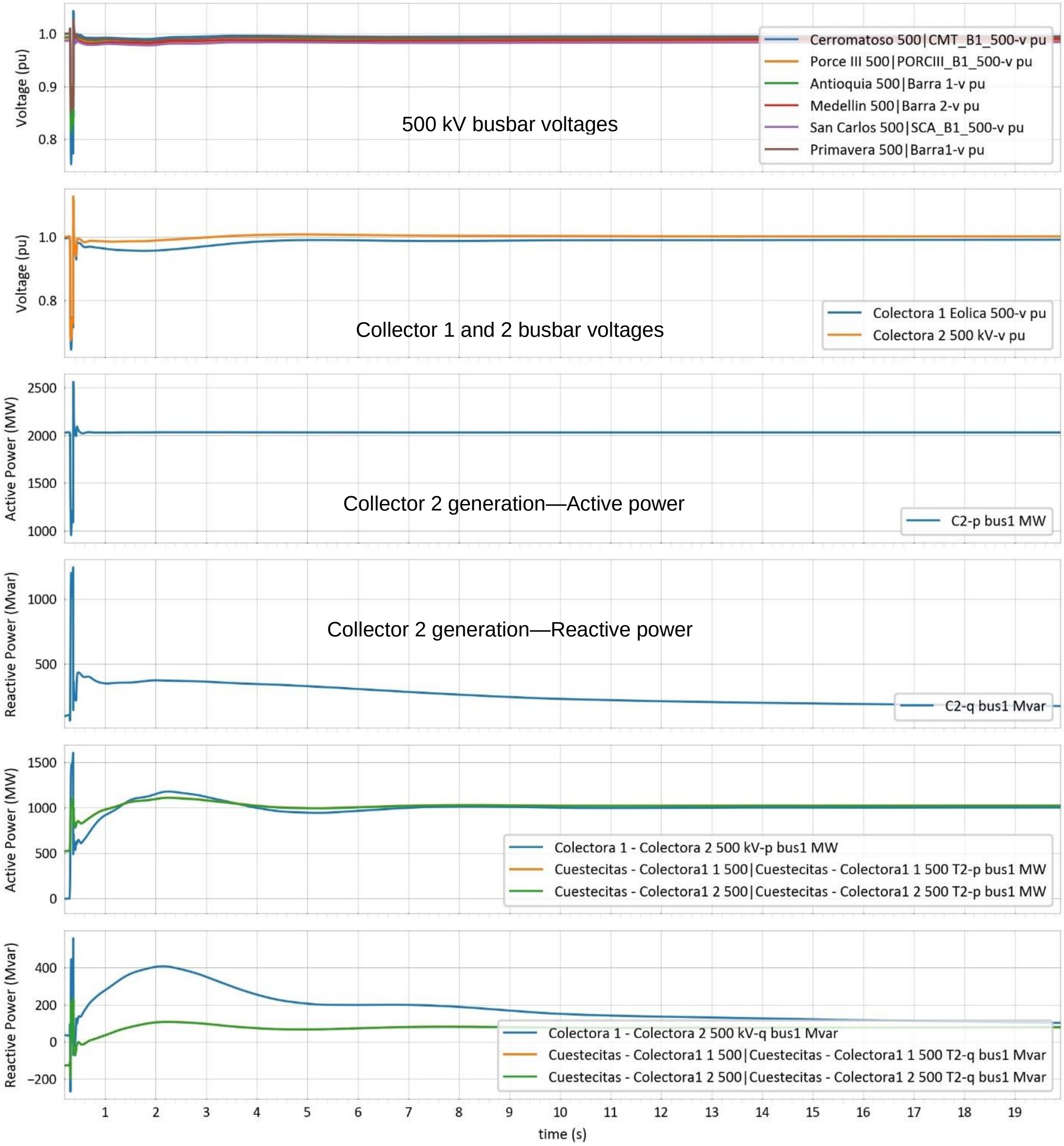


Figure 3-24 AC system response (Contingency: VSC HVDC pole outage, Study case: 2028 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

3.4.2.2.2.2 Pole outage in operational year 2032

For the HVDC pole outage, the system recovery was not acceptable in both study cases in operational year 2032 under the HVDC pole outage. The HVDC system performance and the AC system performance for a pole outage in the 2032 Max Dem Max Gen study case are shown in Figure 3-25 and Figure 3-26 respectively. In this case, both poles are initially transmitting 1500 MW. The 500 kV line between Collector 1 and Collector 2 is initially lightly loaded (transmits about one megawatt). The 500 kV double circuit lines between Collector 1 and Cuestecitas are initially transmitting about 520 MW in each circuit.

During a HVDC pole outage, about 1500 MW needs to be transmitted to the AC system using the 500 kV line from Collector 2 to Collector 1. Furthermore, the AC system from Collector 1 should be able to transmit the additional power of about 1500 MW to the load centers. The simulation results show that the voltage does not recover sufficiently to be able to transmit the power in the AC system. This eventually leads to system collapse.

The possible solutions to achieve an acceptable performance are discussed in the following section.

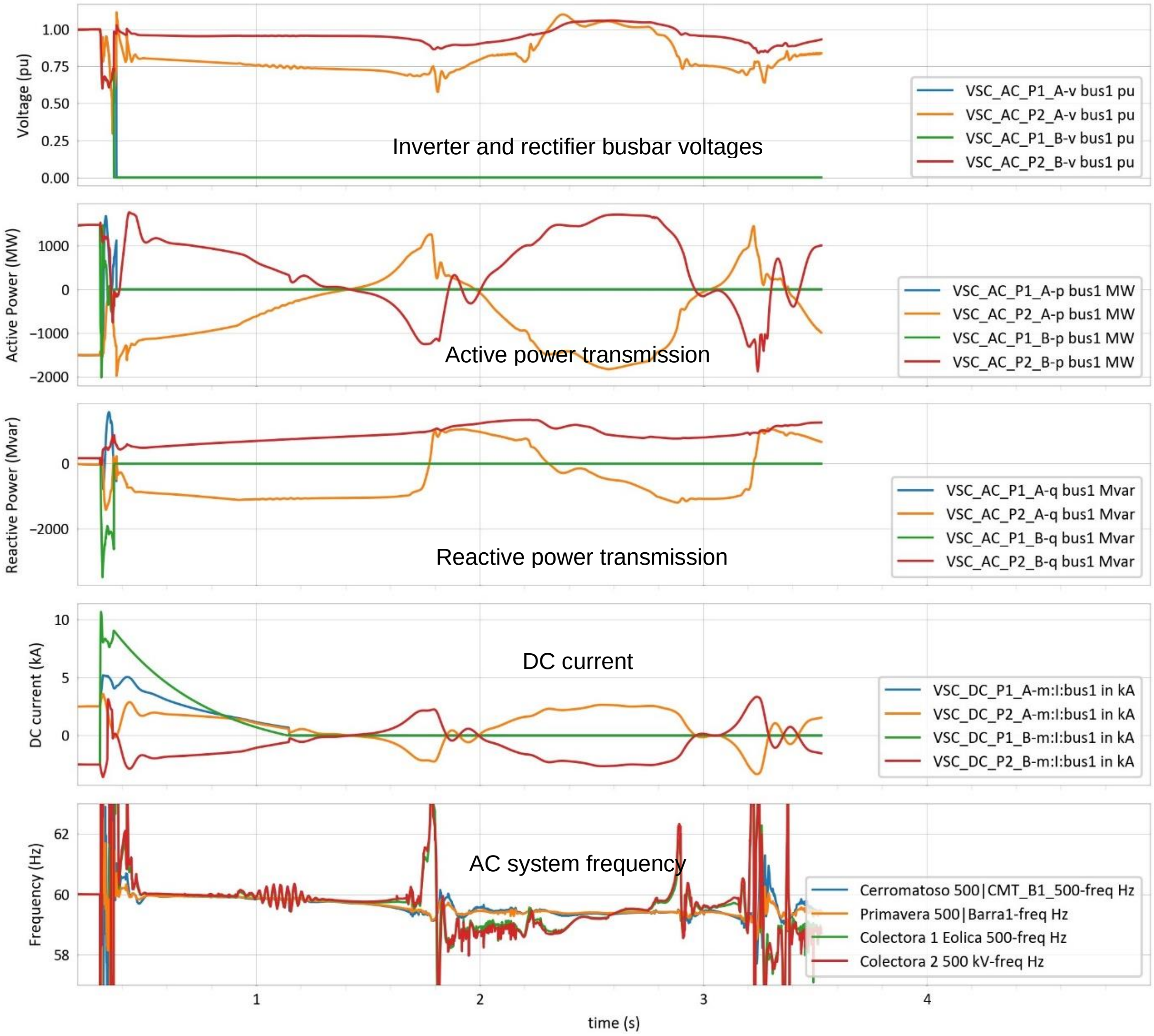


Figure 3-25 VSC HVDC response (Contingency: VSC HVDC pole outage, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

