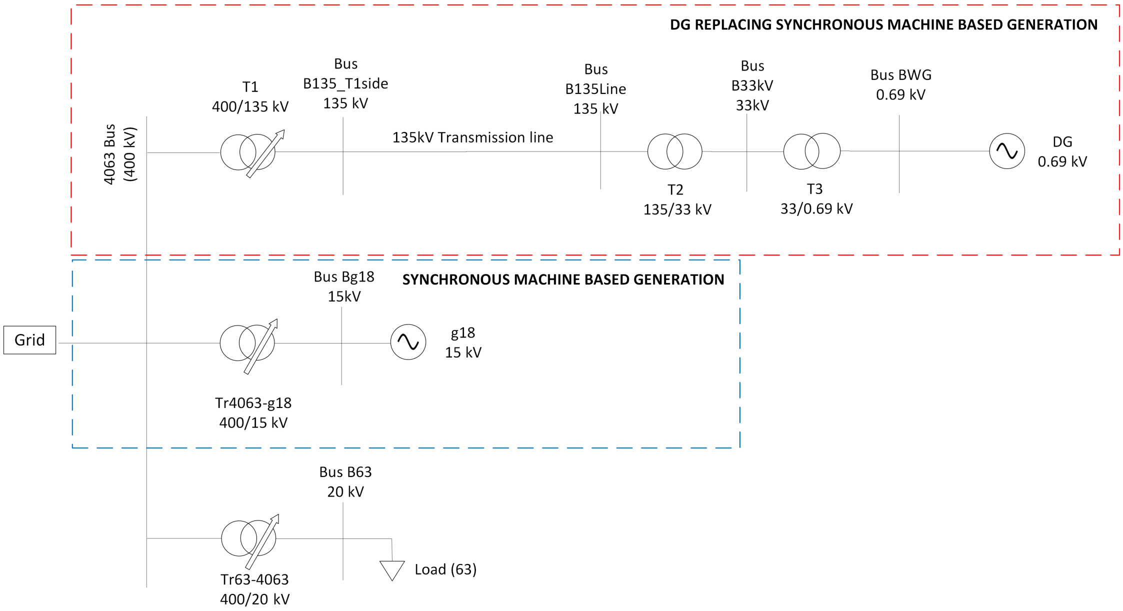

Voltage Stability Assessment of System with High share of Inverter Interfaced Generation

Long Term Voltage Stability Assessment using DIgSILENT Powerfactory simulations

Master's thesis in Sustainable Electric Power Engineering and Electromobility

AMUTHAVALLI JOTHIRAM

DIVISION OF ELECTRIC POWER ENGINEERING

CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2025
www.chalmers.se

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Supervisor: Peiyuan Chen, Assistant Professor, Division of Electrical Engineering
Examiner: Peiyuan Chen, Assistant Professor, Division of Electrical Engineering

Master's Thesis 2025
Division of Electrical Engineering
Chalmers University of Technology
SE-412 96 Gothenburg
Telephone +46 31 772 1000

Cover: P-V curves at 400 kV bus (4041) of Central Sweden in the case of replacing one of the Synchronous Generators at South Sweden with DG

Typeset in LaTeX
Printed by Chalmers Reproservice
Gothenburg, Sweden 2025

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Abstract

A significant amount of renewable energy-based generators are being connected to the distribution grid and provide reactive power support to the transmission grid in a less effective way compared to traditional centralized synchronous machine-based generation. Consequently, the voltage stability phenomenon is affected in the transmission buses. In this Master thesis, the impact of distributed generation (DG) on voltage stability at the transmission grid is studied. The analyses are done in a simplified two-bus system and in the IEEE/CIGRE Nordic32 benchmark model using DigSILENT PowerFactory simulations. The impact on the PV curves of the transmission buses has been evaluated considering different control modes of DGs at different control points. One of the synchronous generators in South Sweden is replaced by DG, and its impact on the maximum power transfer from North to Central Sweden has been studied. Furthermore, the loss of one transmission line between North and Central Sweden has also been studied.
When one of the synchronous generators is replaced by DG in South Sweden, the control of the voltage at the DG terminal causes a reduction in transfer capacity compared to the current scenario of the synchronous generator. This is caused by an increase in impedance between the DG and the TSO bus. With voltage control at the 135 kV bus to 1 p.u., the transfer capacity is worse than the voltage control in the DG terminal scenario. DG tries to keep the voltage to 1 p.u. at the 135 kV bus by supplying Q appropriately, causing more reactive power demand compared to DG voltage control at its terminal. So, DG reaches its Q limit earlier. This results in reduced transfer capacity. In contrast, with Q control on the 135 kV bus, it is observed that the reactive power of the DG is not fully utilized, as the transfer capacity reaches its limit even before the reactive power limit of the DG is reached.

Keywords: Long-term voltage stability, Renewable energy integration, PV curve, PowerFactory simulation.

Acknowledgements

I express my gratitude to my supervisor Peiyuan Chen for his excellent guidance to do this Master thesis work. I thank my family for their kind support to finish this thesis work.

Amuthavalli Jothiram, Gothenburg, June 2025

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis listed in alphabetical order:

IBG	Inverter Based Generation
DER	Distributed Energy Resource
DG	Distributed Generation
DSO	Distribution System Operator
PV	Photovoltaic
TSO	Transmission System Operator
Q	Reactive Power

Nomenclature

Below is the nomenclature of indices, sets, parameters, and variables that have been used throughout this thesis.

Indices

P_{max}	Maximum power transfer limit in the 400 kV bus
Q_{min}	Minimum Reactive power limit of generators
Q_{max}	Maxmum Reactive power limit of generators

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1 Introduction

Renewable Energy sources such as wind and solar are increasingly deployed in the place of traditional synchronous machines that uses fossil fuels as a measure towards a sustainable energy solution. Renewable energy sources such as wind and solar are either connected to transmission grid or directly connected to the distribution grid based on their location and installed capacity. Also they have power electronic interfaced converters to connect to the grid, which has limited over current capability due to their construction. This interconnection of Inverter Based Generation (IBG) to distribution grids exhibits different behaviour during voltage contingency events with the possibility of different control modes.
In this thesis work, voltage stability criteria during different generation mix scenarios are studied using DIgSILENT Powerfactory simulations.

1.1 Background

The Swedish power system has more hydro plants at Northern part. More power is transmitted from North to Central Sweden. In this thesis work, voltage stability assessment is carried out in the Central Sweden for replacing some of the synchronous generator with large wind farms in South Sweden. Different control methodologies such as voltage and reactive power control from DG while integrating them to the distribution grid has also been studied in this thesis work.

1.2 Project Scope

Scope of this thesis work is limited to DIgSILENT PowerFactory simulations for Nordic-32 test system to perform Long-Term Voltage Stability Assessment. Voltage stability is assessed for gradual increase in load conditions. Impact of the loss of one transmission line from North to Central Sweden on its voltage stability is also studied.

1.3 Project Objectives

Main goal of this thesis work is to reassess the voltage stability at 400 kV buses in the Central Sweden of the Nordic-32 model when some of the synchronous generators at South Sweden are replaced by DG. In order to do that, different generation mix scenarios created in the Nordic-32 model using DIgSILENT Powerfactory tool. Driving factors for voltage stability are to be evaluated. Mitigation measures to improve the voltage stability in future generation mix scenarios are to be assessed. Reactive power capability limits of DG are to be modeled accordingly.

1.4 Methodologies

First, PV curve analysis for a simple 2-bus system is simulated in MATLAB to verify the theoretical results. A simple MATLAB script is run to verify the critical demand (P_{max}) and the voltage at critical demand (V at P_{max}) beyond which the system voltage collapses. Furthermore, voltage at different load conditions are plotted (P-V curve).
Second, a similar system is implemented in Powerfactory simulation tool to analyze voltage stability of the system. Further, the model is extended for different generation mix scenarios such as adding a synchronous condenser, adding a synchronous machine-based generation and replacing synchronous machine based generation with distributed generation (DG).
Finally, voltage stability of the Nordic-32 system is re-assessed in Powerfactory where traditional generation at the southern region of the system is replaced with DG.

1.5 Report Structure

This thesis report is structured as follows:

- Chapter 2 reviews the theory needed for the thesis work
- Chapter 3 gives the voltage stability assessment on a simple network implemented in DigSILENT power factory to understand the concepts of different control methodologies during DG integration and mitigation measures to improve the PV curves during those cases
- Chapter 4 provides the voltage stability assessment of Nordic-32 model for different generation mix scenarios
- Chapter 5 gives the discussion about the results obtained through simulation on generation mix scenarios of Nordic-32 model
- Chapter 6 provides the conclusion and future works.

2

Theory on Voltage Stability and Reactive Compensation

Voltage stability is a phenomenon where the power system maintains its voltage level within acceptable limits for increase in load active power demand. Voltage collapse is the process when the unstable system voltage experiences uncontrolled reduction in voltage[1]. The reactive power support in the system determines the active power transfer from the generation terminal to load area. When there is not enough reactive power support available in the power system, the power system may not be able to maintain the voltage as per grid code and eventually voltage collapse may occur.

2.1 Classification of Voltage Stability

Voltage stability can be classified based on the size of disturbance and time frame of interest into the following categories [2]:

2.1.1 Based on disturbance size

Based on the size of the disturbance, voltage stability can be classified into two categories:

Large-disturbance voltage stability

This refers to the ability of the system to maintain steady voltages following a large disturbance such as loss of generation, system faults etc. The study period of interest is between a few seconds to tens of minutes.

Small-disturbance voltage stability

This refers to the ability of the system to maintain steady voltage for small perturbations such as gradual load increase in the system. This type of stability is affected by load characteristics and control methodologies of the system.

2.1.2 Based on time frame of interest

Based on the time frame of interest, voltage stability can be classified into two types:

Short-term voltage stability

Short term voltage stability is assessed with dynamics of fast acting load components such as induction motors, power electronic interfaced loads and HVDC converters using differential equations. The analysis is made in the order of few seconds.

Long-term voltage stability

Long term voltage stability involves slower acting equipments e.g., tap changing transformers and generator armature and field current limiters. The study period of interest can be several minutes. Stability is determined by the resulting outage of equipment. Instability may occur when loads try to restore their power more than the available generation in the system or transfer capacity of the network.

2.2 P-V curve analysis

The relation between load active power demand and voltage at load bus is given by P-V curve analysis. To understand this, let us consider a simple 2 bus system as shown in figure 2.1. The key parameters of the elements in the 2-bus system is shown in Table 2.1.

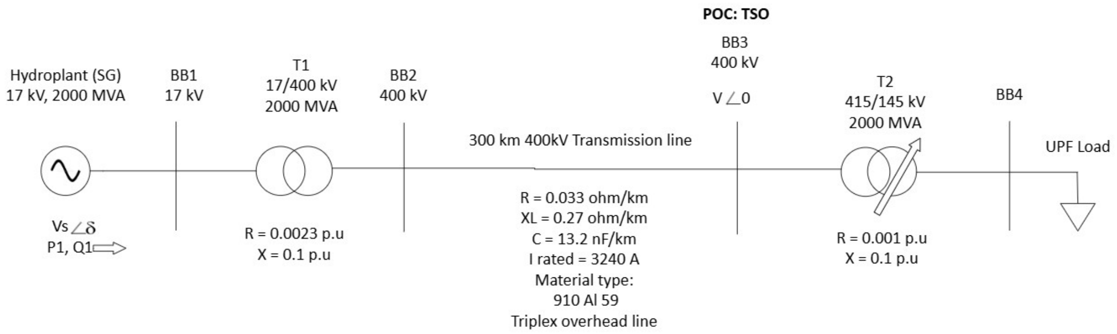

Figure 2.1: Simple 2-bus system for P-V analysis

Table 2.1: Parameters of network elements in base scenario

Element	Parameters
Hydroplant (SG)	17 kV, 2000 MVA
T1 transformer	17/400 kV, 2000 MVA, R = 0.0023 p.u., X = 0.1 p.u.
400 kV Transmission line	Line type: 910 Al 59, triplex core, R at 20C: 0.033 Ω/km, Series reactance: 0.27 Ω/km, Capacitance: 13.2 nF/km, Rated current: 3240 A, Line length: 300 km
T2 transformer	400/145 kV, 2000 MVA
UPF load	2000 MW

Step 1: Calculation of P_{max}

For the given system, total impedance in p.u is calculated to j 1.1956 p.u. For simplification, lumped parameter model was used in 400 kV line modeling and shunt admittance

ignored. Detailed calculation is given in appendix A
Assuming that the sending end voltage at bus B1 is controlled to 1 p.u, the maximum active power that can be transferred to load bus can be calculated as follows [3].

$$P_{max} = \frac{1}{X} \cdot \sqrt{\frac{V_1^4}{4} - X \cdot V_1^2 \cdot Q}$$

$$Since Q = 0 \; for \; Unity \; PF \; load$$

$$\begin{aligned} P_{max} &= \frac{1}{X} \cdot \sqrt{\frac{V_1^4}{4}} \\ &= \frac{1}{1.1956} \cdot \sqrt{\frac{1^4}{4}} \\ &= 0.41825 p.u \; or \; 836.4 \; MW \end{aligned}$$

Step 2: Plotting PV curve

Voltage at the load bus can be obtained using the relation below[3].

$$V = \sqrt{\frac{V_1^2}{2} - Q_L \cdot X \pm \sqrt{\frac{V_1^4}{4} - X^2 \cdot P^2 - X \cdot V_1^2 \cdot Q_L}} \tag{2.1}$$

PV curve was plotted based on the equation 2.1. The load bus voltage with respect to load active power sweeped in the range of 0 to P_{max} calculated in the previous section, the PV curve at the TSO bus BB3 is shown in figure 2.2 as solid line.

2.3 Impact of Synchronous Condenser as Shunt Compensation

A synchronous condenser can be operated in constant Q control mode, through which a constant reactive power can be either supplied to or absorbed from the load bus to which it is connected [5]. Two cases considered:

- 200 MVAr injection
- 200 MVAr absorption

The PV curves thus obtained are shown in figure 2.2 with the dashed line corresponds to 200 MVAr injection and dash-dotted line corresponds to 200 MVAr absorption. From the PV curve analysis, it can be observed that injection of reactive power by a synchronous condenser increases the maximum active power limit that can be transferred through the network to 1016.9 MW with an increase of 180.5 MW compared to no compensation case. But it also causes some over voltage at low active power demand. When subtracting Q_C of synchronous condenser from load reactive power Q_L, from equation 2.2, the stable operating region is extended or reduced based on injection of absorption of Q from synchronous condenser.

$$V = \sqrt{\frac{V_1^2}{2} - (Q_L - Q_C) \cdot X \pm \sqrt{\frac{V_1^4}{4} - X^2P^2 - XV_1^2(Q_L - Q_C)}} \tag{2.2}$$

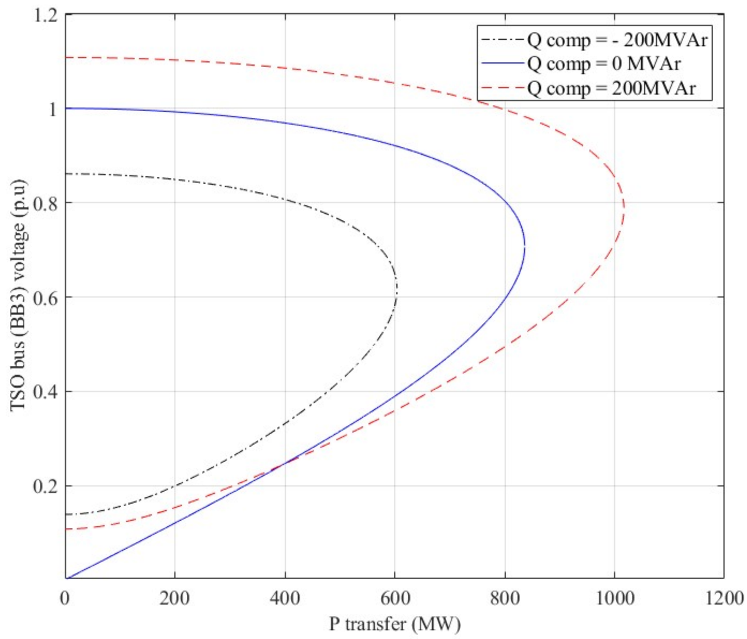

Figure 2.2: PV curve of the system with Q compensation from a synchronous condenser