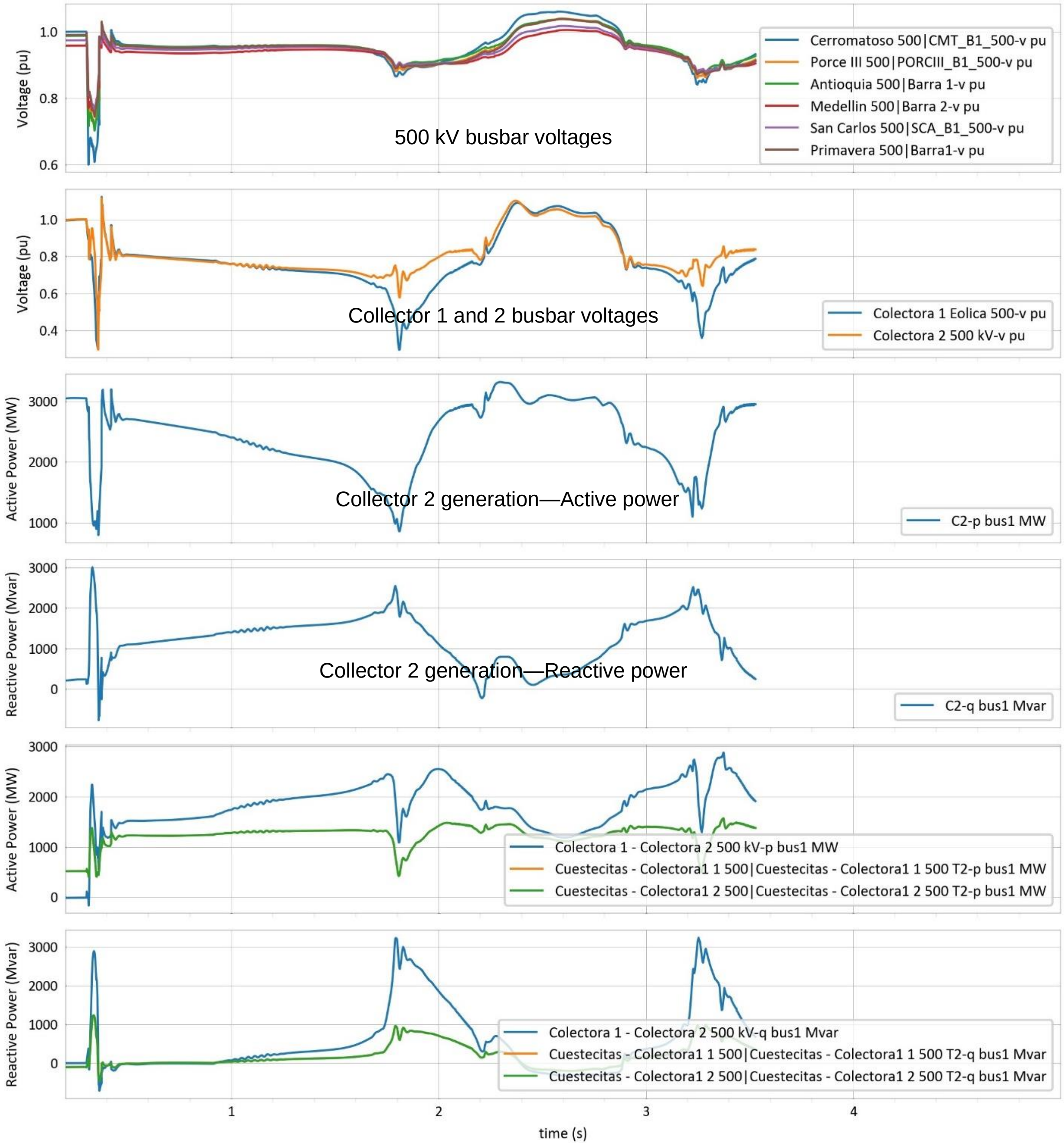


Figure 3-26 AC system response (Contingency: VSC HVDC pole outage, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

3.4.2.2.2.2.1 Requirements for successful recovery under a pole outage

Our investigations showed that the following measures are required in order to obtain an acceptable performance for the pole outages in 2032 study cases:

- Improving the post-disturbance voltage performance of the 500 kV AC system parallel to the HVDC system
- Increasing the transient current handling capability of the HVDC system

Figure 3-27 shows the in-service transmission line reactors on 500 kV network in the 2032 Max Dem Max Gen study case. Tests were performed to trip the line reactors after the pole outage to improve the 500 kV system AC voltage and hence enable more power transfer.

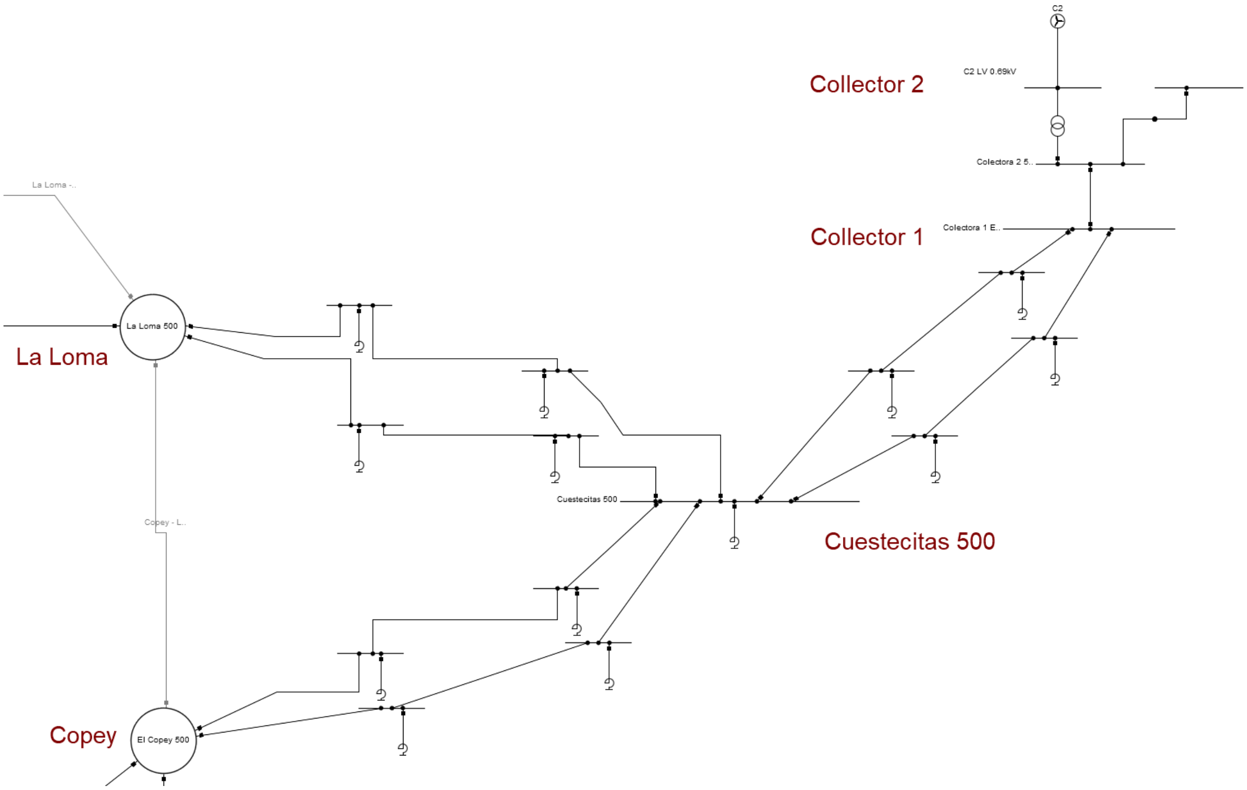


Figure 3-27 Transmission line reactors in 500 kV network in 2032 Max Dem Max Gen scenario near collector 1 and 2

The following reactors were tripped about 120 ms after the HVDC pole outage.

Table 3-14 List of reactors tripped after 120 ms of the HVDC pole outage

Reactor name	Rated reactive power (Mvar)
Rea Colectora - Cuestecitas 1 60 MVAR	60
Rea Cuestecitas - Colectora 1 60 MVAR	60

Reactor name	Rated reactive power (Mvar)
Rea Colectora - Cuestecitas 2 60 MVAR	60
Rea Cuestecitas - Colectora 2 60 MVAR	60
Rea LLoma - Cuestecitas 2 120 MVAR	120
Rea Cuestecitas - LLoma 2 120 MVAR	120
Rea Cuestecitas - Copey 2 84 MVAR	84
Rea Cuestecitas - Copey 84 MVAR	84
Rea Copey - Cuestecitas 2 84 MVAR	84
Rea LLoma - Cuestecitas 120 MVAR	120
Rea Copey - Cuestecitas 84 MVAR	84
Rea Cuestecitas - LLoma 120 MVAR	120
Comp. Reactiva 84 Mvar Cuestecitas 500	42

The additional support obtained from tripping the reactors was not sufficient to ensure the transient recovery of the system. Further tests were performed by increasing the transient current handing capability of the healthy VSC HVDC pole. The transient current limit was increased from 1.2 pu to 1.3 pu.

The pole outage for the 2032 Max Dem Max Gen study case was repeated with the following mitigation measures:

- The 12 line reactors listed in Table 3-14 are cross-tripped 120 ms after the pole outage
- HVDC current rating is increased to 1.3 pu.

The HVDC system performance and the AC system performance are shown in Figure 3-28 and Figure 3-29 respectively. Initially, the power transfer in the healthy pole increases to about 2000 MW and drops to the rated value in about 1 seconds. This means that the transient current increase to 1.3 pu for one or two seconds is sufficient for the proper recovery of the HVDC system.

The AC system voltages recover well with reactor cross-tripping. The detailed simulation results are given in Appendix D.

An alternative way of improving the transient voltage performance of the 500 kV parallel AC transmission network (instead of cross-tripping the reactors) is to install dynamic reactive power compensation devices such as STATCOM and SVC. It is recommended to perform a detailed study to evaluate the reactive power compensation in the AC system for different operating conditions including the heavy loading conditions during an HVDC pole outage.

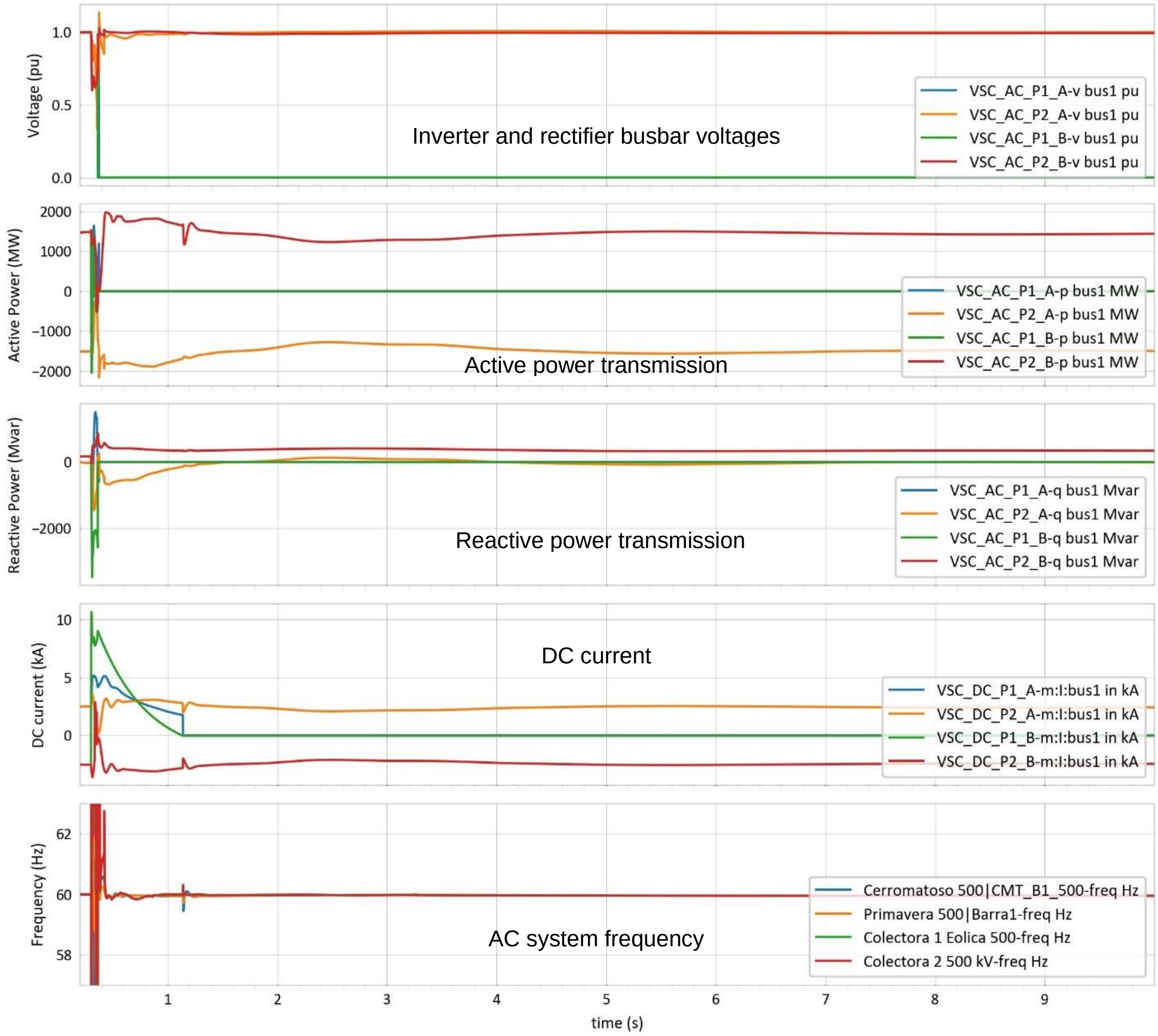


Figure 3-28 VSC HVDC response under increased converter current rating (Contingency: VSC HVDC pole outage, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

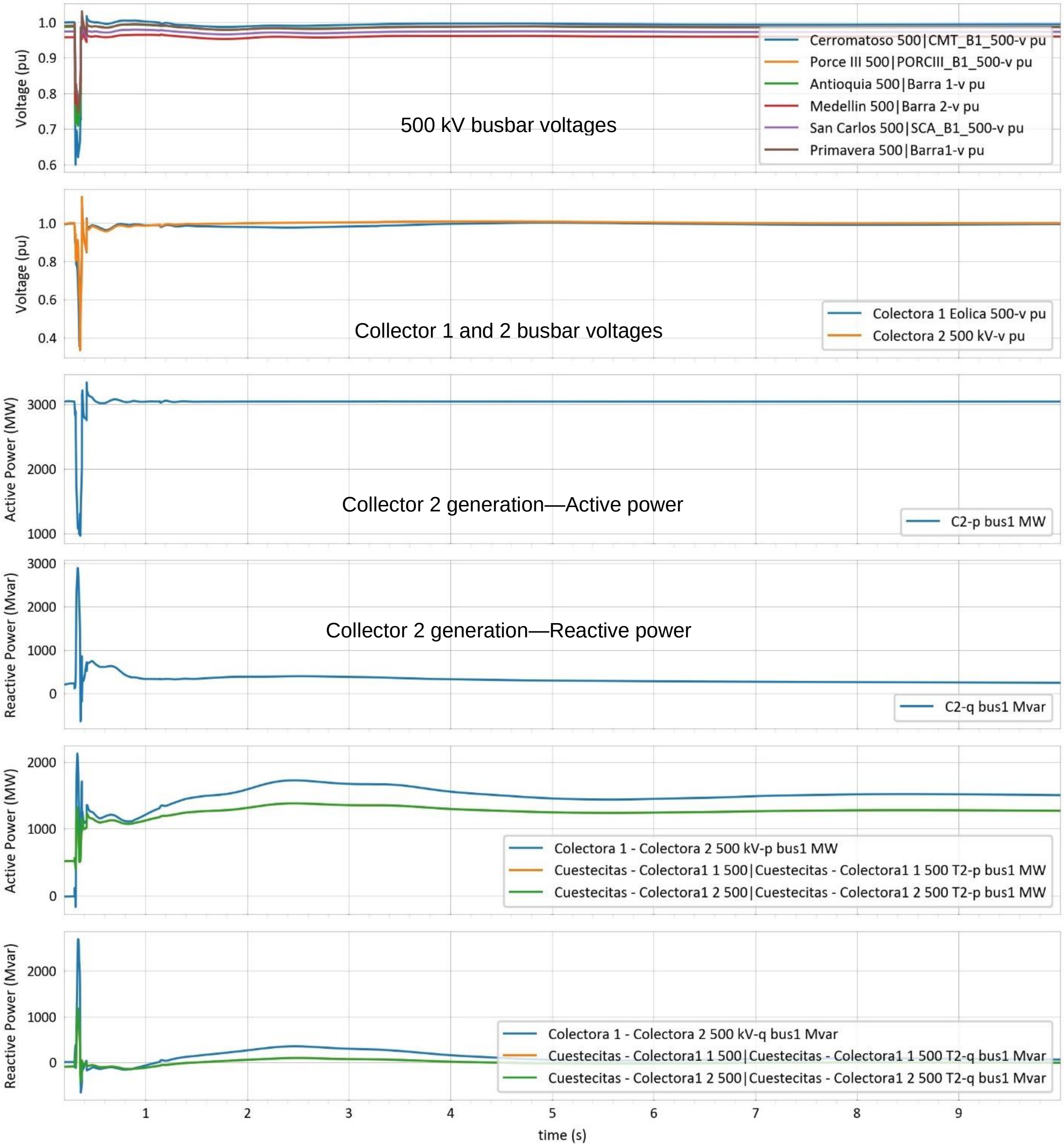


Figure 3-29 AC system response under increased VSC HVDC converter current rating (Contingency: VSC HVDC pole outage, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