2.4 Impact of Static Capacitor as Shunt Compensation

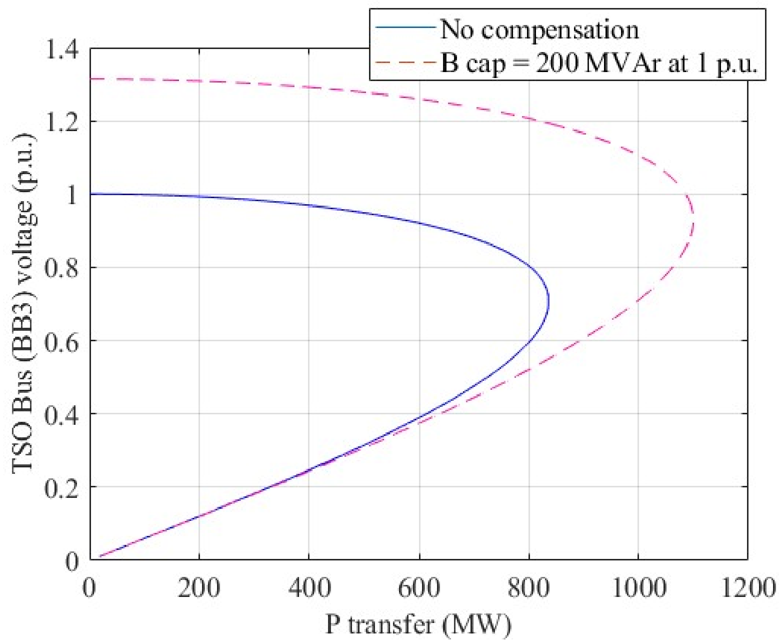

Figure 2.3: PV curve of the system with Q compensation from a static capacitor

While adding a static capacitor for reactive power support at load bus, it exhibits a different behaviour compared to synchronous condenser. Since the reactive power supplied

by the capacitor depends on the voltage across its terminals, at high voltages it provides more Q support, but when the network voltage drops, Q support by capacitor is inversely proportional to square of the operating voltage. Due to this fact, adding a static capacitor for Q compensation involves over voltage at low load conditions. In Figure 2.3, solid line corresponds to no compensation case and dashed line corresponds to 200 MVAr shunt compensation with a static capacitor. Compared to the PV curve obtained for compensation from synchronous condenser, it can be noted that shunt compensation by static capacitor of same size (200 MVAr) has high voltage at low load conditions.
The maximum power transfer while adding a shunt capacitor or a synchronous condenser along with the resistive load under consideration is given by the following equation [3].

$$P_{max} = \frac{E^2}{2X}\frac{\cos\theta}{1+\sin\theta} \tag{2.3}$$

It can be seen that in the case of shunt capacitor, the capacitive power factor is constant throughout the operation. At 1 p.u. operation voltage, as per 2.3 the maximum power transfer is calculated.
In the case of synchronous condenser, the amount of reactive power injected or absorbed into the system is given by the voltage difference between the grid voltage (V) and the synchronous condenser terminal voltage (E).

$$\begin{aligned} I &= \frac{V-E}{X} \\ Q &= V \cdot I = \frac{1-\frac{E}{V}}{X} \cdot V^2 \end{aligned} \tag{2.4}$$

When the system voltage is 1 p.u., synchronous condenser does not inject any reactive power into the system, in contrast to shunt capacitor that injects its entire capacity into the system at 1 p.u., system voltage. Near the maximum P transfer points, Q support from static capacitor is more compared to synchronous condenser. Due to this. P_{max} is higher in the case of shunt capacitor than synchronous condenser. The P_{max} limit in the two Q compensation methods are shown in Table 2.2

Table 2.2: Comparison of P_{max} with 200 MVAr Q compensation using a synchronous condenser and static capacitor

	$P_{max}(MW)$	Increase in $P_{max}(MW)$
200 MVAr Synchronous condenser	1016.9	180.2
200 MVAr Static capacitor	1099.1	262.7

3

P-V Analysis for Generation mix scenarios of a simple system using DIgSILENT Powerfactory

In the previous chapter, P-V analysis of a simple 2-bus system shown in Figure 2.1 performed using MATLAB was discussed. In this chapter, P-V analysis of the similar system with the same network parameters listed in Table 2.1 performed using DIgSILENT PowerFactory tool is discussed. Later different generation mix scenarios and how to improve the P transfer limit in the 400 kV line in each scenario are discussed.

The following scenarios are discussed in this chapter:

- Scenario 1 (base scenario): Simple 2 bus system.
- Scenario 2: Improving P transfer limit by adding synchronous machines in the transmission grid (TSO bus BB3)
  - as a synchronous condenser
  - as a synchronous generator
- Scenario 3: Improving P transfer limit by adding DG in the distribution grid with different control modes
  - voltage control mode at DG terminal, 33 kV bus (BB7), 135 kV bus (BB6) and 400 kV bus (BB3)
  - Q control mode at 135 kV bus (BB6)

3.1 Base scenario

The P-V analysis in the base scenario shown in Figure 2.1 was performed using PowerFactory tool. Since the simulation software runs the analysis up to the critical scalable demand, only the upper part (stable voltage region) of the P-V curve is obtained as shown in Figure 3.1.
At no load condition, due to Ferranti effect over voltage (1.06381 p.u) is observed at the receiving end of the transmission line, i.e., the overhead line injects more reactive power than it consumes. As the load increases, load voltage drops as shown in the figure 3.1. P_{max} and $V_{P_{max}}$at BB3 (TSO bus)are given in Table 3.1:

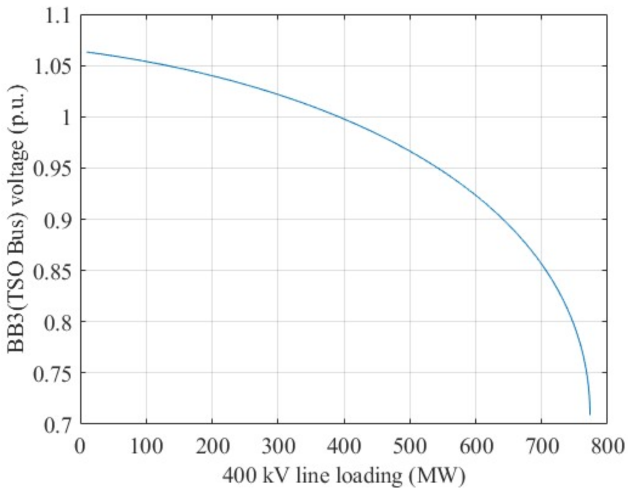

Figure 3.1: P-V curve for base scenario using powerfactory tool

Table 3.1: P_{max} and V at P_{max} in the P-V curve for the 2 bus system.

P_{max} (MW)	773.35
$V@P_{max}$ (p.u.)	0.711

3.1.1 Comparison of P-V curve obtained in MATLAB and DIgSILENT Powerfactory tools

Comparing the PowerFactory result with the MATLAB result shown in Figure 2.2, there is a difference in the P transfer limits as mentioned in Table 3.2. Since distributed parameter model chosen for 400 kV line in the PowerFactory software, it produces more accurate results.

Table 3.2: Comparison of P_{max} for 2-bus system using MATLAB and DIgSILENT PowerFactory tools

	P_{max} (MW)	V @ P_{max} (p.u.)
Matlab simulation	836.4	0.705
Powerfactory simulation	773.35	0.711

3.2 Improving 400 kV transmission line transfer capacity and voltage by adding synchronous machines in transmission grid

Synchronous machine can produce and absorb reactive power based on the network conditions to regulate the bus voltage where it is connected. In this section, two cases are discussed:

1. Improving BB3 (TSO bus) voltage and 400 kV line P transfer capacity by adding a synchronous condenser
2. Improving BB3 (TSO bus) voltage and 400 kV line P transfer capacity by adding a synchronous generator

3.2.1 Modeling synchronous machine in powerfactory

In PowerFactory, a synchronous generator was added to the transmission grid via a step up transformer T3. The network parameters are given in Table 3.3. The implementation is shown in Figure 3.2. The same machine was used as a synchronous condenser by making its active power output to zero. The Q operational limits were set to $\pm 0.5 P_{max}$. Voltage at the synchronous machine is controlled to 1 p.u. throughout the simulation.

Table 3.3: Parameters of network elements in synchronous generator scenario

Element	Parameters
Synchronous generator	17 kV, 2000 MVA, 0.9 powerfactor, Q limit ±500 MVAr
T3 transformer	400/17 kV, 2000 MVA, R = 0.0023 p.u., X = 0.1 p.u.

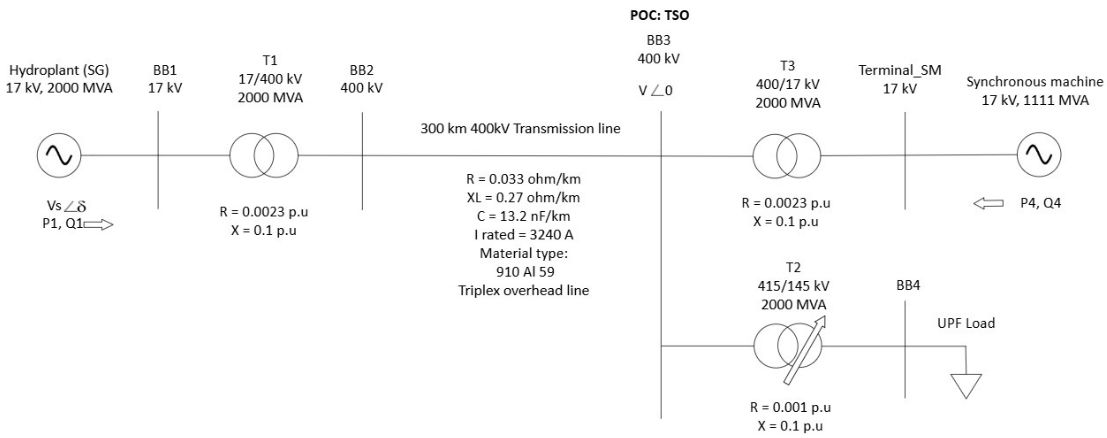

Figure 3.2: Improving P transfer limit by adding synchronous machine to base scenario

3.2.2 Effect of adding Q support from a synchronous condenser

To increase the P transfer limit in the 400 kV line, a synchronous condenser can be added as shunt compensation at the BB3 (TSO bus). Voltage at the BB3 (TSO bus) can be controlled by controlling reactive power at that terminal either by injecting (at low voltage conditions) or absorbing (at high voltage conditions). This is illustrated in figure 3.3. Solid curve shows the P-V curve in base scenario. Dashed curve shows the P-V curve in synchronous condenser case. The size of the synchronous condenser is 500 MVAr. Dash-dotted curve gives the amount of Q produced or absorbed from synchronous condenser.

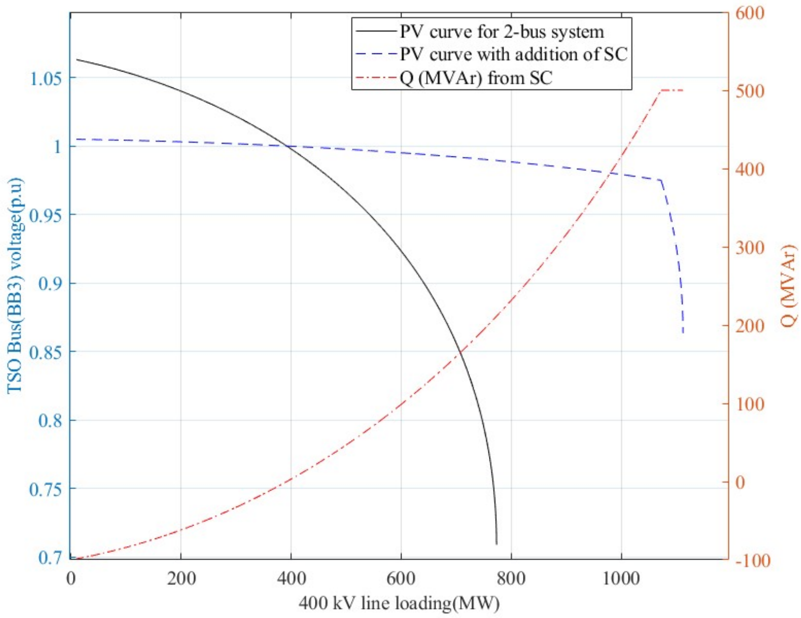

Figure 3.3: Improving voltage profile of a 2-bus system by providing Q support from a synchronous condenser

Analysis of P-V curve in synchronous condenser case

From the P-V curve of synchronous condenser case shown in Figure 3.3, the following observations are made:

- At minimum load condition, synchronous condenser absorbs 98.77 MVAr. In Base scenario, the voltage at BB3 bus was 1.063 p.u. By absorbing the Q generated by 400 kV line with the synchronous condenser, BB3 bus voltage is brought to 1.005 p.u. Synchronous condenser operates in under excited condition. It is to be noted that the synchronous condenser terminal is controlled to 1 p.u.
- Figure 3.4 shows that Q flow into BB3 bus from 400 kV line is compensated by synchronous condenser. In addition to that, synchronous condenser also supplies reactive power to T2 and T3 transformers for their operation. The difference in Q observed at heavy load conditions in Figure 3.4 is caused by the Q losses in these transformers.
- When the P transfer is 389.91 MW, BB3 bus voltage reaches 1 p.u. Since synchronous condenser produces or absorbs reactive power only when there is a difference in POC voltage and its terminal voltage, Q from synchronous condenser is zero at this point.
- When the P transfer in the line is 773.37 MW, Q from SC is 220.47 MVAr. Figure 3.3 shows that P_{max} limit was reached in base scenario at this level. But in synchronous condenser case, the Q limit of synchronous condenser was not reached yet. So the P transfer can be increased further without causing system voltage collapse.
- When P transfer was 1073.78 MW, synchronous condenser reached its Q limit. After this point, BB3 bus voltage starts to fall.

- P transfer limit was increased to 1112.4 MW after which system lost its stability.

The P-V curve data are given in Table 3.4. For the same level of P transfer, BB3 bus voltage in base scenario is given in brackets. It can be seen that voltage at BB3 bus has been stabilized with the reactive power support from synchronous condenser.

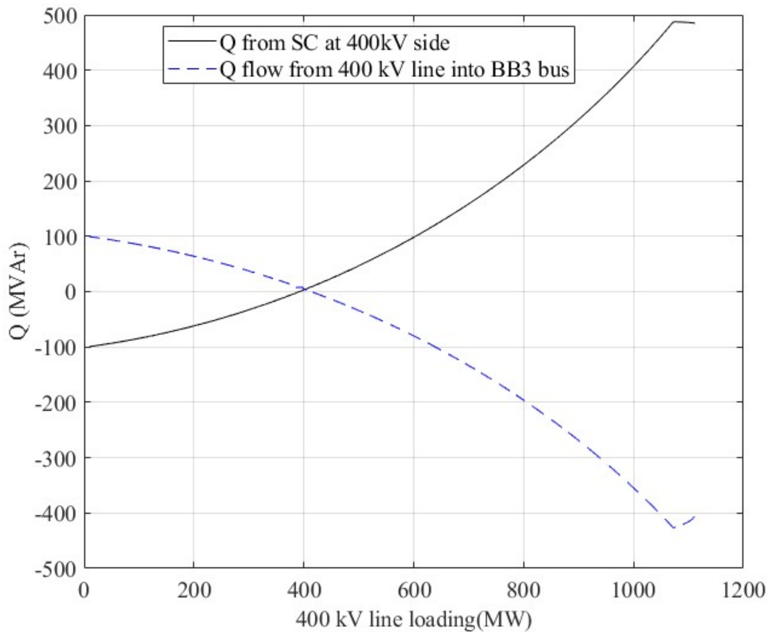

Figure 3.4: Q from synchronous condenser vs Q flow from 400 kV line into BB3 (TSO bus) BB3

Table 3.4: Significant points in the P-V curve for the 2-bus system with Q compensation from synchronous condenser. TSO bus voltage shown in bracket corresponding to base scenario for the same P transfer

P transfer (MW)	TSO bus voltage (p.u.)	Q from SC (MVAr)
9.51	1.005 (1.063)	-98.77
389.91	1(1)	-0.73
773.37	0.989(0.709)	220.47
1073.78	0.975	500
1112.4	0.864	500

Synchronous condenser regulated BB3 bus voltage to 1 p.u. by appropriately absorbing reactive power at low load conditions and supplying reactive power when the load increases i.e., when BB3 bus voltage falls below 1 p.u. Also the maximum power transfer limit was increased to 1112.4 MW. Comparision of maximum power transfer limit through the 400 kV line for base scenario and adding synchronous condenser to transmission grid is given in Table 3.5. The maximum power transfer in the 400 kV line has been increased by 339.47 MW (43.9%) by adding a synchronous condenser to the BB3 (TSO bus) for reactive power support. Also the voltage at maximum power transfer point is improved to 0.864 p.u.

Table 3.5: Comparision of Maximum power transfer limits for base scenario and adding a 500 MVAr synchronous condenser

	Base scenario	Adding a synchronous condenser	Increase
P_{max} (MW)	772.928	1112.4	339.47 (43.9%)

3.2.3 Effect of adding a synchronous generator at the load side

The synchronous machine shown in Figure 3.2 was used as a synchronous generator with 1000 MW active power generation with voltage control at its terminal set to 1 p.u.. The Q limit was set to $\pm 0.5 P_{max}$ of the generator, which corresponds to ±500 MVAr. Figure 3.5 shows the BB3 bus voltage vs 400 kV line loading curves for the base scenario (solid curve) and addition of synchronous generator scenario (dashed curve). The dash-dotted curve shows the Q from synchronous generator at different voltage levels of the TSO bus BB3.

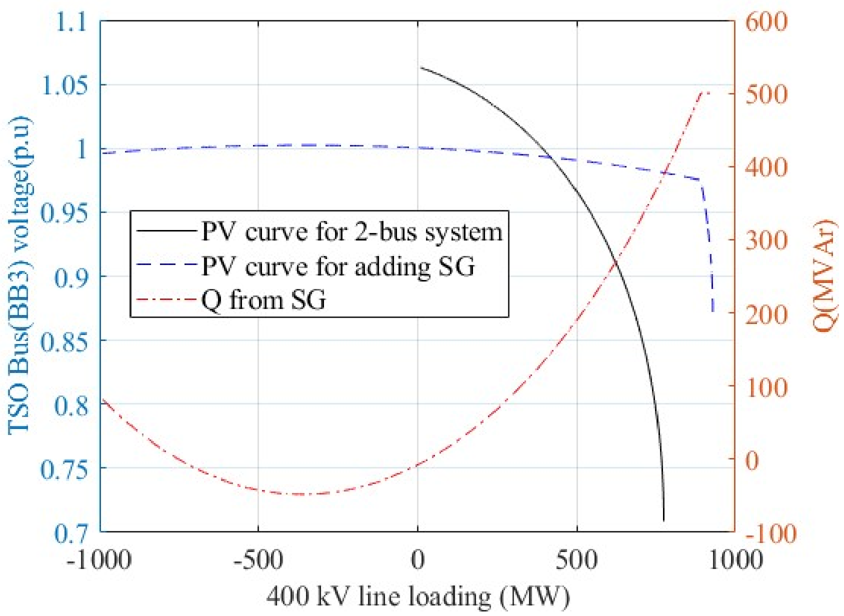

Figure 3.5: PV curve at TSO bus BB3 for base scenario vs adding a synchronous generator scenarios

Analysis of P-V curve in synchronous generator case

- As the synchronous generator was considered with V control at its terminal, it produces 1000 MW active power at 1 p.u terminal voltage irrespective of the load demand. At low load conditions, the excessive power produced by the synchronous generator is transferred to external grid.
- From the figure 3.5 it can be seen that at no load condition, synchronous generator injects 81.5 MVAr into the system to enable TSO bus send 1000 MW production towards external grid. At low load conditions, more power is transferred to grid. Since active power flowing through the line is high, 400 kV line becomes inductive and requires Q from synchronous generator. Figure 3.6 shows synchronous

generator supplies or absorbs Q according to Q flow into BB3 bus by the 400 kV line. In addition to that, synchronous generator supplies Q required by T2 and T3 transformers.

- Since the synchronous generator terminal is controlled to 1 p.u using voltage control mode, TSO bus (BB3) voltage becomes slightly less than 1 p.u. (0.996 p.u.) at minimum load condition.
- As the load active power demand increases, synchronous generator starts to supply the local load, consequently power flow in 400 kV line towards grid is reduced. This results is decreased Q consumption by 400 kV line. The minimum point in the Q support plot is -47.9 MVAr corresponding to 360.76 MW active power flow in the transmission line towards the main grid. This implies that the transmission line becomes capacitive due to its light loading.
- When the P transfer from grid to load becomes 33.82 MW, TSO bus (BB3) voltage becomes 1 p.u. At this point, Q produced by the 400 kV line is equal to Q losses in T2 and T3 transformers. Synchronous generator Q output becomes zero.
- When the line loading is 773.37 MW, system stability was lost in base scenario. But when adding synchronous generator to the transmission grid, system voltage is stable (0.981 p.u.) as synchronous generator supplies 389.18 MVAr into BB3 bus, preventing voltage collapse.
- When the P transfer becomes 889.7 MW, synchronous generator hits its Q limit of 500 MVAr. Voltage at TSO bus (BB3) becomes 0.975 p.u. After this point, voltage falls rapidly and collapses when the P transfer limit is reached. P transfer at critical scalable demand point is 912.83 MW. Voltage at collapse point is 0.937 p.u.

The key points of Figure 3.5 are listed below in Table 3.6.

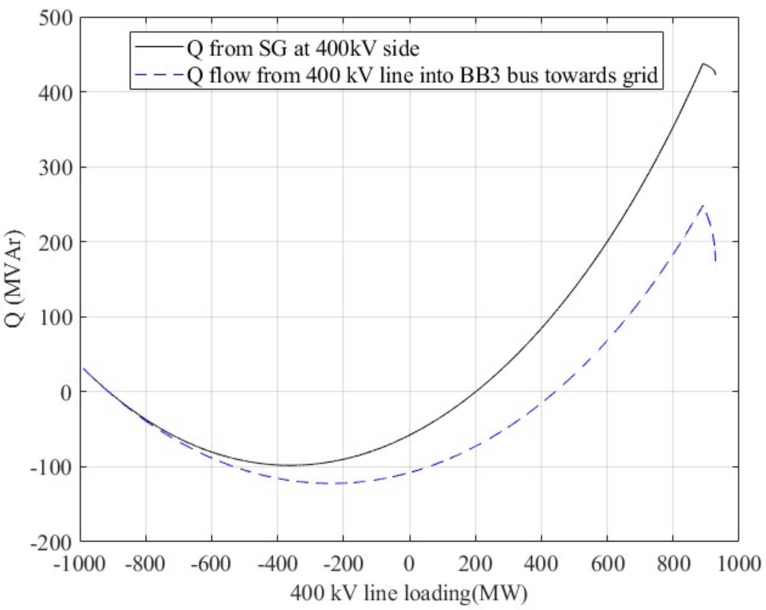

Figure 3.6: Q from 400 kV line into BB3 bus towards grid vs Q from synchronous generator

Table 3.6: Significant points in P-V curve of 2-bus system with Q support from synchronous generator. TSO bus voltage shown in bracket corresponding to base scenario for the same P transfer

400 kV line loading (MW)	TSO bus voltage (p.u)	Q support (MVAr)
-987.77	0.996	81.50
-360.76	1.002	-47.90
33.82	1.000 (1.061)	0
773.37	0.981 (0.709)	389.18
889.70	0.975	500
912.83	0.937	500

BB3 bus voltage has been regulated to 1 p.u. till the P transfer limit is reached with the help of synchronous generator. Comparison of maximum power transfer limits in the base scenario and synchronous generator scenarios is given in Table 3.7. It can be seen that the P_{max} limit has been increased by 18.1% (139.9 MW) by adding a synchronous generator that provides both active and reactive power to the network. The increase in P transfer limit is less compared to synchronous condenser scenario. The difference is discussed in the next section.

Table 3.7: Comparision of Maximum power transfer limits for 2-bus system and adding a synchronous generator

	Base scenario	Adding a synchronous generator	Increase
P_{max} (MW)	772.93	912.83	139.9 (18.1%)

3.2.4 Comparison of adding synchronous condenser vs adding synchronous generator

In the previous sections, it was observed that improvement in P transfer limit is 200 MW lesser in synchronous generator scenario compared to synchronous condenser scenario. Major cause behind this is the increased Q losses in T3 and T2 transformers. This is explained as follows:

- Figure 3.7 shows that P transfer in 400 kV line is improved more in the case of synchronous condenser than in the case of synchronous generator.
- Synchronous generator adds 1000 MW active power generation into the system compared to synchronous condenser scenario. So the critical scalable load in the system was increased to 1909.07 MW in synchronous generator case (P transfer through 400 kV line + 1000 MW local generation).
- In the case of synchronous condenser, critical scalable load in the system was equal to P transfer limit only.

Comparison of P transfer limits and total scalable load in the system for synchronous condenser and synchronous generator scenarios are given in Table 3.8.

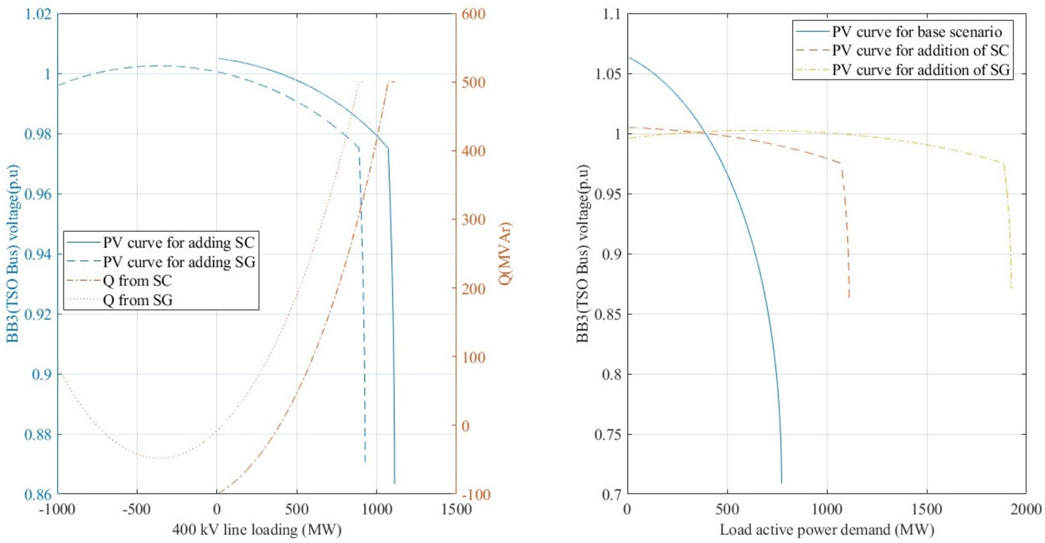

Figure 3.7: Left: PV curves at TSO bus for adding synchronous condenser vs adding synchronous generator; Right: TSO bus voltage with respect to load demand

Table 3.8: Comparison of Maximum power transfer, critical scalable demand and Q level when line loading is zero in synchronous condenser vs synchronous generator cases

	Synchronous condenser	Synchronous generator
Maximum power transfer (MW)	1112.4	912.83
Critical scalable demand (MW)	1112.4	1909.07
Q injection (MVAr) at $P_{400kVline} = 0$	-98.77	-5.69

- Reactive power requirement from the synchronous machine also varies in both the cases. Q losses in the step up transformer at the synchronous generator (T3) and tap changing transformer (T2) at the load differs in both the cases. In Figure 3.7, Q requirement from the synchronous machine was different when the 400 kV line loading was zero. Synchronous condenser absorbed 98.77 MVAr at zero line loading point. Synchronous generator absorbed 5.69 MVAr at the same point as the remaining excessive reactive powers were consumed by the transformers T2 and T3. This difference in Q level caused by Q losses in T2 and T3 transformers.
- Figure 3.8 shows T3 transformer has increased Q losses (49.99 MVAr) in synchronous condenser as it transfers 1000 MW in synchronous generator scenario, but there is no active power transfer in synchronous condenser case (0.5 MVAr).
- T2 transformer Q losses increases with increase in load. Since the total scalable load in synchronous generator case is higher than synchronous condenser case, Q losses also higher in synchronous condenser case for T2 transformer.
- The amount of reactive power injected when the active power starts to flow from external grid towards load is high in the case of synchronous generator than in the case synchronous condenser 3.8. Because of this, synchronous generator reaches it's Q limit earlier compared to synchronous condenser case.

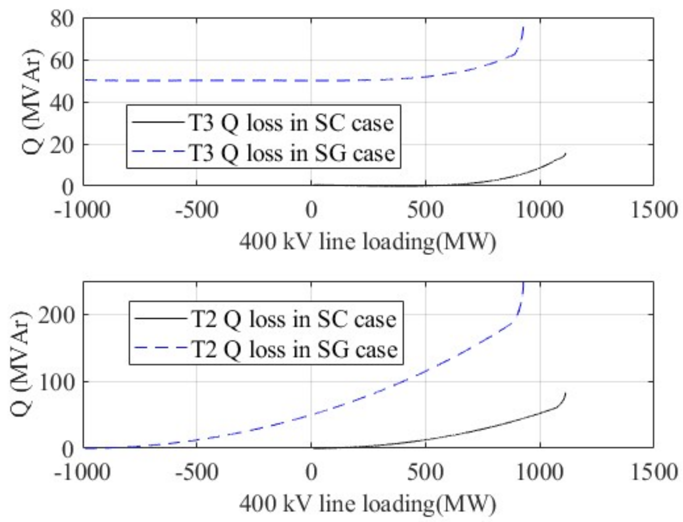

Figure 3.8: Comparison of T2 and T3 transformer Q losses in the case of synchronous condenser vs synchronous generator

Table 3.9 shows that for the same TSO bus (BB3) voltage, 400 kV line loading is different in the synchronous generator and synchronous condenser cases, since at each load level the sum of Q at 400 kV line and T2 and T3 transformer Q losses vary in both the cases.

Table 3.9: Comparison of 400 kV line loading for same BB3 bus voltage in synchronous condenser and synchronous generator scenarios

	400 kV line loading (MW)	
BB3 (TSO bus) voltage (p.u.)	Synchronous condenser	Synchronous genreator
1.00	369.00	0
0.99	748.69	500.36
0.975	1072.64	888.37

3.2.5 Increasing Q limit of synchronous generator to reach the same P transfer limit as in the case of synchronous condenser

From the previous section, it can be seen that the P transfer limit is 200 MW lesser in the case of synchronous generator than in the case of synchronous condenser. In order to achieve the same P transfer limit, the Q limit of synchronous generator was increased to 800 MVAr and it is found that with 800 MVAr Q support from synchronous generator with 1000 MW active power generation, it is possible to achieve the same P transfer limit as in the case of synchronous condenser. This is shown in Figure 3.9. Solid curve shows the P-V curve with increased Q limit of synchronous generator. Dashed curve shows P-V curve with synchronous condenser. Dotted curve shows Q support from synchronous generator and dash-dotted curve shows Q support from synchronous condenser.

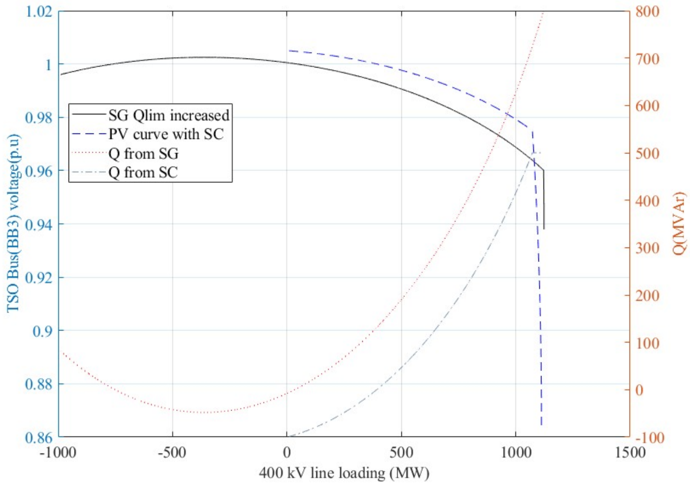

Figure 3.9: Increasing Q limit of synchronous generator to achieve same P transfer limit as in synchronous condenser case

3.3 Improving 400 kV transmission line transfer capacity and voltage by adding distributed generation in the distribution grid

The synchronous generator was replaced with DG connected to TSO bus (BB3) through proper step up transformers and a 135 kV line in between as shown in Figure 3.10. The length of 135 kV line was assumed to be zero for initial analysis. The parameters of transformer T4, T5 and T6 and DG along with 135 kV line are listed in Table 3.10.

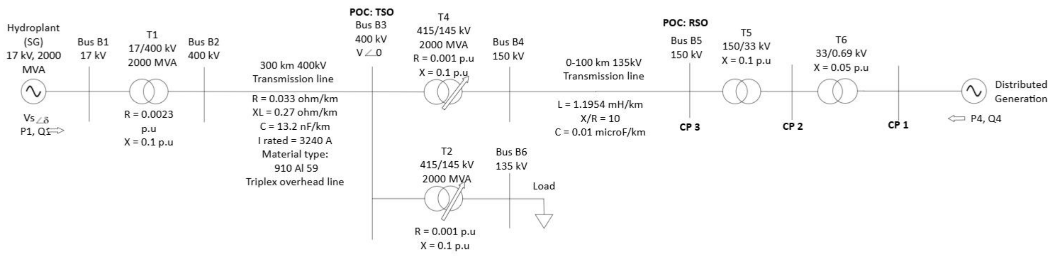

Figure 3.10: One line diagram showing synchronous generator replacement with DG

Table 3.10: Network parameters of the elements added in the case of DG replacement

Element	Parameters
DG	0.69 kV, 1111 MVA, 0.9 PF, Q limit ±0.5 P_{max}
T4 transformer	415/145 kV, 2000 MVA, R = 0.001 p.u., X = 0.1 p.u.
T5 transformer	150/33 kV, 2000 MVA, X = 0.1 p.u.
T6 transformer	33/0.69 kV, 2000 MVA, X = 0.05 p.u.
135 kV Transmission line	L = 1.1954 mH/km, X/R = 10, C = 0.01 F, Line length: 0-100 km

With this configuration, the impedance between TSO bus was increased to 0.25 p.u (0.1 p.u. in the case of synchronous generator case). DG terminal voltage is controlled to 1 p.u. using voltage control mode. Figure 3.11 shows comparison of P-V curves for synchronous generator addition to 2-bus system and replacing synchronous generator with DG.