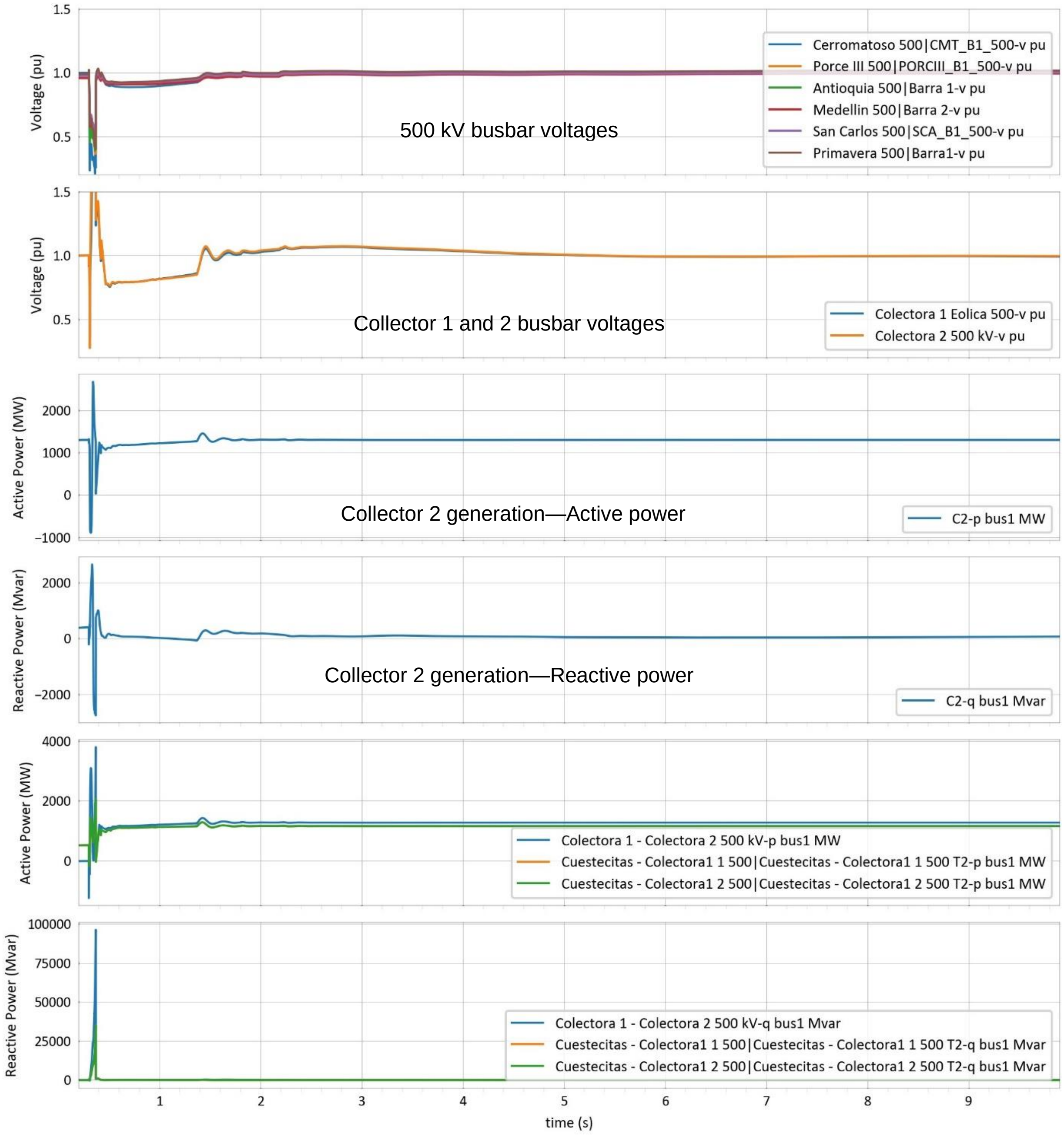
3.4.2.2.3 HVDC Bipole Outage

During the HVDC bipole outage, the only available path to transmit the Collector 2 power generation is the 500 kV transmission line from Collector 1 to Collector 2. In the 2028 study cases, in which the VSC HVDC transmits 2000 MW, the 500 kV line from Collector 1 to Collector 2 gets loaded above 95% of its thermal capacity during a bipole outage. In the 2032 study cases, in which the VSC HVDC transmits 3000 MW, there is no feasible power flow solution as the 500 kV line from Collector 1 to Collector 2 is loaded to about 150% of its thermal limit. Therefore, it is required to cross trip some of the generation at Collector 2. The bipole outage is an N-2 outage. Therefore, the load and generation can be shed to maintain the system stability. The bipole outage was simulated in DIgSILENT and a portion of the Collector 2 generation was tripped to maintain stability. The required amount of generation trip was determined iteratively. The UFLS included in the DigSILENT power system model was expected to respond to the system frequency drop by appropriately shedding the loads. Note that the transmission line reactors listed in Table 3-14 were also cross tripped after the bipole outage to improve the 500 kV AC network voltage. This helped to transfer more power along the AC system. During the bipole outage, about 1700 MW of generation at Collector 2 was cross tripped in 2032 Max Dem Max Gen study case and the load shedding was observed as a result of the system wide frequency drop. Figure 3-30 shows the transient response of the AC system during the bipole outage in the 2032 Max Dem Max Gen study case.

The accuracy of the simulation results during the bipole outage depends on several aspects of the system model used for the study including the accurate representation of the following:

- Renewable plants in Collector 1 and 2
    - fault ride-though characteristics
    - controller and protection algorithms
- UFLS scheme

Mainly the renewable plant models in DIgSILENT may not work properly under weak grid conditions created after the bipole trip. Therefore, it is recommended to perform the bipole outage study using an electromagnetic transient simulation model. A detailed study is usually carried out during the design stage of the HVDC. Accordingly, more accurate amounts for generation cross trip can be determined during the design stage of the HVDC.



500 kV busbar voltages

Collector 1 and 2 busbar voltages

Collector 2 generation—Active power

Collector 2 generation—Reactive power

Figure 3-30 AC system response under the VSC HVDC bipole outage (Cross tripped Collector 2 generation: 1700 MW, Study case: 2032 Max Dem Max Gen, VSC HVDC interconnection location: Cerromatoso)

3.4.2.2.4 Outage of 500 kV line between Collector 1 and 2

The 500 kV line between Collector 1 and 2 carries only a few megawatts during system intact conditions. Therefore, tripping of this line should not cause a significant impact to the system performance. However, this outage isolates the Collector 2 and the HVDC rectifier from the rest of the system. Since the HVDC converter is already in the grid forming mode, this would not be a concern. However, DIgSILENT simulations showed numerical issues when the line is tripped. It may not be possible to perform such a simulation using RMS simulation tools such as DIgSILENT and an electromagnetic transient simulation would be required.

3.4.3 Study Results—Interconnection at Primavera

The same set of contingencies were repeated for the HVDC interconnection at Primavera. The detailed study results are provided in Appendix C. All the simulation results are very similar to the HVDC interconnection at Cerromatoso. The requirements for the HVDC pole outage are also identical. Therefore, in terms of transient stability, both of the interconnection options are acceptable and produce similar results.

3.4.3.1 Sensitivity to the high renewable energy penetration in Sahagun (Interconnection at Primavera)

A sensitivity study was performed to assess the system performance with the proposed renewable generation interconnected at Sahagun area. The *Med Dem Max Gen* study cases provided by UPME for both operational years 2028 and 2032 were considered for the study.

The system performance was assessed under the key contingencies related to the VSC HVDC, loss of the heavily loaded transmission lines connected to the inverter bus at Primavera and for the loss of the largest synchronous generator as listed below:

- VSC HVDC-Three phase fault, clearing and recovery at Collector 2 AC bus (rectifier fault)
- VSC HVDC-Three phase fault, clearing and recovery at Primavera 500 kV AC bus (inverter fault)
- VSC HVDC-Permeant DC pole-to-ground fault (pole outage)
- Transmission line outages:
  - Primavera-Bacata 1 500 kV line outage
  - Cerro-Primavera 1 500 kV line outage
  - Primavera-San Carlos 1 line outage
  - Primavera-Sogamoso T2 line outage
- Largest synchronous generator outage

The system dynamic performance for all the contingencies is acceptable for both operational years. The performance criteria in the Colombian grid code defined for transient voltage and frequency recovery were fully satisfied. All the generators remained in synchronism. No load shedding was observed. The proposed reactor switching, and the increased transient current rating is required for successful system recovery under a VSC HVDC pole outage in the operational year 2032. These requirements are already discussed in Section 3.4.2.2.2.2.1 –Requirements for successfully recovery under a pole outage.

As example cases, the HVDC and the AC system performance for the *HVDC pole outage* are shown in Figure 3-31 and Figure 3-32.

The HVDC and the AC system performance for the *Primavera-Bacata 1 500 kV line outage* are shown in Figure 3-33 and Figure 3-34.

Note that the numerical spikes at fault inception and clearance are ignored.

The detailed dynamic simulation results for both operational years under each contingency are provided in Appendix C.

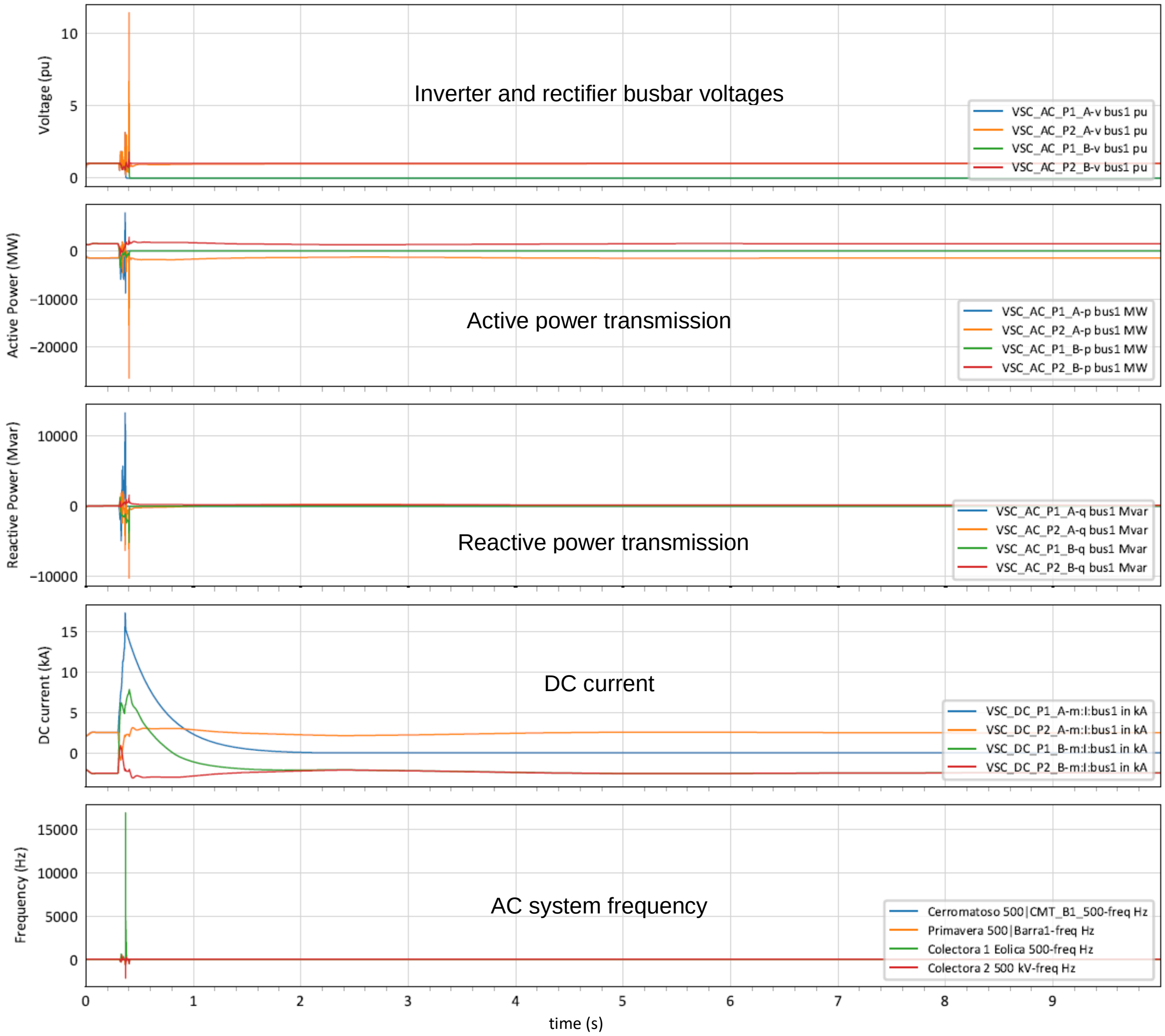


Figure 3-31 VSC HVDC response under increased converter current rating (Contingency: VSC HVDC pole outage, Study case: 2032 Med Dem Max Gen, VSC HVDC interconnection location: Primavera)

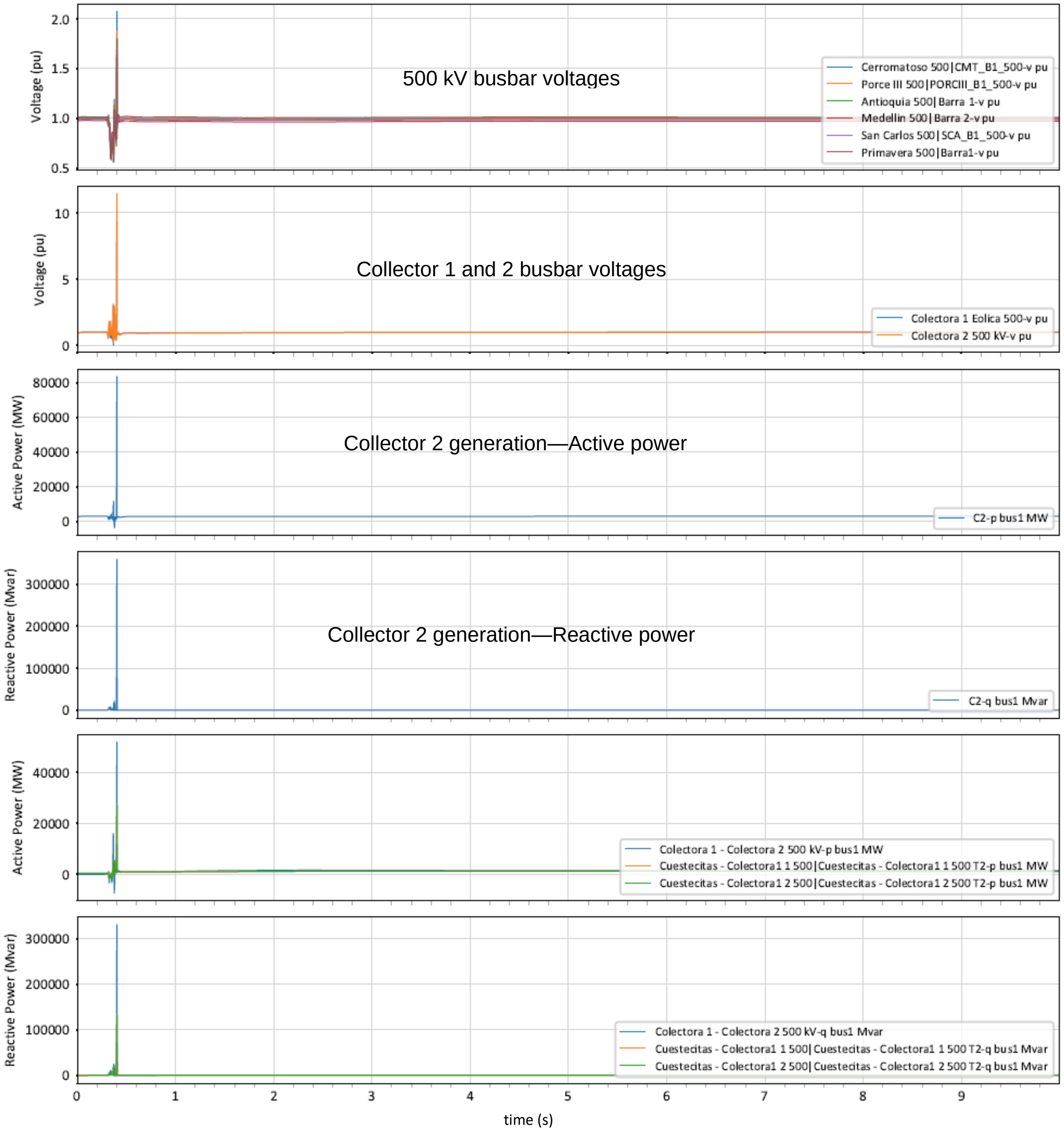


Figure 3-32 AC system response under increased VSC HVDC converter current rating (Contingency: VSC HVDC pole outage, Study case: 2032 Med Dem Max Gen, VSC HVDC interconnection location: Primavera)

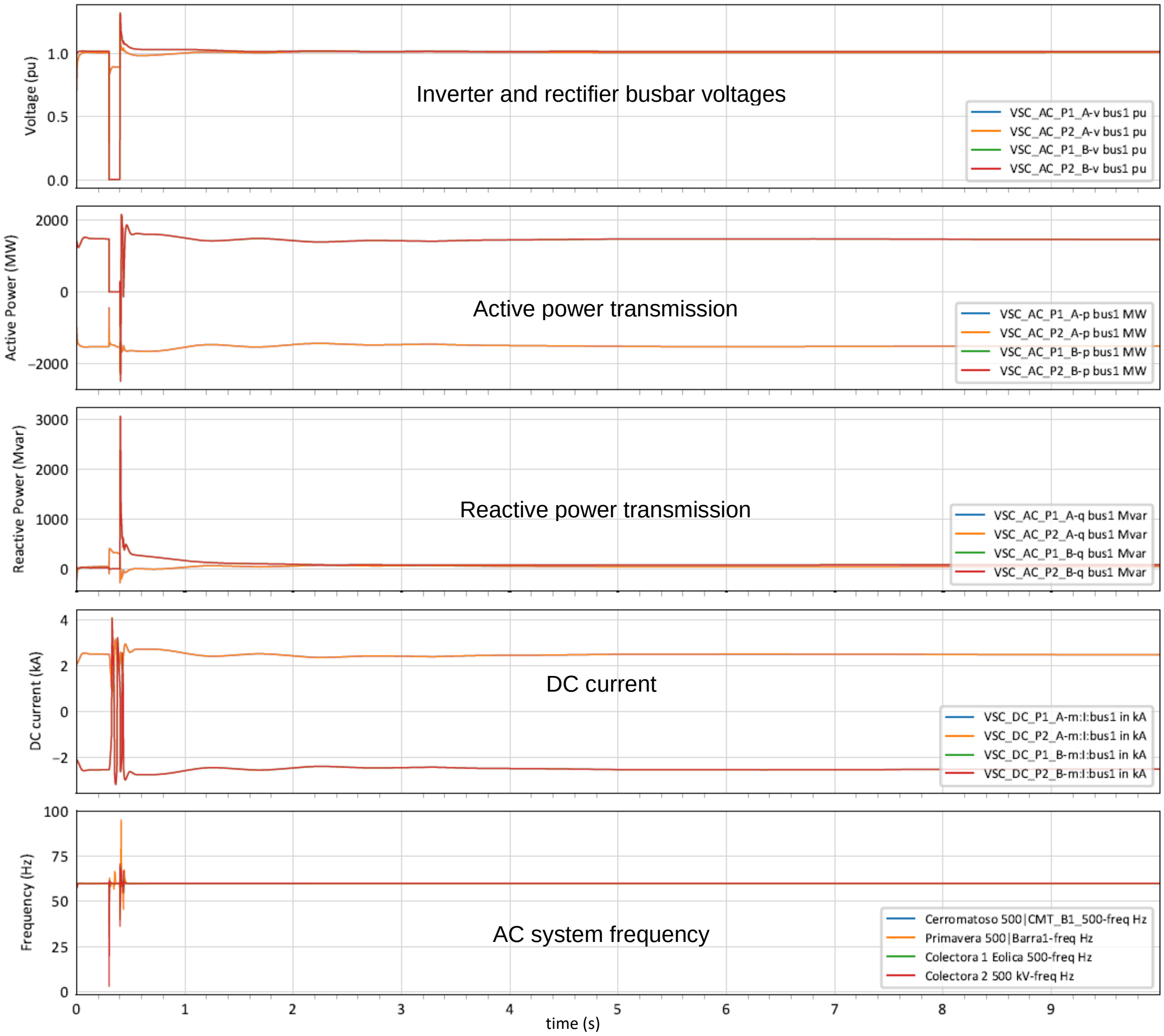


Figure 3-33 VSC HVDC response (Contingency: Primavera-Bacata 1 500 kV line outage, Study case: 2032 Med Dem Max Gen, VSC HVDC interconnection location: Primavera)