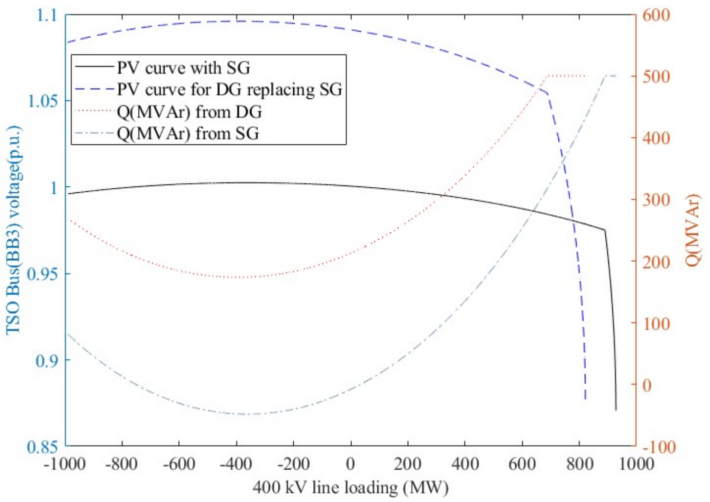

Figure 3.11: P-V curves for synchronous generator case and DG replacing synchronous generator with their Q support

- The solid curve shows the P-V curve with synchronous generator connected to transmission grid and the dashed curve shows the P-V curve with DG connected to distribution grid. From these two curves, it can be observed that the maximum power transfer limit is reduced by 10.04% (91.65 MW) as shown in Table **??**.
- The dash-dotted curve shows Q support from synchronous generator and the dotted curve shows the Q support from DG. It can be seen from these two curves that for the same Q_{max} limit of 500 MVAr, DG reaches its Q limit earlier than synchronous generator.
- When the load demand increases, active power generated by DG is supplied to local load, eventually power flow towards grid in the 400 kV line reduces. This results in decreased inductive losses in the 400 kV line. So the reactive power generated by DG also reduces. Through simulation, it is observed that the minimum of Q generation from DG is 173.71 MVAr when the P transfer is 393.28 MW towards grid. As the power flow in the 400 kV line is reduced, 400 kV bus voltage increases. When the line flow is 393.28 MW, TSO bus voltage raises upto 1.096 p.u.
- After this point, DG starts to increase the reactive power injection and eventually reaches its limit when the line loading is 687.72 MW. Once the Q limit is reached, voltage falls rapidly and reaches the critical load point. The maximum power that can be transferred in the network in DG case is 821.18 MW. The comparison between synchronous generator case and DG case is listed below in table 3.12. As the Q limit reaches earlier in DG case than Nuclear case, the maximum power transfer is high (912.83 MW) in the case synchronous generator than DG (821.179 MW) 3.11.

Table 3.11: Maximum power transfer limits in the case of synchronous generator and Replacing synchronous generator with DG

	synchronous generator (MW)	Replacing synchronous generator with DG (MW)	Decrease in case of DG replacement
P_{max}	912.83	821.18	91.65 (10.04%)

Table 3.12: Key points in P-V curve for DG replacing synchronous generator

400 kV line loading (MW)	TSO bus voltage (p.u) in DG (SG) case	Q support in MVAr from DG (SG)
-989.966	1.084 (0.996)	269.064 (80.6022)
-393.277	1.096 (1.002)	173.71 (-47.6)
687.716	1.05432 (0.984)	500 (317.18)
821.179	0.876163 (0.978)	500 (431.79)

3.3.1 Comparison of Q injection from DG vs synchronous generator

Figure 3.12 represents how the reactive power generated from DG is utilized by different network elements. Left plot of Figure 3.12 shows the comparison of Q output from DG and SG at 400 kV side. It can be observed that in order to transfer the same amount of active power in the 400 kV line, more Q is needed from DG than in the case of synchronous generator. This can be explained with the help of two port equations.

$$\{P_{DG} + \frac{|V_{DG}|^2}{|Z|}\sin\theta\}^2 + \{Q_{DG} + \frac{|V_{DG}|^2}{|Z|}\cos\theta\}^2 = \{\frac{|V_{DG}||V_{TSObus}|}{|Z|}\}^2 \tag{3.1}$$

In the above equation,

- P_{DG} is the active power generation by DG which is equal to 1000 MW or 0.9 p.u.
- V_{DG} is the DG terminal voltage which is controlled to 1 p.u. in this case.
- $|Z|$ is the magnitude of impedance between DG and TSO bus i.e., 0.25 p.u.
- θ is the loss angle arctan $\frac{R}{X}$, calculated as 0.2292 rad
- $|V_{TSObus}|$ is the magnitude of TSO bus voltage. Through simulation it is obtained at 1.083 p.u.

With the help of the above known quantities, Q generated from DG can be calculated as 260 MVAr by hand calculation. The simulation results showed that Q generation from DG is 269.064 MVAr.

With the help of 2-port equation, it can be understood that, when the impedance between the generation and TSO bus increases, the Q demand at TSO bus also increases. In synchronous generator scenario, impedance between generation and TSO bus was 0.1 p.u. This was increased to 0.25 p.u. when replacing synchronous generator with DG. This increase in impedance had caused increase in Q demand at 400 kV bus (BB3).

Increased impedance is caused by the transformers T4, T5 and T6. Sum Q losses in the transformers T2, T4, T5 and T6 in the case of DG is higher than sum of Q losses in T2 and T3 transformers in the case of synchronous machine based generation. This is shown in right side of Figure 3.12.

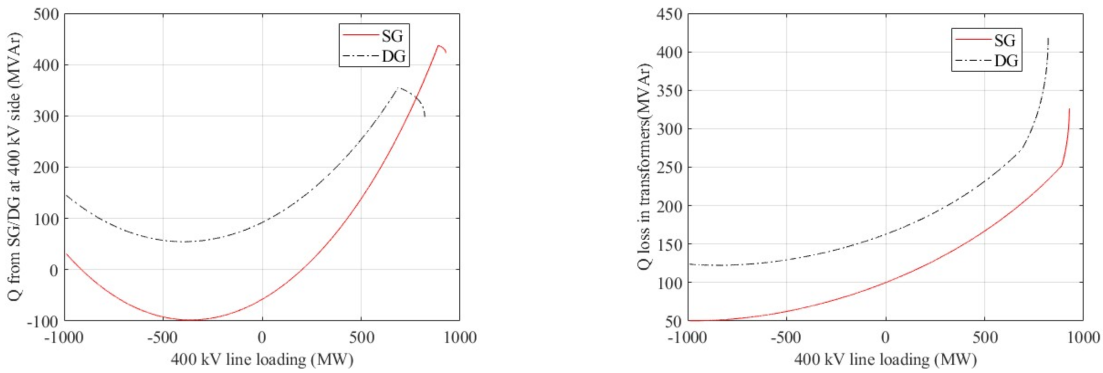

Figure 3.12: Q from DG vs SG - Q at 400 kV side and Q losses in transformers. Left: Q from SG vs DG at 400 kV side; Right: Q losses in transformers in DG vs SG case.

As the Q injection from DG is high (269.064 MVAr) at minimum load condition, TSO bus (BB3) voltage is high (1.083 p.u.). Figure 3.13 shows DG terminal voltage is controlled to 1 p.u. till DG reaches its Q limit. DG tries to keep the voltage at its terminal to 1 p.u irrespective of the network conditions.

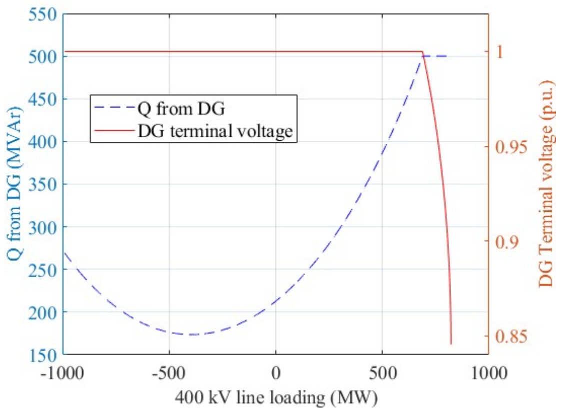

Figure 3.13: DG terminal voltage controlled to 1 p.u under V control mode at DG terminal

From Figure 3.11, it can be seen that even though the voltage of the TSO bus (BB3) is high, DG still injects Q instead of absorbing. This contradicts the synchronous generator scenario. The synchronous generator connected to the transmission grid regulates the voltage of the TSO bus (BB3) to 1 p.u. by controlling its reactive power output as shown in Figure 3.5. The difference in behaviour can be explained with the help of voltage control mode at DG terminal applied in this case. Since the DG terminal is controlled to 1 p.u., the control mechanism aims to control the DG terminal voltage to 1 p.u. for varying load conditions by varying its Q output as shown in figure 3.13. But it is not controlling the TSO bus BB3 voltage to 1 p.u.

3.4 Comparision of different control modes of DG

With DG replacement, it is possible to control voltage and reactive power at different points other than its terminal. Few other cases are considered below:

- V control at 33 kV bus (BB7)
- V control at 135 kV bus (BB6)
- Q control at 135 kV bus (BB6)

3.4.1 V control at different points

From the previous section, it was observed that DG injects 269.064 MVAr when DG terminal voltage is controlled to 1 p.u. using voltage control mode. Corresponding Q from DG measured at 400 kV bus side is 145.46 MVAr after subtracting losses in the transformers in between. Using station controller, BB7 (33 kV bus) and BB6 (135 kV bus) were also controlled to 1 p.u. with voltage control mode. It was observed that when the voltage control point is moved away from DG, Q injection from DG also increases. Q injection from DG increases in the following order:

DG terminal < BB7 (33kV bus) < BB6 (135 kV bus)

This results is attaining Q limit in the above order of control points.

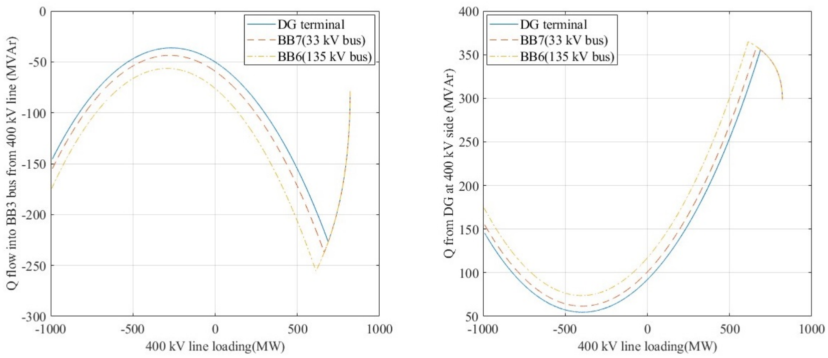

Figure 3.14: Comparison of DG voltage control at different points. Left: Q injected into BB3 (TSO bus) from 400 kV line; Right: Q injected by DG measured at BB3 (TSO bus) side

- Right plot of Figure 3.14 shows that DG injected by Q increases as the control points is moved away from DG. Left plot of Figure 3.14 shows that Q support provided by grid i.e., Q injected by 400 kV line into BB3 bus reduces as Q injected by DG increases at different control points.
- Table 3.13 gives a summary of Q from DG and 400 kV line at 400 kV side for minimum load condition, minimum Q level from DG and maximum P transfer conditions. From right side of Figure 3.14 it also can be observed that once the Q limit is reached, DG behaves like a constant Q source. All the three P-V curves follow the same curve.
- Critical scalable demand is equal in all the three cases of voltage control (1818.12 MW) and the corresponding P transfer at that condition is 821.18 MW. The difference between Q injected by DG at 400 kV side and Q injected by 400 kV line into

BB3 (400 kV bus) can be explained with the help of Q losses in the load transformer T2.

- Figure 3.15 shows that Q level measured at 400 kV side is equal to Q injected from 400 kV line into BB3 bus and the Q losses in the load transformer T2.

Table 3.13: Comparison of Q from DG and 400 kV line at BB3 (TSO bus) side for V control at DG terminal, BB7 (33 kV bus) and BB6 (135 kV bus)

Control point	Q from DG measured at 400 kV side (MVAr)	Q from 400 kV line into BB3 (400 kV bus) (MVAr)
400 kV line loading = -989 MW (Minimum load condition)		
DG terminal	-145.1	145.46
BB7 (33 kV bus)	-154.91	154.86
BB6 (135 kV bus)	-172.85	173.2
400 kV line loading = -400 MW (Min Q level from DG)		
DG terminal	-39.78	54.75
BB7 (33 kV bus)	-46.8	61.67
BB6 (135 kV bus)	-59.14	73.84
400 kV line loading = P at Q_{max}		
DG terminal (687.81)	355.66	-226.7
BB7 (33 kV bus) (664.55)	358.94	-236.99
BB6 (135 kV bus) (613.87)	364.82	-255.52

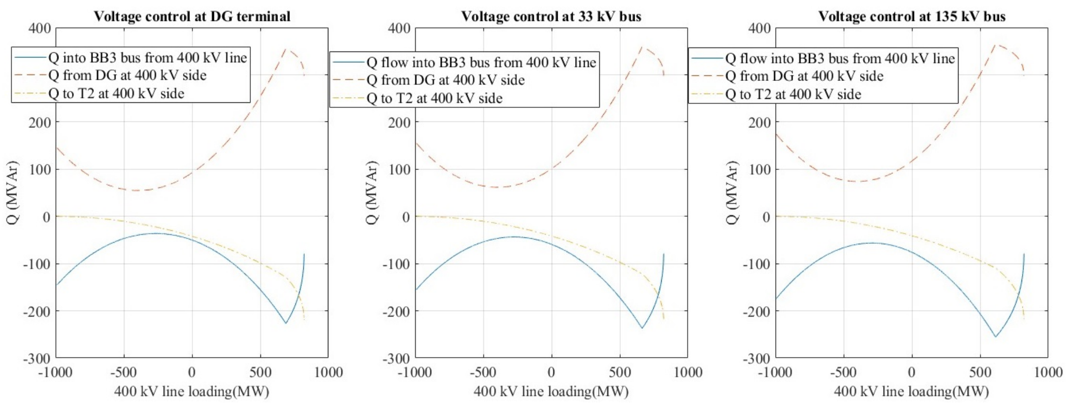

Figure 3.15: Q balance at BB3 (TSO bus) with voltage control mode at different points

Figure 3.16 shows how P-V curves vary for voltage control at different points. In the previous section it was analyzed that over voltage exists at BB3 (TSO bus) as the Q injection from DG is high during voltage control at DG terminal. Now, Q from DG further increases as Q level increases when the control points moved further away from DG. This results is more over voltage in BB3 (TSO bus). Voltage levels at BB3 (TSO bus) at different cases are listed in Table 3.14.

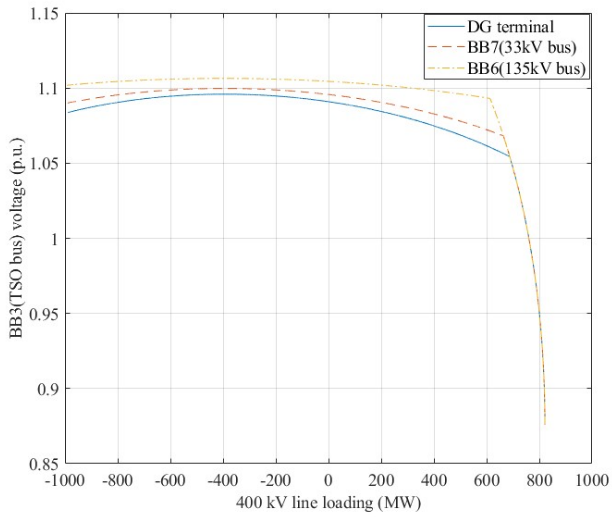

Figure 3.16: P-V curves for voltage control at DG terminal, 33 kV bus (BB7) and 135 kV bus (BB6)

Table 3.14: Over voltage observed in P-V curves for voltage control mode at different points in DG scenario

P transfer (MW)	DG terminal (p.u.)	BB7 (33 kV bus) (p.u.)	BB6 (135 kV bus) (p.u.)
-989 (Minimum load condition)	1.084	1.096	1.054
-400 (Min Q level from DG)	1.09	1.10	1.069
P at Q_{max}	1.102 (687.81)	1.106 (664.55)	1.093 (613.87)

3.4.2 V control at 400 kV bus

In this section, DG with voltage control at BB3 (TSO bus) is examined. Figure 3.17 shows P-V curves for synchronous generator connected to transmission grid vs DG controlling BB3 (TSO bus) voltage to 1 p.u. scenarios. Q from synchronous generator/DG measured at 400 kV side is also plotted.

- Synchronous generator terminal voltage is controlled to 1 p.u. So, it generates or absorbs Q in order to transfer the 1000 MW produced by it to the grid or load.
- In contrast, DG controls the BB3 (TSO bus) directly to 1 p.u.
- There is a slight difference in Q level measured at 400 kV side of DG/synchronous generator. This is due to difference in control point location in the two cases.

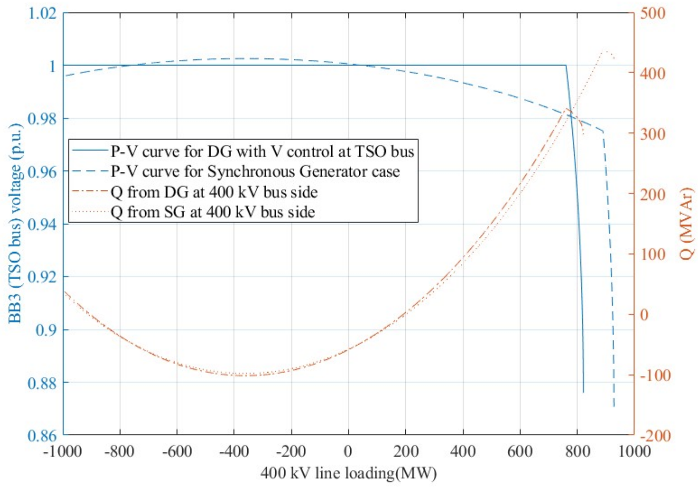

Figure 3.17: P-V curves for synchronous generator vs DG with voltage control at TSO bus scenarios

Figure 3.18 shows Q balance at BB3 (TSO bus) in the two scenarios DG controlling TSO bus to 1 p.u. and synchronous generator connected to TSO bus. In both the cases, it was observed that DG/SG is responsible for Q needed by 400 kV line at BB3 bus side and the load transformer T2 operation.