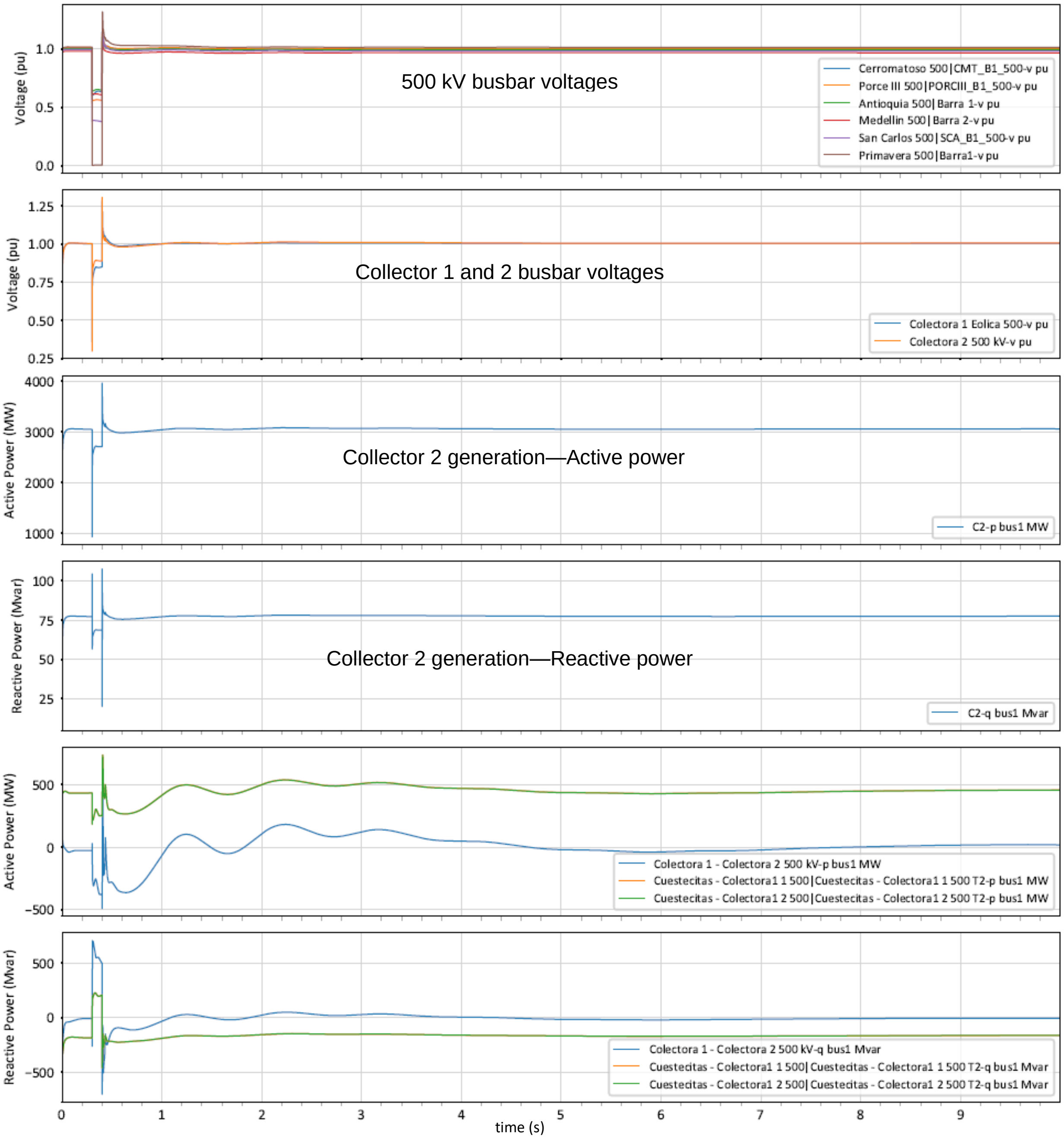


Figure 3-34 AC system response (Contingency: Primavera-Bacata 1 500 kV line outage, Study case: 2032 Med Dem Max Gen, VSC HVDC interconnection location: Primavera)

4. High-level Economic Assessment

4.1 Cost Evaluation

This section compares three interconnection options for the proposed 3000 MW VSC HVDC bipole transmission system from an economic perspective (The first two options are the same considered for the system studies and the third option was considered only for the economic assessment):

1. Interconnection to Cerromatoso using a 650 km long overhead transmission line
2. Interconnection to Primavera using a 780 km long overhead transmission line
3. Interconnection to Cerromatoso using a combination of 151 km long overhead transmission line and 665 km long submarine cable

The comparison is based on the capital cost of the converters, capital cost of the transmission line and cables, capital cost of the additional equipment required to reinforce the AC system and the cost of losses in the AC and DC systems over the lifetime of the transmission system.

4.1.1 Converter Cost

All three options utilize identical bipolar VSC converters rated for 3000 MW and +/- 600 kV. Cost of converters is therefore the same for all three options. Based on the recent survey of TGS the capital cost for two VSC converters is in the range of $1.2 billion to $1.35 billion. Note that these values are for standard voltage source converters designed to operate in grid-following or islanded mode. The rectifier terminal at La Guajira will operate in grid-forming mode and there is a need for additional short term overcurrent capability which may affect the cost. In any case, the capital cost of converters is the same for the three options and does not affect the selection of one option over the others. The operation and maintenance cost of the converters are also the same for the options and therefore has no impact on the selection of the option.

4.1.2 Cost of Transmission Line

The cost of a typical overhead HVDC transmission line at +/-600 kV in Colombia is estimated at $330,000 per kilometer. The line is assumed to include two Dedicated Metallic Return (DMR) conductors. The cost of the right-of-way (ROW) should be added to this cost. For this analysis the cost of ROW is estimated at $100,000 per kilometer for all options. Note that submarine cable does not incur this item of cost.

The 600 kV submarine HVDC cable is available today and installed in the Western Link HVDC project in the UK. Based on the information available, the cost of this cable is $1.1 million per kilometer. It is assumed that there are also two medium voltage cables for DMR. The cost of these medium voltage cables is estimated at $250,000 per kilometer. Considering two HV cables and two MV cables the cost of cable will be $2.7 million per kilometer distance. Based on this, the cost of transmission lines for the three options are as summarized in Table 4-1 below[1].

Table 4-1 Cost comparison for transmission line options

Option	Length of OHTL (km)	Length of cable (km)	Cost of OHTL (Mil USD)	Cost of Cable (Mil USD)	Cost of ROW (Mil USD)	Total cost (Mil USD)
1	650	0	214.5	0	65	279.5
2	780	0	257.4	0	78	335.4
3	151	665	49.8	1796	15.1	1860.4

4.1.3 Cost of Losses

The load flow studies provide the losses in the HVDC system and the total losses of the AC system for various loading levels. From Table 4-2 below it is clear that the total losses of the AC system are dependent on the location of the Southern terminal of the HVDC link. It is also dependant on the load flow scenario. For this analysis the losses in the AC system are assumed to be the average of the minimum demand-minimum generation and maximum demand-maximum generation cases in year 2032. For the purpose of this analysis the typical HVDC losses for the year 2032, shown in Table 4-2, will be used.

Table 4-2 - AC and HVDC system losses

Year	Study Case	AC system Losses without HVDC (MW)			HVDC system losses (MW)		
		Cerromatoso	Primavera	Δ AC Losses	Cerromatoso	Primavera	Δ DC Losses
2032	Min Dem Min Gen	206	187	19	101.4	113.4	-12
	Max Dem Max Gen	428	365	63			

Considering a cost of energy of $60/MWh and an interest rate of 6%, the present value of losses over 30 years is:

Cost of losses = [(60 USD x 8760 hr)/0.06] x [1- 1/ (1+0.06) ^30] = **7.2 Mil USD/MW**

Based on this the cost of losses for the three options are as provided in Table 4-3. For the losses in the AC system, option 1 is considered the base case and for other cases the change in losses is mentioned in the table.

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[1] Note that the cost of the 500 kV transmission line between Collector 1 and 2 is not included in this preliminary cost evaluation. The line is a common item for all options.

Table 4-3 - Cost of losses

Option	Δ AC losses (MW)	DC losses (MW)	Total cost of losses (Mil USD)
1	0	101.4	730
2	-41	113.4	521.3
3	0	127.3[2]	916.5

Note the values given in Table 4-3 are the total cost of losses in the entire AC system plus the HVDC link. Based on the information in Table 4-3, Option 2 provides a saving of **209 Mil USD and 395 Mil USD** in cost of losses over the lifetime of the HVDC system when compared to Option 1 and Option 3 respectively.

4.2 Cost Comparison

Considering the above items, the cost of the three options can be compared. Note that in addition to these items there are also some upgrades required for the AC system that are different among the options. As the details of these upgrades are not known at this time, this item of cost was left out of this analysis. Table 4-4 summarizes the costs of the three options. From this table it is clear that option 2 (converter station at Primavera) is the most cost-effective option. Please note that this analysis assumed the same cost for ROW for all three options. This may not be the case if the OHTL has to pass through populated areas. The analysis also does not consider the social factors such as public opposition to building new transmission lines.

Table 4-4 - Cost Comparison

Option	Description	Cost of Converter (Mil USD)	Cost of Line+Cable (Mil USD)	Cost of ROW (Mil USD)	Cost of Losses (Mil USD)	Total Cost (Mil USD)
1	Overhead line to Cerromotoso	1275	214.5	65	730	2285
2	Overhead line to Primavera	1275	257.4	78	521.3	2132
3	Overhead+submarine to Cerromatoso	1275	1846	15.1	916.5	4053

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[2] The losses were calculated based on the assumption that losses of the DC overhead line and cable are the same per unit length.

5. Implementation Aspects of the Project

5.1 Availability of Technology

The following VSC HVDC systems around the world are close to the ratings of the project planned in Colombia:

- Kunliulong HVDC Project (China – Awarded in 2018): 5000 MW Bipole, +/-800 kV overhead DC line
- Zhangbei DC Grid Project (China – Awarded in 2021): multi-terminal with largest converter of 3000 MW, +/- 500 kV
- UltraNet (Germany – being constructed): 2000 MW Bipole, +/- 380 kV overhead line
- Euro-Asia (Europe- Awarded to Siemens) 2000 MW Bipole, +/- 500 kV DC cable
- Sued Link (Germany – Being constructed) 2000 MW Bipole, +/- 525 kV overhead line + DC cable
- Sued Link (Germany – Being constructed) 2000 MW Bipole, +/- 525 kV overhead line + DC cable
- 2GW Offshore HVDC projects (many projects being planned in Europe): 2000 MW Bipole, +/- 525 kV DC cable

Most of the projects have the bipole rating of about 2000 MW. The Chinese projects are up to 5000 MW. The most common DC voltage for 2000 MW systems is 525 kV and this can be utilized for both overhead and cable transmission. The Chinese projects are using up to 800 kV (overhead lines). As of today, DC cables for VSC systems are available up to 600 kV (e.g., Prysmian P-Laser 600 kV cable).

Considering these facts, the proposed power transfer level, 3000 MW 600 kV, along with the 1.3pu transient current rating is at the edge of the available technology. TGS has also consulted several manufacturers in recent years, and they have confirmed the feasibility of such a project even at present despite the high cost. Furthermore, VSC technology has been fast evolved during the last decade and it is expected such ratings will be available worldwide (Note: these ratings are already achieved in China). Therefore, considering these facts, it is expected that the required technology will be available at a reasonable cost by the time of the implementation of this project.

The system studies performed during this project have showed the feasibility of integrating a 3000 MW 600 kV VSC HVDC to the Colombian AC system. It is understood that committing to a 3000 MW 600 kV VSC HVDC system at present is a challenge from a utility perspective.

In that case, UPME could decide to reduce the power transmission capability and the dc voltage to match the VSC HVDC transmission system in service today. The best available DC voltage would be 525 kV and it can be utilized for both overhead and cable transmission. If the rating of the HVDC is limited to 2500 MW, the DC current would be 2.38 kA. The steady state rating and the required transient rating can be achieved by using 3 kA IGBTs in the MMC values.

5.2 Common Challenges During Execution of an HVDC Project

The most common challenges during execution of an HVDC project are as follows:

1. In order to perform system studies, the required data must be available very quickly and the data must be in the required format for the study tools being used. In some cases where multiple stakeholders are involved obtaining data on time and in the proper format/detail is always a challenge. For example, if a wind farm is going to be connected to the system, the wind farm owner may not want to provide a detailed model due to proprietary concerns. This can delay the time required for performing the studies. The same situation can arise if more than one System Operators are stakeholders in the project.

2. During the preparation of the specification, it is essential that the relevant standards of all the stakeholders must be taken into account. This situation can arise if the HVDC link is connected to two different countries (e.g., Colombia and Panama). In some cases, the information from one stakeholder is delayed resulting in delayed specification completion date.

3. Once the specification is issued, the bidders are normally given 4 to 6 months to submit their bids. Depending on the market demand and the workload of the bidders, they may ask for more time to prepare their bids. In some cases, some bidders may even decide not to bid on the project due to various reasons. This may result in less than 3 bids for the project.

4. Approvals for overhead line construction or laying cables are increasingly difficult to obtain due to public concerns and major projects face long delays due to extended approval processes. Therefore, it is essential that the main stakeholders including the statutory authorities, the public and the landowners directly affected by the new overhead line/cable are consulted at a very early stage and continually kept up to date with progress. These issues could also result in delay of in-service date if not addressed properly.

5. There are number of HVDC systems already planned to be built in next few years. As a result, the HVDC cable manufacturers are very busy. This means that early discussions with manufacturers are necessary to ensure a cable manufacturing and laying slot is allotted. This could also result in delay of in-service date if not scheduled properly.

6. It is essential that the type of tests and number of tests to be performed during Factory Acceptance Tests (FAT) and the online commissioning tests at site must be agreed upon at least two months before the FAT starts. The bidder must finalize the control software and test the software before inviting the customer for witnessing factory tests.

7. The list of online tests, the test approval process and the outage requirements must be discussed and approved by the affected system operators at least three months ahead of time. The control software must be finalized with all the required modifications after FAT before the online testing starts. The controls should virtually require no changes during online testing.

5.3 Specific Challenges with the Under Sea HVDC Cables

The economic analysis showed that the HVDC transmission option with the submarine cable as the most expensive alternative.

As of today, the HVDC cable manufactures have a busy schedule. Specially considering the voltage rating of the cable, there will be only one or very few manufacturers capable of producing the cable. Therefore, the production timeline of the cable will be a determining factor in the project implementation.

The environment challenges related to the under sea cables are discussed in the report titled '*Environmental Issues Related to HVDC'* (report number: R1660.03).

5.4 Need for Additional Studies

The transient stability analysis (RMS simulation) tools such as DIgSLIENT have limitations when analysing modern power systems with significant amount of power electronic based devices. Systems with high amounts of inverter-based generation in weak AC grids require analysis using more accurate tools. The proposed renewable generation scheme is a unique case which needs special attention:

- There is a significant amount of renewable generation added in Collector 1.
- Collector 2 is a significantly weak system with 100% renewable generation and an HVDC rectifier.
- To maintain system stability, the HVDC rectifier should be operated in grid forming mode.

Considering these facts, it is recommended to perform a more detailed electromagnetic transient (EMT) simulation to verify the requirements defined for the following disturbances:

- AC system voltage performance for converter terminal AC faults
- Need for reactor cross tripping and verification of transient current rating of the converters for pole outages
- Need for generator and reactor cross tripping for bipole outage
- Outage of 500 kV line between Collector 1 and Collector 2 and the isolated operation of Collector 2.

In order to evaluate these requirements, a significant portion of the Colombian AC system needs to be modeled in an EMT software (e.g., PSCAD). At a minimum, the model should include: Collector 1 and Collector 2, AC lines parallel to the HVDC system and the major 500 kV buses. The renewable generation in Collector 1 and 2 should be modelled using a generic EMT model with sufficient detail (inverter and power plant controllers, FRT logics and basic protection logics). The VSC HVDC should also be modeled using a generic model with sufficient detail. It is recommended to perform this study before releasing the specification to the manufacturers.

5.5 Typical Studies Performed before Releasing the Specification

The requirements of the HVDC systems such as temporary overloads, special protection schemes, reactive power requirements and grid forming capability are already identified from the feasibility studies performed in this project. These requirements can be finetuned by performing the EMT studies described in Section 5.3. If UPME decides to move forward with a lower rating (e.g., 2500 MW), the critical contingencies evaluated in RMS simulations are required to be repeated to evaluate the impact.

In addition to these, the following studies are required to be performed before releasing the specification:

- Calculation of harmonic impedance sectors at the HVDC terminals
- Measurement of background harmonics at the HVDC terminals (AC substations)
- Insulation coordination of AC system (optional, can be done by HVDC manufacturer as well)
- Sub synchronous oscillation screening studies (to identify any devices in the system that can interact with HVDC).

6. Conclusions

This study identified the technical requirements and the high-level economic factors of the proposed 3000 MW HVDC bipole system to facilitate the integration of the renewable generation in the La Guajira area into the Colombian AC network. Two interconnection locations were evaluated:

- HVDC terminal at Cerromatoso
- HVDC terminal at Primavera

The steady state power flow analysis and the transient stability analysis were performed for study years 2028 (2000 MW transfer) and 2032 (3000 MW transfer) using DIgSLENT Powerfactory. The following conclusions are made:

Proposed technology

Considering the amount of renewable generation added and significantly weak AC network, it is recommended to consider the MMC VSC technology for this project. Based on the technical evaluation, the following features are required:

- Configuration: 3000 MW VSC HVDC bipole with the metallic return
- Converter configuration: Half bridge MMC converters with AC breakers (for DC fault clearing)
- Recommended DC Voltage Level: 600 kV
- Recommended interconnection option: DC overhead line from Collector 2 to Primavera
- Additional equipment: A DC chopper would be required to regulate the DC voltage during inverter side DC faults. Note that DC choppers are commonly used in VSC HVDC systems connected to offshore wind farms.
- Control philosophy:
    - Considering the significantly weak AC network at the rectifier (Collector 2), it is necessary to operate the HVDC rectifiers in grid forming mode. The studies have shown that the frequency droop-based grid forming technology would be sufficient.
    - The inverter is regulating the DC voltage. As described earlier, the DC chopper helps to regulate the DC voltage during inverter side AC faults.
    - Both rectifier and inverter can control the AC terminal voltage.
- Converter current rating: Considering the need of grid forming controls, a converter current rating of about 1.2 pu would be required. During the pole outage a short term transient current rating of about 1.3 pu for 1 to 2 seconds would be required. These requirements need to be verified using an EMT study (refer to the additional studies defined below).

AC system adjustments related to HVDC operation

- In order to maintain the uninterrupted power supply during a HVDC pole outage, a single circuit 500 kV AC connection between Collector 1 and Collector 2 is required. Under normal conditions, this line is very lightly loaded.

- A cross tripping scheme for the 500 kV AC line reactors should be implemented during the pole and bipole outages. The studies showed that the 500 kV system voltage significantly drops when a large amount of power is transferred from Collector 2 to Collector 1. The voltage profile improves significantly when the reactors are cross tripped.

  An alternative way of improving the transient voltage performance of the 500 kV parallel AC transmission network (instead of cross-tripping the reactors) is to install dynamic reactive power compensation devices such as STATCOM and SVC. It is recommended to perform a detailed study to evaluate the reactive power compensation in the AC system for different operating conditions including the heavy loading conditions during an HVDC pole outage.

Proposed HVDC terminal

- Considering the technical performance described below, Primavera has been identified as the best location for the HVDC terminal in the south.

Steady state system performance

The power flow analysis showed that the AC system losses are significantly lower for the option of HVDC terminal at Primavera. Although there are higher DC line losses for the Primevera option due to the longer DC line, there is less total loss when considering AC line loss because the load centers are closer to Primevera than Cerromatoso. The losses are compared in the following table.