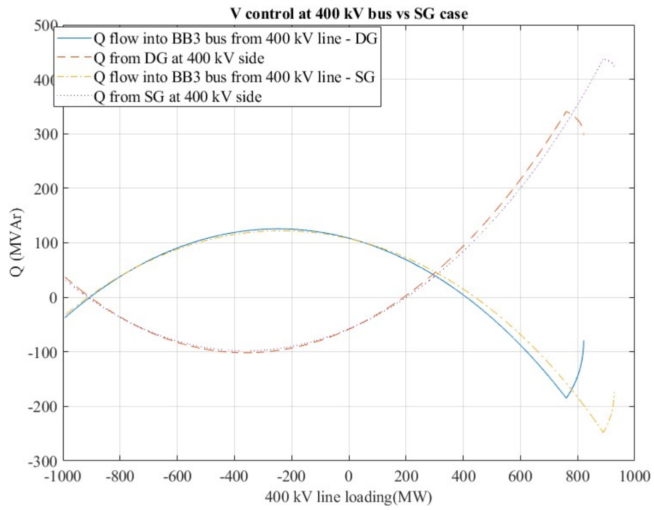

Figure 3.18: Q balance at BB3 (TSO bus) in DG voltage control at 400 kV bus vs synchronous generator cases

Figure 3.19 shows the Q losses in the transformers between the source and TSO bus in the two cases. In synchronous generator case, there is only one transformer (T3) between generator and TSO bus. In DG case, there are three transformers T4, T5 and T6 between DG and TSO bus. It is evident that there will be more Q losses associated with these transformers. This drives DG Q limit to saturate earlier compared to synchronous generator case.

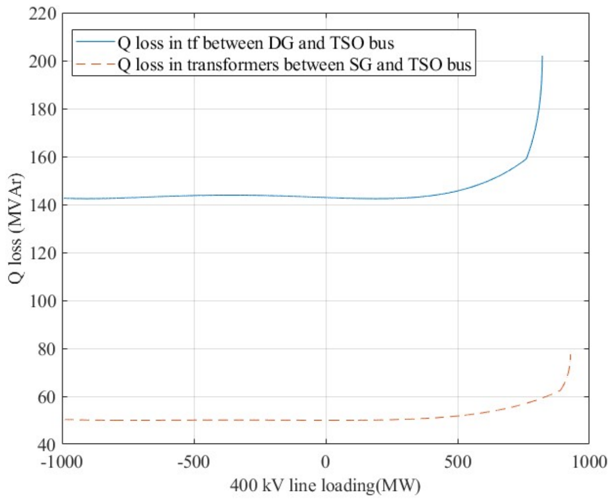

Figure 3.19: Q losses in transformers in DG with voltage control at 400 kV bus vs synchronous generator cases

3.4.3 Q control at 135 kV bus

With Q control mode at BB6 (135 kV bus), Q is set to 0 MVAr at that bus. Grid supports BB3 bus to remain in operation. Grid supplies Q needed by 400 kV line, T2 and T6 transformers. Figure 3.20 shows Q balance at BB3 (TSO bus) at Q control mode. It can be seen from this figure that DG absorbs Q from the network in order to keep the MVAr at BB6 (135 kV bus) to zero. The amount of Q needed at such case is supplied by the grid. In addition to that, Q losses in the load transformer T2 also supplied by the grid. Q injected by 400 kV line into BB3 bus is equal to sum of T2 transformer Q losses and Q measured at 400 kV side of DG at all operation points. This is shown in Table 3.15.

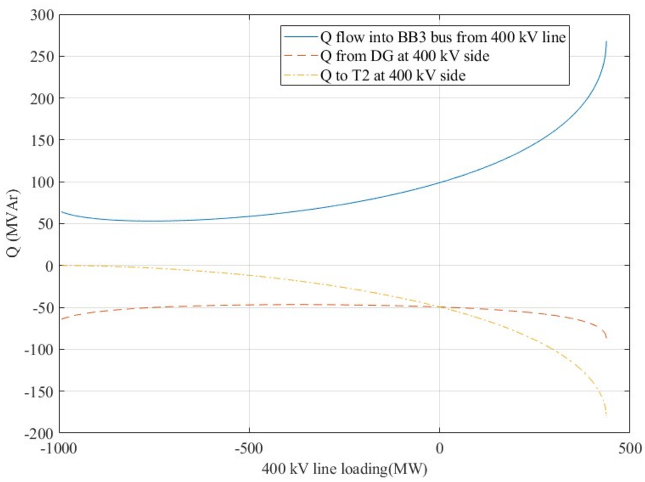

Figure 3.20: Q balance at BB3 bus with Q control at BB6 (135 kV bus)

Table 3.15: - Q balance at BB3 (TSO bus) at DG with Q control at BB6 (135 kV bus)

400 kV line loading (MW)	Q from 400 kV line into BB3 (TSO bus) (MVAr)	Q from DG at 400 kV side (MVAr)	T2 transformer Q losses (MVAr)
-993.084	64.14	-64.14	0
-501.086	58.60	-46.95	-11.64
437.78	266.58	-181.07	-86.82

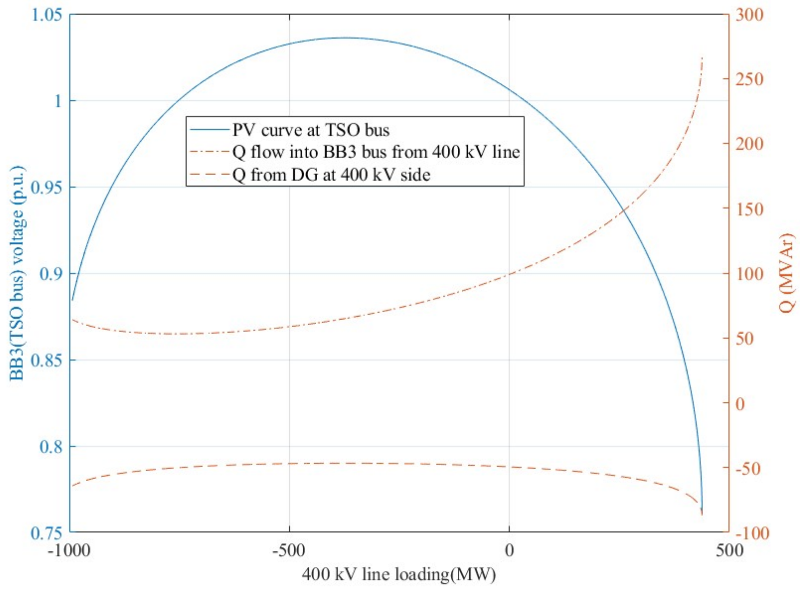

Figure 3.21: P-V curves for Q control at BB6 (135 kV bus)

- From the P-V curve at BB3 (TSO bus) for the Q control scenario at BB6 (135 kV bus) shown in Figure 3.21, it can be seen that voltage at TSO bus when transferring 1000 MW generated by DG towards external grid is very low (0.884 p.u.) as the Q output from DG at this point is negative (Q absorption by DG = -64.14 MVAr) in order to keep the Q at 135 kV bus equal to zero.
- When the load is gradually increased, DG P output is supplied to local load, 400 kV line loading towards grid starts to decrease. When the line loading decreases, reactive losses in the overhead line also decreases. This helps to improve the BB3 (TSO bus) voltage. When the line loading is 373.343 MW, TSO bus voltage raises up to 1.036 p.u. After this point, TSO bus voltage starts to decrease as the load power demand becoming more.
- Through simulation it is observed that load flow stops converging when the P transfer in 437.78 MW from the grid to load. At this point, BB3 (TSO bus) voltage drops to 0.761 p.u. It should be noted that Q absorption from DG at this point is equal to -86.82 MVAr only. Q limit of DG is not reached. Still the system voltage collapsed. When using Q control mode, Q limit of DG is not fully utilized.
- Q injection from 400 kV line into BB3 bus at maximum P transfer point is obtained as 266.58 MVAr. Grid is not able to supply more reactive power than this limit through the 400 kV line. So the stability is lost.

Table 3.16 shows TSO bus voltage for different Q levels from DG in the Q control mode scenario.

Table 3.16: BB3 (TSO bus) voltage and corresponding Q output from DG under Q control mode at BB6 (135 kV bus)

400 kV line loading (MW)	BB3 (TSO bus) voltage (p.u.)	Q from DG (MVAr)	Q from 400 kV line (MVAr)
-993.09 (Min load condition)	0.884	-64.14	64.14
-373.34 (Max voltage at TSO bus)	1.036	-46.629	64.90
437.78 (P_{max})	0.761	-86.82	266.58

Comparing to voltage control mode, critical scalable demand and maximum power transfer limit has reduced in the case of Q control mode. This is shown in Table 3.17.

Table 3.17: Comparison of P transfer limit and critical scalable demand in voltage control and Q control modes

Control mode	P_{max} (MW)	Critical Scalable Demand (MW)
V control at DG terminal	687.81	1818.18
V control at BB3 (33 kV bus)	664.55	1818.18
V control at BB6 (135 kV bus)	613.87	1818.18
Q control at BB6 (135 kV bus)	437.78	1435

3.5 Improving 400 kV transmission line transfer capacity and voltage in case of DG

3.5.1 Increasing Q limit of DG

One way of reaching same P_{max} as synchronous generator in the case DG replacement with voltage control at its terminal is increasing the Q limit of DG. When the Q limit of DG in increased to 637.71 MVAr, the line loading from grid to load can be increased to the 925.85 MW, which is nearer to P_{max} in the case of synchronous machine-based generation (927.94 MW). This can be seen from figure 3.22.

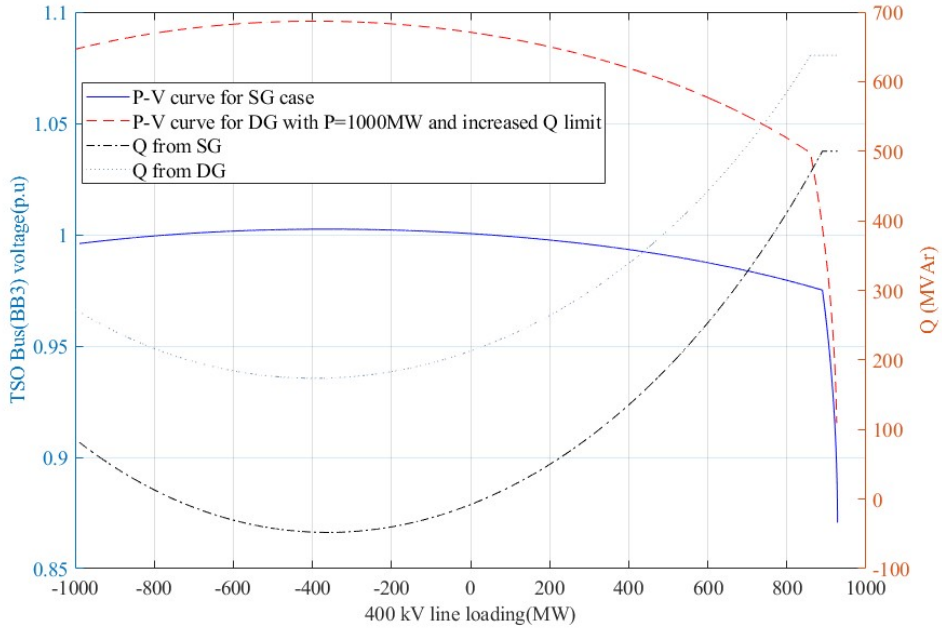

Figure 3.22: P-V curves for increasing Q limit of DG to have same P_{max} as synchronous generator

3.6 Adding synchronous condenser to TSO bus

Another way to achieve the same P_{max} as that of synchronous generatorthe nuclear case is to add shunt compensation in the form of synchronous condenser to the TSO bus directly. The size of synchronous condenser needed in this case for a simple system is 120 MVAr. Instead of synchronous condenser (rotating VAr compensator), power electronic interfaced static VAr compensators like STATCOM can be used. They are efficient and compact compared to synchronous condenser, but expensive and requires complex control strategies.

- Figure 3.23 shows how P transfer limit in the case of DG with voltage control at its terminal can be improved as compared to synchronous generator case by adding shunt compensation at TSO bus. From this figure, it can be seen that the synchronous generator that has been added to the system is at its $-Q_{max}$ limit till DG reaches its Q limit.
- When the line loading is 508.35 MW, DG reaches its Q limit. Once the DG reaches its limit, synchronous condenser starts to inject reactive power into TSO bus. From this point, voltage at BB3 (TSO bus) is regulated near to 1 p.u.
- When the Q limit of DG is reached, synchronous condenser starts to inject Q to prevent the transmission voltage falling below 1 p.u till the synchronous condenser reaches its Q limit. Thus the synchronous condenser regulates the TSO bus voltage to 1 p.u. Here the size of synchronous condenser is chosen in a way to attain the same P_{max} as in the case of Nuclear.
- For the same level of P transfer with increased Q support with the two cases discussed above, it can be observed that size of synchronous condenser is 17 MVAr

lesser than Q limit needed to be increased at DG.

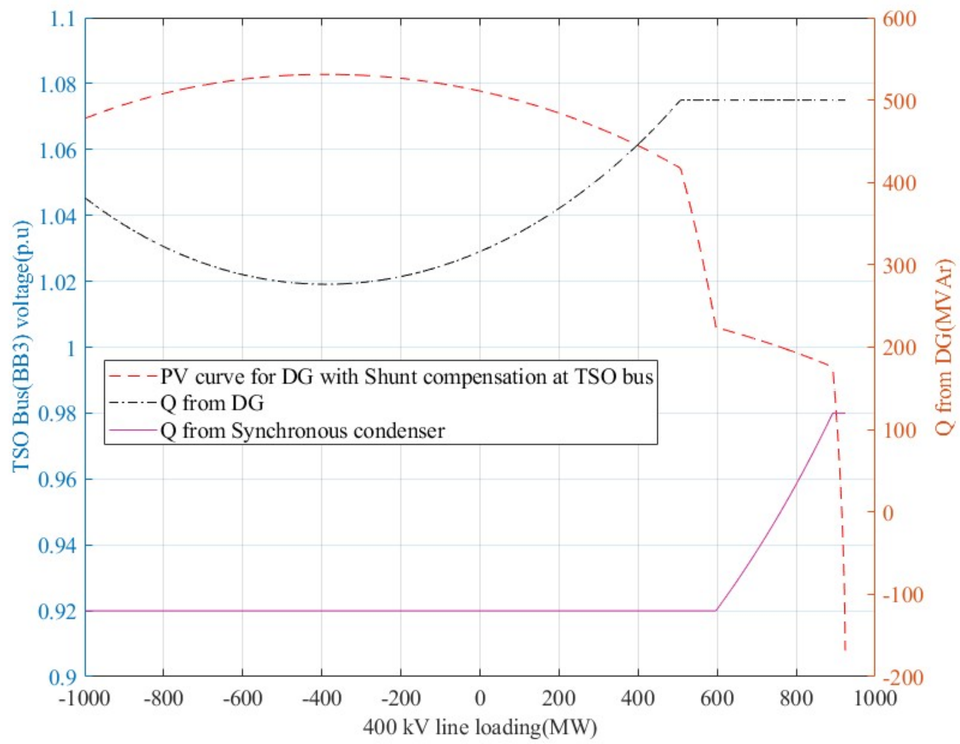

Figure 3.23: P-V curves for adding synchronous condenser to TSO bus in the case of DG to have same Pmax as synchronous generator

4

Voltage Stability Analysis of Nordic-32 System

4.1 Overview of Nordic-32 system

In this thesis work, voltage stability assessment is performed in IEEE/CIGRE Nordic-32 benchmark model [7]. The single line of the nordic-32 system is shown in figure 4.1.

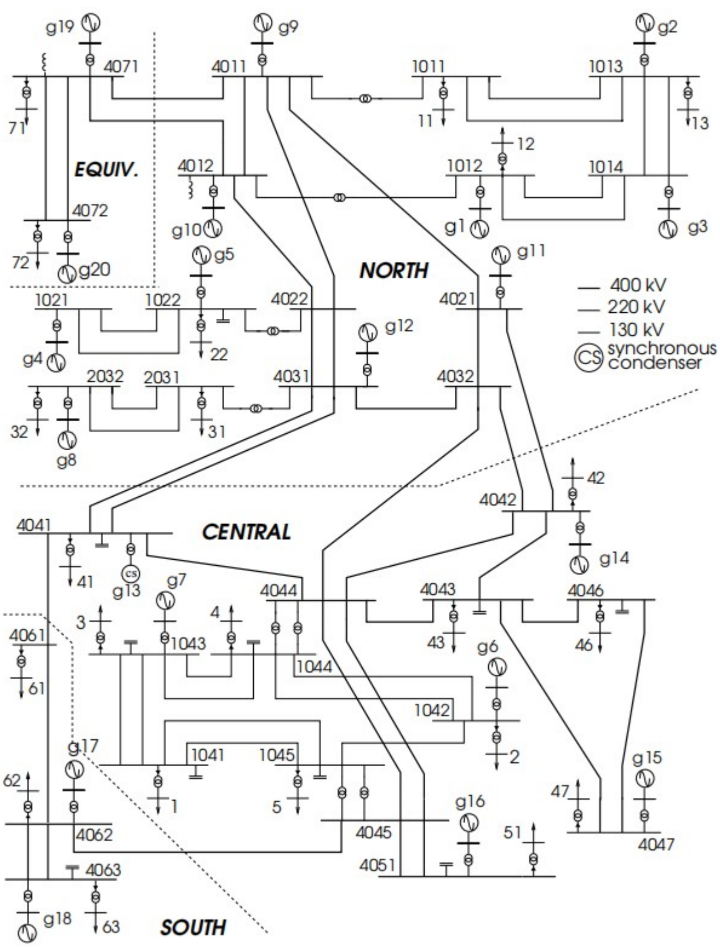

Figure 4.1: One line diagram for Nordic-32 Test System © IEEE 2015 The Institute of Electrical and Electronics Engineers, Inc

The system is split into four areas named North, Central, South and Equivalent system of

external grid. North part of sweden has more conventional generation. Active power generated in north sweden in transferred to central sweden through five 400 kV transmission lines L4031-4041a, L4031-4041b, L4032-4044, L4032-4042 and L4021-4042 to 4041, 4042 and 4044 buses. Total generated power and consumed power in the nordic-32 test system are 11505.9 MW and 11060.0 MW respectively. The nordic-32 model contains 74 buses among which 32 are transmission buses, 22 distribution buses and 20 generator terminals. It also contains 102 branches, that includes 22 distribution transformers and 20 step up transformers.
Maximum power that can be transferred from north to central sweden is influenced by the reactive power support at the 400 kV buses 4041, 4042 and 4044. Also, Load Tap Changers (LTC) try to restore load levels by restoring voltage levels in distribution bus bars. When the P transfer limit is smaller than the load demand that LTC tries to restore, long-term Voltage instability occurs.

4.1.1 TSO and DSO buses in central and south sweden - generators, loads and reactive power support connected to them

Central part of sweden network has eight 400 kV buses 4041, 4042, 4043, 4044, 4045, 4046, 4047 and 4051. The details are listed in Table 4.1. Also it has five 130 kV buses 1041, 1042, 1043, 1044 and 1045. The DSO bus details are given in Table 4.2. South sweden has three 400 kV buses 4061, 4062 and 4063. The generators and loads connected to it are given in Table 4.3. The reference model of Nordic-32 system [7] had the Q limits equal to ±1 p.u. of rated MVA. In this thesis work, Q limit was modified to $\pm 0.5 P_{max}$.
From these tables, it can be seen that each bus is getting reactive power support by means of the generators/synchronous condenser connected to them directly or from nearby buses. In addition, some buses are equipped with fixed capacitor also to regulate the voltage level. All the 130 kV and 400 kV buses except 4044 and 4045 buses are connected with loads.

Bus ID	Gen	P out (MW)	Q limit [7] (MVAr)	Q limit updated (MVAr)	Shunt cap (MVAr)	Load P (MW)	Load Q (MVAr)
4041	g13 (CS)	0	±300	±142.5	200	540	131.4
4042	g14	630	±700	±315	N/A	400	127.4
4043	N/A	N/A	N/A	N/A	200	900	254.6
4044	N/A	N/A	N/A	N/A	N/A	N/A	N/A
4045	N/A	N/A	N/A	N/A	N/A	N/A	N/A
4046	N/A	N/A	N/A	N/A	100	700	211.8
4047	g15	1080	±1200	±540	N/A	100	44.0
4051	g16	630	±700	±315	100	800	258.2

Table 4.1: 400 kV bus in central sweden, loads, generation and Q compensation connected with them

Bus ID	Gen	P out (MW)	Q limit [7] (MVAr)	Q limit (MVAr)	Shunt cap (MVAr)	Load P (MW)	Load Q (MVAr)
1041	N/A	N/A	N/A	N/A	250	600	148.2
1042	g6	360	±400	±138.6	N/A	330	71.0
1043	g7	180	±200	±60.4	200	260	83.8
1044	N/A	N/A	N/A	N/A	200	840	252.0
1045	N/A	N/A	N/A	N/A	200	720	190.4

Table 4.2: 130 kV bus in central sweden, loads, generation and Q compensation connected with them

Table 4.3 gives generators and loads associated with 400 kV buses 4061, 4062 and 4063 present in south sweden. 4062 and 4063 buses are connected with generators and loads. 4061 bus connected with load only. All the three buses do not have any other form of Q support like shunt capacitors/synchronous condenser directly connected to them.

Bus ID	Gen	P out (MW)	Q limit [7] (MVAr)	Q limit (MVAr)	Shunt cap (MVAr)	Load P (MW)	Load Q (MVAr)
4061	N/A	N/A	N/A	N/A	N/A	500	122.5
4062	g17	540	±600	±270	N/A	300	83.8
4063	g18	1080	±1200	±540	N/A	590	264.6

Table 4.3: 400 kV bus in south sweden, loads, generation and Q compensation connected with them

Voltage stability assessment is carried out on the three buses 4041, 4042 and 4044 that are connected to north sweden for different generation mix scenarios. P-V analysis was performed with initial load scaling of 0.75.

4.1.2 P-V curves of 4041, 4042 and 4044 buses with present reactive power support in the nordic-32 model

Figure 4.2 shows the P-V curves at 4041, 4042 and 4044 buses that are connecting north and central sweden. The P transfer level is controlled by the net Q available at these buses based on the equation 2.2. If the Q support available at each bus is modified in other generation mix scenarios, P transfer limit is affected. In the subsequent sections, how the P transfer limit is affected with these generation mix scenarios is analyzed.

The key points in Figure 4.2 is given in Table 4.4. In Figure 4.2, it can be observed that P-V curves at 4041 and 4042 buses have higher voltage gradient, but 4044 bus has smaller voltage gradient. The reason is explained as follows: Higher voltage gradient implies higher $\frac{dQ}{dV}$ sensitivity. Figure 4.2 shows that voltage gradient in buses 4041 and 4042 is comparatively higher than at bus 4044, which implies that they are more sensitive to change in reactive power reserve of the system. This can be due to P and Q loads connected to 4041 and 4042 buses. 4044 bus is not connected to any load directly at its terminal.

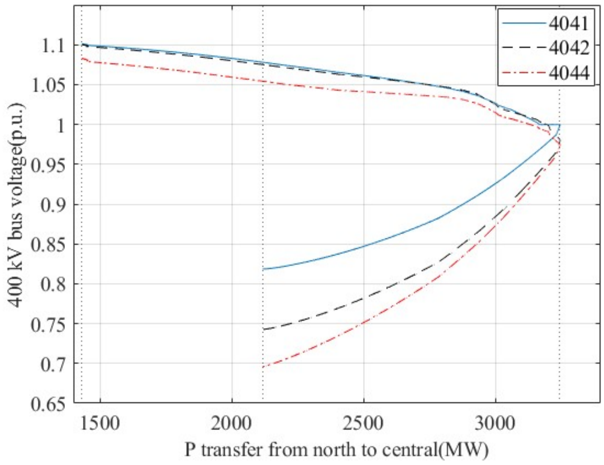

Figure 4.2: P-V curves of buses 4041, 4042 and 4044 that connects north and central sweden

Table 4.4: P-V curves at 4041, 4042 and 4044 buses - voltages at minimum, maximum and collapsing points

		400 kV bus voltage (p.u.)		
	P transfer (MW)	4041	4042	4044
Minimum	1432.49	1.101	1.101	1.083
Maximum	3246.66	1.000	0.98	0.974
Collapse	2118.15	0.819	0.743	0.696

4041 bus - P-V curve and reactive power support associated with it

Figure 4.3 shows P-V curve at 4041 bus and reactive power support available at that bus.

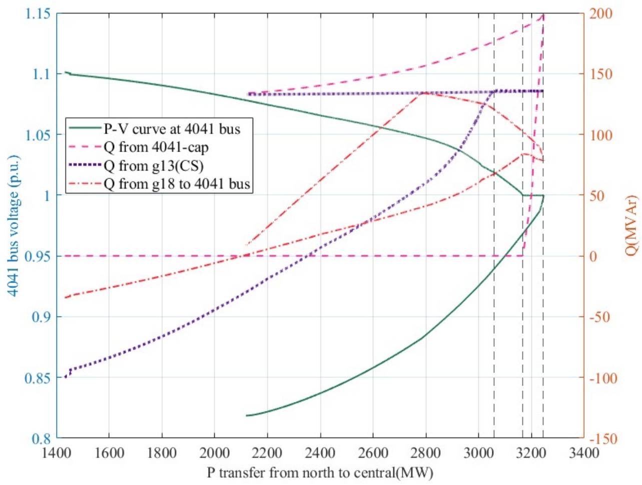

Figure 4.3: P-V curve at 4041 bus - Q support from g13 synchronous condenser, 4041-capacitor and g18 generator(4063 bus)

- 4041 bus is currently equipped with 142.5 MVAr Q support from g13 synchronous condenser and 200 MVAr shunt capacitor. 540 MW P load and 131.4 MVAr Q load is connected to the same bus.
- At minimum load in the system, bus voltage raises up to 1.101 p.u. Since the bus voltage is higher, synchronous condenser absorbs 100 MVAr from the bus. Shunt capacitor is turned off to avoid excessive over voltage. Generator g18 also absorbs Q at this over voltage condition.
- As the load is gradually increased, Q absorption by synchronous condenser decreases. When the bus voltage becomes 1.068 p.u., synchronous condenser stops absorbing Q from the system. In the simple system discussed in previous chapter, from Figure 3.3, it was observed that synchronous condenser does not inject or absorb Q from the bus when the bus voltage becomes 1 p.u. In the nordic-32 model, g13 synchronous condenser starts to inject Q from a higher voltage threshold.
- Synchronous condenser hits its Q limit of 142.5 MVAr (134.88 MVAr measured at HV side of the transformer Tr4041-g13), with the voltage at 4041 bus being 1.019 p.u. P transfer at this point is 3058.04 MW. Once the Q limit is reached, voltage gradient increased till the bus voltage reaches 1 p.u.
- Once the bus voltage reaches 1 p.u., 4041-capacitor starts to inject Q into the bus to prevent voltage falling below 1 p.u. Within the range of P transfer from 3166.62 MW to 3244.84 MW, shunt capacitor injects its 200 MVAr full capacity in steps of 1 MVAr to retain the bus voltage.
- At 3244.84 MW P transfer, both the g13 synchronous condenser and 4041-capacitor reach their limits. So the system voltage starts to fall for any further increase in load. The maximum power transfer limit in the existing system with synchronous machine based generation is obtained as 3244.84 MW. Since the voltage dependency of load is considered in the power flow execution, power consumption decreased as voltage decreased. P transfer also decreased.
- 4041-capacitor is shunt connected, when the voltage becomes less than 1 p.u., Q from capacitor decreases as Q is proportional to V^2.
- For the critical scalable load of 13834.6 MW in the system, 4041 bus voltage collapses. P transfer at this point is 2118.15 MW and the lowest bus voltage before collapsing is 0.819 p.u. It means when the load is increased beyond the maximum power transfer point, it is not able to draw the current as the load voltage starts to decrease.
- With the inclusion of static capacitor, the bus maintains voltage at 1 p.u at maximum power transfer limit of 3246.48 MW. It can be observed that when the load is compensated more and more, $tan\ \phi$ becomes smaller. This leads to voltage at maximum power transfer capability nearer to normal operation value. At this point, it is hard to distinguish stable and unstable operating regions [3].
- In Figure 4.3, the dash-dotted curve represents the reactive power support from g18 generator to 4041 bus, with Q measured at 4041 bus terminal. It can be observed that even before g18 generator reaches its Q limit, voltage at 4041 bus starts to fall. This implies that generators located far away do not help much to increase the maximum P transfer limit.

Table 4.5 lists down the points when synchronous condenser hits its limit, 4041-capacitor injects Q from 1 MVAr to 200 MVAr

Table 4.5: 4041 bus voltage and corresponding Q from g13(CS) and 4041-cap

P transfer (MW)	4041 bus voltage (p.u.)	Q from g13 (CS) (MVAr)	Q from 4041-cap (MVAr)	Q from g18 to 4041 bus (MVAr)
3058.04	1.019	134.88	0	67.62
3166.62	1	134.88	1	83.96
3244.84	1	134.88	200	78.05

4042 bus - P-V curve and reactive power support associated with it

Figure 4.4 shows P-V curve at 4042 bus and reactive power support available at that bus.

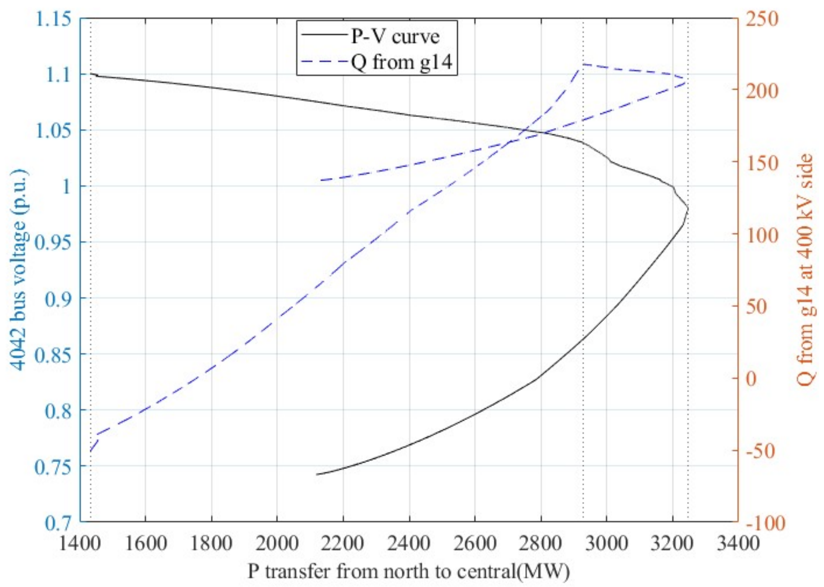

Figure 4.4: P-V curve at 4042 bus - Q support from g14 synchronous generator

- 4042 bus is equipped with Q support by the generator g14 only. The Q limit of g14 generator is 315 MVAr, also it produces 630 MW active power. It is connected to 400 MW P load and 127.4 MVAr Q load. Voltage gradient is almost similar to 4041 bus.
- At minimum load condition, 1432.49 MW power transferred from north to central with the 4042 bus voltage being 1.10 p.u. g14 generator absorbs 50.6 MVAr at this condition to reduce the overvoltage at the 4042 bus terminal.
- When the P transfer is 2927.08 MW in the system, g14 generator hits its Q limit. Since the g14 generator transfers the 630 MW active power produced to the 4042 bus, the Q losses in transformer Tr42-4042 were higher than Q losses in transformer Tr4041-g13. This results in Q measured at HV side of the transformer Tr42-4042 (217.67 MVAr) at Q_{max} limit condition to be lesser than Q produced at g14 terminal (315 MVAr). Voltage at 4042 bus at this point is 1.038 p.u.
- As the g14 generator has hit its Q limit, voltage gradient at 4042 bus increases. At the maximum power transfer condition with P transfer = 3244.84 MW, 4042 bus voltage reaches 0.981 p.u., which is lesser than normal operating voltage (1 p.u.) as

compared to 4041 bus because there is no shunt capacitor connected to 4042 bus, load *tan* ϕ not modified. Also Q from g14 generator reduces to 207.10 MVAr as the load voltage decreases from 1.038 p.u. to 0.981 p.u. The voltage dependent loads draw less power as the voltage decreases.

- Beyond this point of P transfer = 3244.84 MW, 4042 bus voltage decreases rapidly and collapses at 0.743 p.u. for the critical scalable demand of 13834.6 MW (P transfer = 2118.15 MW). Q from g14 generator at this point is 136.98 MVAr.

Table 4.6 gives the P transfer level and corresponding Q support at 4042 bus for the above discusses 4042 bus voltages.

Table 4.6: 4042 bus voltage and corresponding Q from g14

P transfer (MW)	4042 bus voltage (p.u.)	Q from g14 (MVAr)
1432.49	1.10	-50.6
2927.08	1.038	217.67
3244.84	0.981	207.10
2118.15	0.743	136.98

4044 bus - P-V curve

- In Figure 4.2, it can be observed that voltage gradient at 4044 bus is smaller than 4041 and 4042 buses. This can be because 4044 has neither generator nor load connected to it. But the P-V curve pattern of 4044 bus is similar to 4042 bus, g14 generator reactive power support impacts voltage stability at 4044 bus as well.
- At minimum load condition, voltage raises to 1.083 p.u. This voltage level is smaller than the other two buses. No direct Q support available at 4044 bus could be the reason.
- At maximum power transfer condition, bus voltage drops to 0.974 p.u. This is the minimum among the three buses 4041, 4042 and 4044.
- Voltage collapses at 0.696 p.u.