Year	Study Case	AC system Losses without HVDC (MW)			HVDC system losses (MW)		
		Cerromatoso	Primavera	∆ AC Losses	Cerromatoso	Primavera	∆ DC Losses
2028	Min Dem Min Gen	158	153	5	67.2	72.6	-5.4
	Max Dem Max Gen	420	363	57			
2032	Min Dem Min Gen	206	187	19	101.4	113.4	-12
	Max Dem Max Gen	428	365	63			

The steady state contingency analysis (system intact and N-1) has shown that there are some AC system upgrades required to avoid overloads and voltage violation issues. Note that UPME has already identified some of the system upgrades. It was also observed that less upgrades are required for the option of HVDC terminal at Primavera. A summary table is provided below:

Equipment Overflow	VSC HVDC interconnection location	
	Cerromatoso	Primavera
Transmission lines		
Nueva Esperanza - Río 115 kV	Upgrade required	Upgrade required
Porce III - San Carlos 1 500	Upgrade required	-
Bacata - Suba 1 115	-	Upgrade required
Transformers		
Chinu 1 500/110 Chinu 2 500/110	Upgrade required	-

Equipment Overflow	VSC HVDC interconnection location	
	Cerromatoso	Primavera
Chinu 3 500/110		
La Virginia 500/230	Upgrade required	-

Transient stability performance

The transient stability analysis carried out for critical N-1 contingencies showed that the system performance meets the study criteria for both 2028 and 2032 study years. The performance criteria in the Colombian grid code defined for transient voltage and frequency recovery were fully satisfied. All the generators remained in synchronism. No load shedding was observed.

For the HVDC pole outages, it was necessary to have a short term transient current capability for the HVDC converters of about 1.3 pu for 1 to 2 seconds. Furthermore, it is required to cross-trip the 500 kV line reactors as described above. With these changes, the full amount of renewable generation in Collector 2 can be delivered without any interruption during a pole outage.

A Sensitivity analysis was performed to assess the system transient performance of the proposed interconnection option (VSC HVDC connected to Primavera) with the high renewable energy penetration in Sahagun area using the *Med Dem Max Gen* study cases for operational years 2028 and 2032. The transient stability analysis carried out for key contingencies showed that the system performance meets the study criteria for both 2028 and 2032 study years. Similar system performance and the requirements for the HVDC pole outage were also observed.

It is necessary to cross trip a large amount of renewable generation during a bipole outage. It is difficult to determine the exact amounts of generation trip at this stage due to the limitations in RMS simulation tools. An accurate estimation can be determined during the design stage using EMT simulations.

In general, the electromechanical oscillations of the system are well damped and there is no concern about the small signal stability. The grid forming control concept of the HVDC worked well and no adverse interactions with the AC system was observed.

High level cost comparison

A high-level economic analysis was performed to evaluate the interconnection options: 1- DC overhead line to Cerromatoso, 2- DC overhead line to Primevera and 3- DC cable + overhead line to Cerromatoso. A summary of the cost comparison is provided below. The analysis showed that the Option 2- DC overhead line to Primevera is the most economical interconnection option.

Option	Description	Cost of Converter (Mil USD)	Cost of Line+Cable (Mil USD)	Cost of ROW (Mil USD)	Cost of Losses (Mil USD)	Total Cost (Mil USD)
1	Overhead line to Cerromotoso	1275	214.5	65	730	2285
2	Overhead line to Primavera	1275	257.4	78	521.3	2132
3	Overhead+submarine to Cerromatoso	1275	1846	15.1	916.5	4053

Recommendations

Additional studies

Considering the complexity of the project, involvement of large amount of power electronic based devices (wind, solar, HVDC etc.) and the weak AC connection at the rectifier, it is recommended to perform an additional electromagnetic transient (EMT) study to verify the specific requirements and modifications identified for the HVDC system and the AC network. This needs to be carried out before releasing the specification. The modelling details and the cases to be considered are summarized in this report (Section 5.4).

The studies found that it is necessary to cross trip the 500 kV line reactors after an HVDC pole outage in order to maintain the voltage stability of the system. Alternatively, dynamic reactive power compensation devices such as STATCOMs and SVCs may produce the required support. It is recommended to perform a detailed study to evaluate the reactive power compensation in the AC system for different operating conditions including the heavy loading conditions during an HVDC pole outage.

Project Implementation Aspects

The requirements of this project (MW rating and DC voltage rating) are pushing the available VSC HVDC technology to its limits. The 3000 MW rating for a VSC bipole is only available in China and the most common rating in the rest of the world is about 2000 MW. The most common DC voltage that can be used for both overhead and cable transmission is 525 kV. Our inquiries with the manufacturers have revealed that 3000 MW rating at 600 kV is still achievable but the cost would be high. If it is necessary to have a 600 kV DC cable section, only few manufacturers have the capability. Therefore, considering these facts, UPME may consider a lower rating for this project. An HVDC of 2000 or 2500 MW at 525 kV can be achieved using commonly available technology at present.

TGS also recommends the consultation with HVDC vendors to determine the feasibility, alternatives, and the economic impact of the project.

7. References

[1] UPME, "PLAN DE EXPANSIÓN DE REFERENCIA GENERACIÓN – TRANSMISIÓN 2017 – 2031," Ministerio de Minas y Energía, Colombia, 2018.

[2] Transgrid Solutions Inc., "Task 1 – Selection of HVDC or HVAC Transmission, HVDC Transmission Assessment for Expansion of Renewable Energy in La Guajira, Colombia," WORLD BANK, 2022.

[3] UPME, "PLAN DE EXPANSIÓN DE REFERENCIA GENERACIÓN - TRANSMISIÓN 2020 – 2034," Ministerio de Minas y Energía, Colombia.

[4] EPRI, "Technical and Economic Comparison of HVDC LCC and VSC Technologies," Palo Alto, CA, 2021.

[5] CIGRE, B4.46, "Voltage Source Converter (VSC) HVDC for Power Transmission – Economic Aspects and Comparison with other AC and DC Technologies," April 2012.

[6] UPME, "PLAN DE EXPANSIÓN DE REFERENCIA GENERACIÓN – TRANSMISIÓN 2015 – 2029," Ministerio de Minas y Energía, Colombia.

Appendix A. DigSILENT DB Model Adjustments

The performance evaluation of the DigSILENT database carried out throughout the project resulted in several updates to the system model.

A.1 Changes proposed by UPME

- Voltage measurement point of the dynamic devise model of the Solar Bolivar generator was changed to Bolivar\Solar Bolivar LV 0.63kV\Cub Gen
- The Following changes were performed for the plants Gen Solar Bolivar 8.185 MW, Gen Solar Ocaita 9.9 MW and Solar Espinal 9.9MW:
    - Initially the controllers were enabled for all plants
    - The PQ Measurement_int, Voltage Measurement_int and PLL meters were set measure the connected low voltage level bus bar cubical oriented towards the generator
    - PQ Measurement, Voltage Measurement, Current Measurement and Frequency Measurement meters were set to measure the high voltage level bus bar cubicle oriented towards the high voltage side of the transformer
    - The PQ Measurement and PQ Measurement_int meters were set to consider the total apparent power of the plant as the base
- The Following changes were performed for the plants Apotolorru 75MW, Carrizal 195MW, Casa Electrica 180MW, EO200i 201MW, Gen Solar El Carmelo 9.9 MW, Irraipa 99MW, Kuisa 200MW, Urraichi 100MW:
    - The PQ Measurement and PQ Measurement_int meters were set to consider the total apparent power of the plant as the base
- The tie-line to Ecuador was disabled for this study (The tie-line was very lightly loaded in the study cases considered for this study)

A.2 Renewable generator model updates

Following updated parameters were used for the PQ control (Table A-1) and the plant control models (Table A-2) in the renewable generator models.

Table A-1 Updated parameters: PQ Control

Parameter	Value	Parameter	Value
PfFlag	0	Kqv	4
Thdl	0	Vdip	0.85

Parameter	Value	Parameter	Value
Iqfrz	0	Vup	2
VFlag	1	Tiq	0.05
dPmax	0.45	Tpord	0.05
dPmin	-0.45	Thdl2	0
step	0.001	Imax	1.1
Tp	0.05	PqFlag	1
Kqp	0.2	Qmin	-0.5
Kqi	0.6	Vmin	0.9
Kvp	0	Iql1	-1
Kvi	40	Pmin	0.04
QFlag	1	Qmax	0.5
Trv	0.01	Vmax	1.1
db1	-0.1	Iqh1	1
db2	0.1	Pmax	1.05

Table A-2 Updated parameters: Plant Control

Parameter	Value	Parameter	Value
Rc	0	Vfrz	0.7
Xc	0.02	Tp	0.05
Planta	1	Kpg	1
Kc	0	Kig	1
VcompFlag	0	Tlag	0.02
Tfltr1	0.02	ON_OFF_LIMITE	1
Tfltr2	0.02	fact	0.9975
Freq_ref	1	Freq_flag	0
Ddn	6	Estatismo	25
Dup	6	selectEst	1
fdbd1	-0.0005	emin	-99
fdbd2	0.0005	Qmin	-0.3
RefFlag	1	femin	-99
dbd	0	Pmin	0
Kp	1	emax	99
Ki	2	Qmax	0.3
Tft	0	femax	99
Tfv	0.01	Pmax	1

A.3 Other modifications

- Representation of Sahawind 200 MW renewable energy plant in RMS simulations

  A similar dynamic model to the Kuisa 200 MW renewable energy plant was assigned to represent the Sahawind 200 MW generation

Appendix B. Detailed Simulation Results—Steady State Analysis

Appendix C. Detailed Simulation Results—Transient Stability Study

Appendix D. Detailed Simulation Results—Transient Stability Study—VSC HVDC Pole Outage with 1.3 pu Converter Current Rating and Reactor Cross-tripping