The points are listed in Table 4.7.

Table 4.7: 4044 bus voltage for different P transfer levels

P transfer (MW)	4044 bus voltage (p.u.)
1432.49	1.083
2927.08	1.011
3244.84	0.974
2118.15	0.696

In the following sections, voltage stability at 4041 bus is analyzed for replacing g18 synchronous generator connected to 4063 bus of south sweden with DG using voltage and reactive power control mode at different points.

4.2 Voltage stability assessment at 4041 bus of Central Sweden for different generation mix scenarios

4.2.1 Replacing g18 generator at 4063 bus in south sweden with DG

South sweden has three 400 kV buses 4061, 4062 and 4063. Generator g18 of size 1080 MW is connected to 4063 bus. Q limit of this generator is ±540 MVAr. This generator is connected to 4063 bus through the transformer Tr4063-g18 with reactance 0.15 p.u. In this section, voltage stability at 4041 bus is assessed while replacing this generator with DG of the same MW and MVA size with appropriate transformers to 4063 bus where the g18 synchronous generator was connected. Figure 4.5 shows g18 generator replaced with DG. The network parameters of DG, interconnecting transformers T1, T2, T3 and the 135 kV line are listed in Table 4.8.

Table 4.8: Network parameters of the elements added in the case of DG replacing g18 generator

Element	Parameters
DG	0.69 kV, 1200 MVA, 0.9 PF, Q limit ±540 MVAr (0.5 P_{max})
T1 transformer	400/135 kV, 1200 MVA, R = 0.001 p.u., X = 0.1 p.u.
T2 transformer	135/33 kV, 1200 MVA, X = 0.1 p.u.
T3 transformer	33/0.69 kV, 1200 MVA, X = 0.05 p.u.
135 kV Transmission line	L = 1.1954 mH/km, X/R = 10, C = 0.01 F, Line length: 2 km

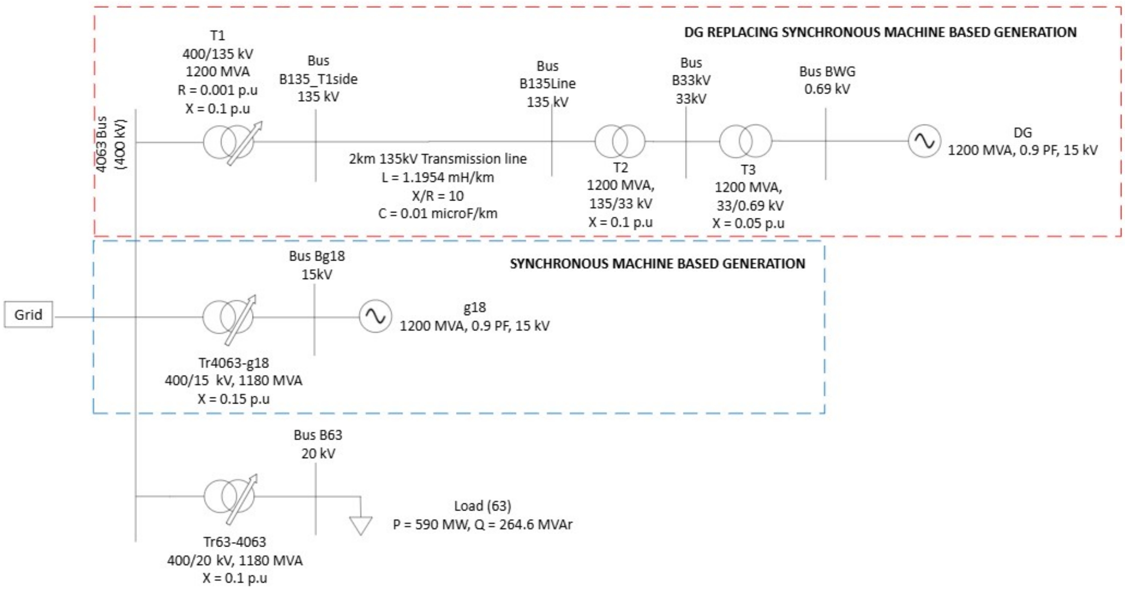

Figure 4.5: DG replacing g18 generator in south sweden

4.2.2 Comparison of P-V curves at 4041 bus for synchronous machine based generation vs DG scenarios

Figure 4.6 gives the comparison of voltage stability at 4041 bus in synchronous machine based generation and replacing one of the generators with DG. In this case, DG terminal voltage is controlled to 1 p.u. Figure 4.8 shows voltage at the DG terminal is controlled to 1 p.u till it hits its Q limit of 540 MVAr.
The maximum P transfer limit has been decreased by 35 MW in DG case. P transfer limit in SG scenario is 3245 MW and DG scenario is 3205 MW only. This is shown in Table 4.9. The decrease in P transfer is due to the increased impedance between DG and 4063 bus. In SG case, the impedance is 0.15 p.u. In DG case, impedance of transformers T1, T2, T3 and 135 kV line(0.048 p.u.) are summed together to 0.298 p.u.

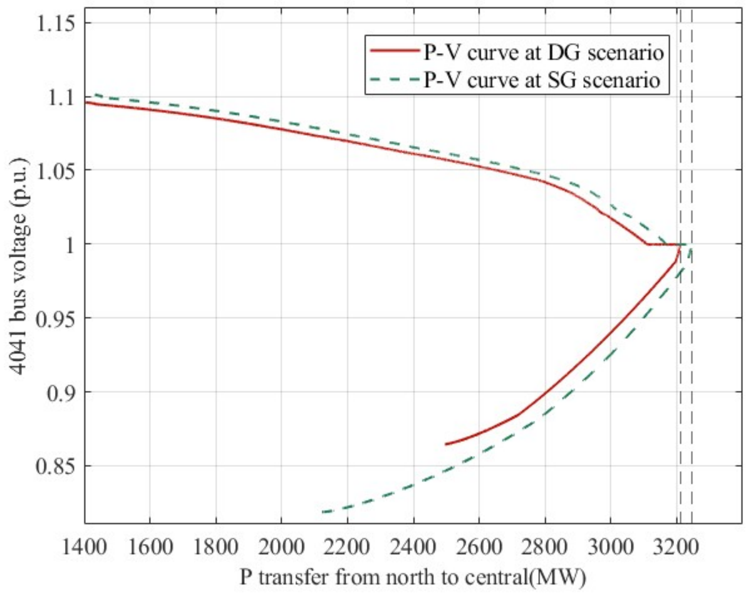

Figure 4.6: P-V curves at 4041 bus for Existing system and replacing g18 generator with DG with their Q support from from g18 and DG respectively

Table 4.9: Maximum power transfer limit in the case of synchronous machine based generation and DG replacing SG

	SG	DG replacing SG	Decrease
P_{max} (MW)	3245	3210	35 (1.078%)

Figure 4.7 shows different Q support available at 4041 bus. The change is Q from south sweden due to DG replacement had caused reduction in P transfer limit. Comparing with the P-V curve in synchronous generator case in Figure 4.3,

- For the same bus voltage at 4041, g13 synchronous generator reaches Q limit at a reduced P transfer limit.
- 4041-capacitor starts to inject reactive power at a earlier P transfer limit.

- Q support obtained from south sweden had reduced in DG case compared to g18 case. This resulted in reduced P transfer limit by 1.078 %. Table 4.10 lists the points mentioned above.

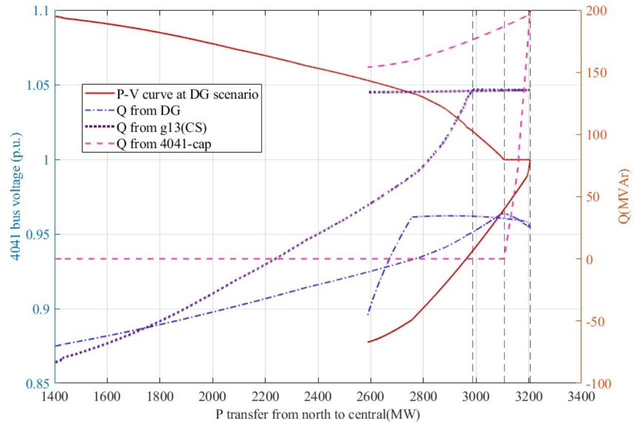

Figure 4.7: P-V curve of 4041 bus and Q support from g13(CS), 4041 capacitor and DG (4063 bus)

P transfer in DG (SG) (MW)	4041 bus voltage (p.u.)	Q from g13 (CS) (MVAr)	Q from 4041-cap (MVAr)	Q from DG (SG) to 4041 bus (MVAr)
2985 (3058.04)	1.019	134.88	0	21.36 (67.62)
3103.45 (3166.62)	1	134.88	1	36.43 (83.96)
3210 (3245)	1	134.88	200	25.36 (78.05)

Table 4.10: P-V curve at 4041 bus - Q support from g13 synchronous condenser, 4041-capacitor and DG

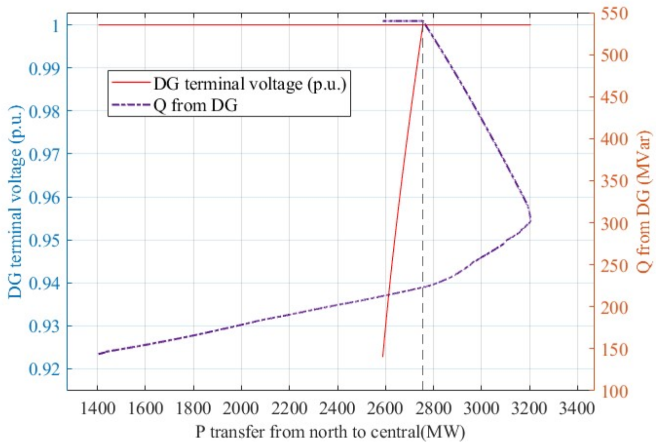

Figure 4.8: DG terminal voltage controlled to 1 p.u until DG reaches its Q limit under Voltage control mode at DG terminal

4.2.3 Controlling 135 kV bus using V control and Q control from DG

It is possible to control the Voltage and Reactive power at a remote point from DG using different control mechanisms. Two control methods are discussed here i.e., V control and Q control at 135 kV bus(named B135Line in Figure 4.5) from DG. The corresponding P-V curves and Q injected by DG in each case are shown in figure 4.9. Table 4.11 lists the P transfer limit in each case and % decrease compared to synchronous machine based generation.

Table 4.11: Maximum power transfer limit in the case of synchronous machine based generation and DG replacing SG

	P_{max} (MW)	Decrease (MW,%)	Q from DG at P_{max} (MVAr)
Synchronous generator case	3245		
DG with V control at its terminal	3205	35 (1.078%)	281.93
DG with V control at 135 kV bus (B135Line)	1971	1274 (39.26%)	321.52
DG with Q control at 135 kV bus (B135Line)	1766	1479 (45.58%)	209.72

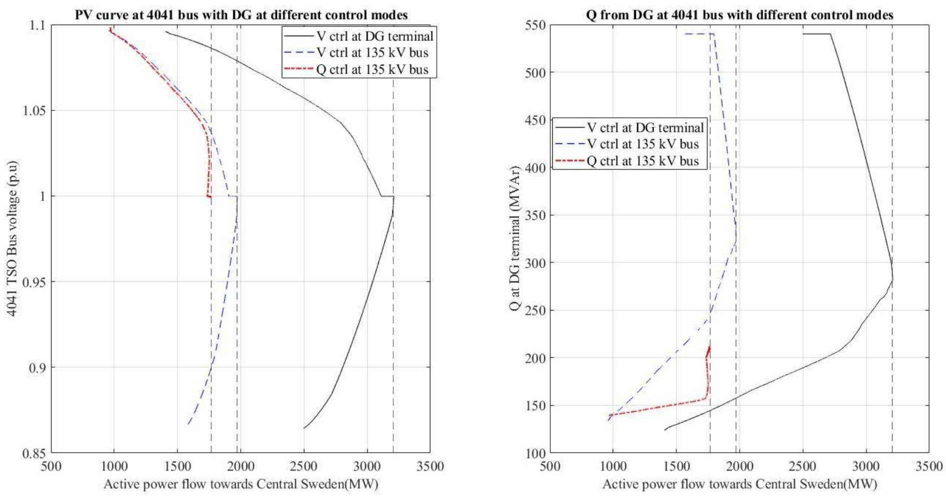

Figure 4.9: left: PV curves at 4041 bus with DG at different control modes; right: Q injected by DG at different control modes

Reduced P transfer limits in voltage and reactive power control mode at B135Line (135 kV bus) from DG

With the voltage control mode at a remote point line B135Line (135 kV bus), Q from DG is primarily utilized to maintain the voltage to 1 p.u. at the set point. It results in higher Q utilization at maximum P transfer point (321.52 MVAr) compared to voltage control at DG terminal (281.93 MVAr at P transfer limit).
At Q control mode, DG tries to control the Q at B135Line (135 kV bus) to zero MVAr

at all operating conditions. This is accomplished by supplying the Q needed by the T2 and T3 transformers between DG and 135 kV bus. When the load is increased, 4041 bus voltage reaches 1 p.u. with Q from DG being 209.72 MVAr. After this point, DG could not supply reactive power to maintain the voltage due to the restriction of the control mode. The Q limit of DG (±540 MVAr) is not fully utilized in Q control mode.

From figure 4.10, it can be verified that

- Voltage at 135 kV bus has been controlled to 1 p.u during V control mode from DG at 135 kV bus. Till DG reaches its Q limit of 540 MVAr, voltage at 135 kV bus is maintained to 1 p.u.
- Q at 135 kV bus has been controlled to 0 MVAr during Q control mode from DG at 135 kV bus.

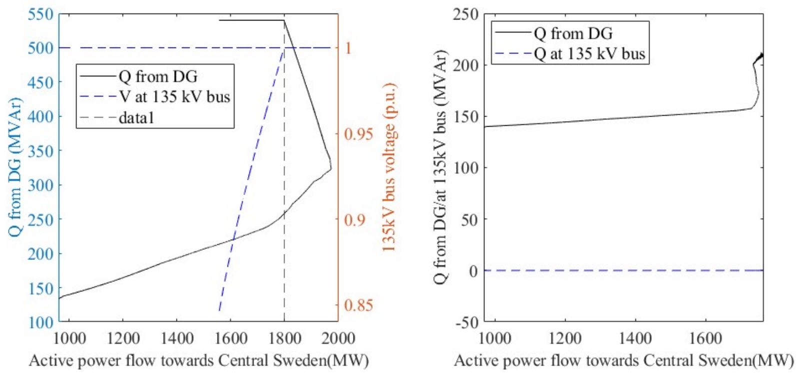

Figure 4.10: left: 135 kV bus voltage controlled to 1 p.u from DG; right: Reactive power at 135 kV bus controlled to 0 MVAr from DG

4.3 Methods to improve maximum power transfer in the case of DG replacing one of the Synchronous generators

It can be seen from the figure 4.6 that the maximum power transfer limit has been reduced by 35 MW in the event of replacing one of the Synchronous generators at South Sweden with DG. While analyzing the voltage stability at 4041 TSO bus located in central sweden, it can be observed that Q limit of DG is not hit at maximum power transfer condition. Since the DG is placed far away from 4041 bus, it is not influencing the voltage of 4041 TSO bus. But still a small decrease in P transfer level is found in the simulation (35 MW).This small deviation can be compensated with the following methods:

- By adding Synchronous Condenser to the TSO bus where the DG is connected
- By increasing the Q limit of DG.
- By increasing the Q limit of g13(CS) connected at 4041 bus.

Figure 4.11 shows how these different compensation methods impact the P transfer limits at 4041 bus.

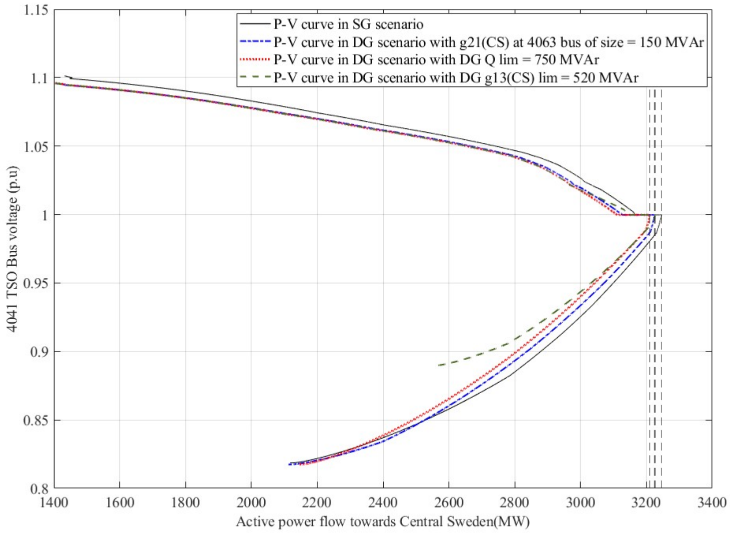

Figure 4.11: Increasing Q_{max} limit of DG to increase the power transfer: P-V curves at 4041 bus in g18 , DG with Q limit same as DG (540 MVAr) and DG Q limit increased to 540 MVAr scenarios.

These methods are discussed in the following sub sections.

Adding Synchronous Condenser at 4063 bus as Q support

- A Synchronous Condenser of size 150 MVAr named g21 is connected to 4063 bus in south sweden where the g18 generator has been replaced with DG. This helps to increase the power transfer limit from north to central Sweden slightly (14 MW).
- Through simulation, it is found that the maximum power transfer limit can not be increased beyond this level in the case of DG replacing g18 generator even though the size of the Synchronous Condenser is increased. Since the g21 synchronous condenser is added far away from 4041 bus, increasing its size is not helping to improve the voltage profile of 4041 bus and P transfer limit from north to central sweden.
- It can also be noted that by adding shunt compensation at the TSO bus 4063, voltage collapse occurs at the same level of total demand in the system in g18(SG) scenario.
- Voltage stability lost at 0.817 p.u., same as synchronous generator scenario.

Increasing Q_{max} limit of DG to increase the maximum power transfer limit

- The Q limit of wind generator is kept as $\pm 0.5P_{max}$. In order to increase the maximum power transfer limit, the Q_{max} limit of the DG can be increased. Through simulations it is found that when the Q_{max} limit of DG was increased from 540 MVAr to 750 MVAr, the critical scalable demand of the system could be increased to 13745.4 MW but the maximum power transfer from north to central sweden did not improve, as it is located far away.

- Since DG is far away from 4041 bus, increasing Q limit is not helping much to improve the P transfer limit.
- Voltage stability lost at 0.817 p.u., same as synchronous generator scenario.

Increasing Q limit of g13(CS) connected to 4041 bus

- In order to improve the voltage profile at 4041 bus, Q limit of the synchronous condenser g13(CS) can be increased. Through simulations it was observed that by increasing its Q limit to 520 MVAr helped to improve the critical scalable demand to 13395.3 MW. Increasing Q limit beyond 520 MVAr did not help to improve the critical scalable demand.
- Further analysis showed that P transfer limit has not improved much with this compensation(only 17 MW increased). Also voltage stability lost in 13395.3 MW load in the system, which is lesser than the other two compensation scenarios (13745.4). Voltage stability lost at 0.89 p.u., earlier compared to the above two compensation methods.

Table 4.12 lists P transfer limit, V_{min} and critical scalable demand in SG, DG with g21(CS) of size 150 MVAr connected at 4063 bus, DG Q limit increased to 750 MVAr and Q limit of g13(CS) connected at 4041 bus increased to 520 MVAr scenarios

Table 4.12: Comparison of different compensation methods in DG scenario to increase the P transfer

	P_{max}(MW)	Voltage collapse point (p.u)	Critical scalable demand (MW)
With SG	3245	0.817	13834.57
DG replacing SG	3210	0.865	12993.5
Increasing Q_{max} of DG to 750 MVAr	3210	0.817	13745.4
Adding 150 MVAr g21(CS) to 4063 bus	3224	0.817	13745.4
Increasing Q_{max} of g13(CS) at 4041bus to 520 MVAr	3227	0.890	13395.3

4.4 Impact of loss of a transmission line on Voltage stability of the system

There are 5 transmission lines connecting North Sweden and Central Sweden viz.,L4031-4041a, L4031-4041b, L4032-4044, L4032-4042 and L4021-4042. Loading of these lines for winter load conditions (given model with load scale factor = 1) is given below:

Line	Loading (MW)
L4031-4041a	663.1
L4031-4041b	663.1
L4032-4044	711.4
L4032-4042	559.1
L4021-4042	625.8

Table 4.13: Line loading in Existing system for load scale factor of 1

It can be seen from the table 4.13 that the line L4032-4044 is the heaviest loaded line among the 5. Loss of this line line causes shift in the current operating point. The shift in the current operating point for Synchronous machine based generation and DG replacing it are discussed in the following sub sections.

4.4.1 N-1 Contingency event in the existing Nordic-32 model

Figure 4.12 shows the operating point in the P-V curve of 4041 TSO bus for a total load on 10500 MW in the system in base scenario with synchronous generator and N-1 contingency scenario with loss one of the transmission lines (L4032-4044). Table 4.14 shows P transfer limit in the case of loss of the heavily loaded line, P transfer limit decreased by 892.72 MW. The current operating point shifted from stable operating region to unstable operating region. The system was not able to be at stable operating region with the loss of the transmission line.

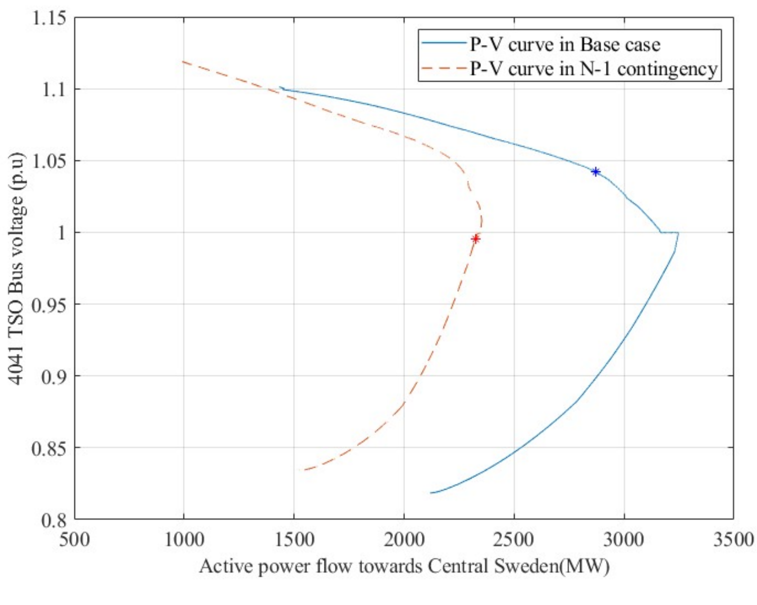

Figure 4.12: Change in operating point for the Existing Model with Synchronous Generation for total load of 10500 MW during loss of one transmission line

Table 4.14: Change in operating point in P-V curve of 4041 bus for N-1 contingency (Loss of a transmission line) in base scenario (synchronous generator case)

	$P_{Operating}$ (MW)	P_{max} (MW)
N-0	2871.76	3245
N-1	2323.3	2352.28

4.4.2 N-1 Contingency event in the case of DG replacing Synchronous Generator

Figure 4.13 shows that for a total system load of 10500 MW in DG scenario, the operating point of 4041 P-V curve shifts from stable operating region to unstable operating region. Table 4.15 shows P transfer limit in DG case decreased by 908.23 MW at N-1 contingency event.

	$P_{Operating}$ (MW)	P_{max} (MW)
N-0	2868.07	3210
N-1	2236.22	2301.77

Table 4.15: Reduction in Stability margin for loss of one transmission line in DG replacing g18 generator

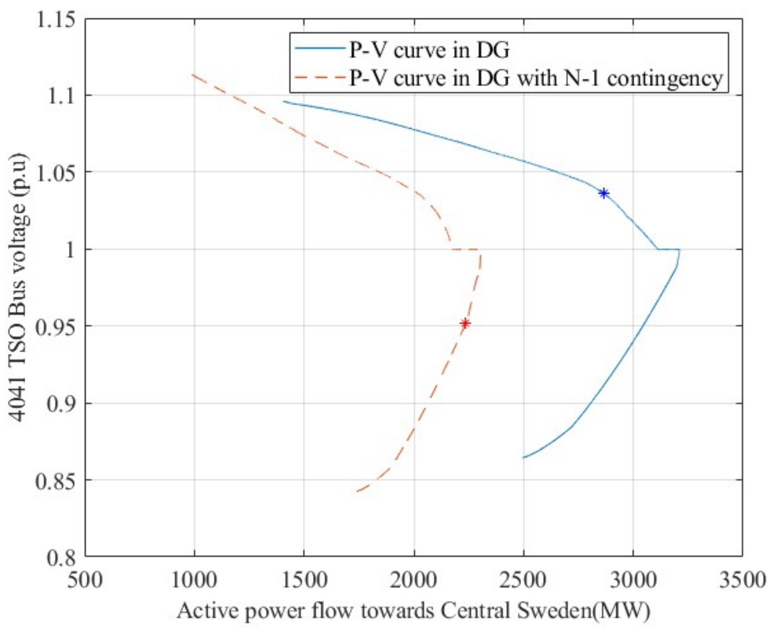

Figure 4.13: Change in operating point for DG replacing g18 generator for total load of 11000 MW during loss of one transmission line

It can be concluded that in both the cases i.e., existing nordic model and DG replacing one of the synchronous generators, voltage stability is lost with loss of L4032-4044 transmission line.

5
Discussion

5.1 Technical discussions

In this Master thesis, impact of utilizing the energy available at south sweden by replacing one of the synchronous generators on voltage stability of TSO buses is discussed. Since the renewable energy sources are scattered and the their installed capacity is comparatively smaller than the centralized synchronous machine based generation, they are usually connected to nearby DSO buses from the cost perspective. Consequently, the impedance between the DG and respective TSO bus becomes higher than in the case of Synchronous Generators connected directly to the TSO bus. Thus, the reactive power from required by TSO bus from DG also increases. Due to the impedance increase between the DG source and the TSO bus, DG hits their Q limit earlier than Synchronous generators. This is discussed in section 4.2. Through simulations, it is found that DG can be connected at a distance of 2 km from the TSO bus of the given Nordic-32 model. For the assumed line parameters, 135 kV line of 2 km length has the impedance of 0.048 p.u. When the length increases, impedance also increases. The nordic-32 model considered was able to be simulated for 2 km length. Power flow was not converging beyond this length.

There are different control modes available with renewable energy integration to the network. Two of them are discussed in this thesis work i.e., voltage control and reactive power control. Also these parameters can be controlled not only at the DG terminal but also at different remote locations with the current technology available. In this thesis work, voltage control at DG terminal is discussed along with voltage and reactive power control at 135 kV bus. When DG is operated with V control at its terminal, the maximum power transfer from north to central sweden is slightly decreased by 35 MW(Figure 4.6). But in the case of controlling V and Q at 135 kV bus terminal, Q from DG is utilized to maintain the control parameters at the designated terminal (Figure 4.10). During voltage control at 135 kV bus terminal, DG supplies Q to maintain the voltage at 135 kV bus to 1 p.u., and during Q control at 135 kV bus DG supplies only the reactive losses in T2 and T3 transformers between DG and 135 kV line in order to maintain the Q at 135 kV bus to zero MVAr. Consequently, P transfer limit is decreased by 39.26% during voltage control mode at 135 kV bus terminal and decreased by 45.58% (Figure 4.9). Also during Q control mode, voltage collapsed even before the Q limit of DG is reached because under Q control mode, 4041 bus voltage was not able to be at stable operating region of P-V curve.

Methods to improve the maximum power transfer limit in DG scenario are discussed

(Figure 4.11. Three methods discussed: adding synchronous condenser to 4063 TSO bus, increasing Q limit of DG and increasing Q limit of synchronous condenser connected to 4041 bus. In all the three methods, P transfer capacity was not able to be improved. 150 MVAr synchronous condenser needed to be added at 4063 bus or DG Q limit was needed to be increased from 540 MVAr to 750 MVAr in order to increase critical scalable demand to 13745.4 MW, nearer to the case of synchronous machine based generation (13834.57 MW). Voltage collapsed at 0.817 p.u. with the help of Q compensation at 4063 bus, similar to synchronous generator case. At 4041 bus, Q limit of g13(CS) was increased to 520 MVAr, even after which the critical scalable demand was not able to be increased beyond 13395.3 MW. While increasing Q compensation at 4041 bus, voltage collapsed at a earlier stage (0.89 p.u.). When the reactive support is far away from target bus, it was found that it is not effective to improve the P transfer limit at the target bus, as in the cases of increasing Q limit of DG and adding g21 synchronous condenser at 4063 bus. But also, increasing Q limit of g13(CS) directly connected at 4041 bus too is not helping to improve the P transfer limit.

But the Q limit is saturated later than the case without reactive compensation. Due to this, voltage stability was observed for the minimum of 0.817 p.u., same as synchronous generator case(Figure **??**). Power flow converges for increase in total load in the system upto 13745.4 MW (13834.57 MW in synchronous generator case).

The impact of loss of one transmission line from north to central sweden in existing system and DG replacement on voltage stability is discussed in this thesis work. Through simulations it is observed that both in existing system and DG replacement scenarios, the operating point shifted to unstable region of P-V curve for the total load of 10500 MW in the system (Figure 4.13 and 4.12).

5.2 Sustainability and ethics

The sustainability aspects of renewable energy based distributed generation (DG) in contemporary power systems span environmental, economic, and social dimensions, reflecting the objectives of the United Nations Sustainable Development Goals (SDGs) [15]. From an environmental standpoint, renewable energy based DG mitigates greenhouse gas emissions and air pollution by reducing dependence on fossil-fuel-based generation, thereby advancing **SDG 7 (Affordable and Clean Energy)** and **SDG 13 (Climate Action)**. Economically, while renewable energy based DG integration can introduce minor voltage stability challenges, it offers notable advantages through reduced operational expenses and the promotion of low-carbon industrial growth. These factors collectively enhance sustainable economic progress and technological innovation, supporting **SDG 8 (Decent Work and Economic Growth)** and **SDG 9 (Industry, Innovation and Infrastructure)**.

Sustainable and ethical strategies for power grids dominated by renewable energy based DG involve integrated technical, environmental, and social considerations. Establishing **grid codes for ethical operation** ensures that voltage and frequency regulation are managed through transparent, fair control mechanisms and that renewable energy based DG actively participate in ancillary services. In addition, **AI governance** frameworks are necessary to guarantee ethical data management, algorithmic transparency, and bias mitigation in automated grid operations. Finally, designing a **resilient and flexible system** that incorporates energy storage, demand response, and hybrid renewable resources enhances voltage stability while reducing emissions, thereby contributing to **SDG 13 (Climate Action)**.

6

Conclusion and Future work

6.1 Conclusions

More and more renewable energy sources are being integrated into the existing network to minimize carbon emissions. Voltage stability is affected when DG are connected far away from the transmission grid.
In the analysis of a 2-bus system with the addition of Q support using a synchronous condenser and a synchronous generator, it is observed that the addition of a synchronous condenser increases the transfer capacity of the network more than the addition of a synchronous generator. The difference is caused by reactive power losses that occurred in the transformers between the synchronous generator and the TSO bus (BB3), as well as the tapped transformer connected to the load. During low-load conditions, it is observed that the excess power produced by the synchronous generator is transferred to the grid. In addition, the overhead line injects reactive power into the system at low load conditions. DG can be integrated into the distribution grid with voltage and reactive power control modes at their terminal or at a remote location. Upon replacing the synchronous generator connected in the 2-bus system with DG using voltage control at its terminal, it is observed that the transfer capacity has been reduced. The increase in impedance between the TSO bus and DG is high compared to the impedance between synchronous generator and the TSO bus. This causes a greater reactive power need from DG for the same load conditions at the start of the simulation. Eventually, the Q limit is reached earlier for DG, causing a reduction in transfer capacity. When the voltage at 135 kV bus is controlled to 1 p.u. from DG, it is observed that the transfer capacity has been reduced. This is because when the voltage at the 135 kV bus needed to be controlled to 1 p.u., the reactive power needed by the transformers in between DG and the 135 kV bus is supplied by DG at minimum load conditions itself. The amount of Q at this point is higher compared to the voltage control at the DG terminal. Also this results in voltage at TSO bus BB3 higher than voltage control at DG terminal mode. In Q control on 135 kV bus, at light load conditions, the injection of reactive power is less from DG, as the overhead line also injects reactive power. From the 2-port network, we can understand that reactive power flows when there is a voltage difference between the two ports. In the Q control mode, Q is controlled to zero, which means that the voltage level at the second port should be higher than that of the Q controlled terminal. If this condition is violated, the power flow does not converge. Due to this, the Q limit of DG is not fully utilized in the case of Q control mode on a remote terminal from DG.

The same scenarios were simulated in Nordic-32 system. When the voltage at a remote

terminal is controlled from DG to 1 p.u., the transfer capacity and voltage at TSO bus 4041 in Central Sweden are worse than the voltage control at the DG terminal. Through simulations, it is observed that during the start of simulation with minimum load conditions, with voltage control mode at DG terminal, DG injects less reactive power than voltage control at 135 kV bus. As the load increases, the reactive power need increases and in the case of voltage control at a remote location from DG, DG attains its Q limit earlier compared to voltage control at its terminal. When reactive power at the 135 kV bus is controlled to zero from DG, through simulations, it is observed that the reactive power capability of DG is not fully utilized to achieve P_{max} transfer from north Sweden. Even before DG attains its Q limit, voltage collapses in the system as in the 2-bus scenario.
This requires more reactive compensation such as synchronous condensers at transmission grid, not only to boost the voltage but also to minimize the over voltage observed at TSO buses during light load conditions. Another way to improve the voltage stability is to increase the reactive power capability of DG but the amount of MVAr required in this case is higher than adding reactive compensation directly at transmission grid. But through simulations, it is observed that increasing reactive power limit of DG does not help to increase the active power transfer limit as the reactive power support is far away from the TSO bus.

More compensation is needed in the Nordic-32 system as the system is not able to withstand N-1 contingency for loss of a transmission line both in synchronous machine-based generation and DG replacing SG scenarios.

6.2 Future works

In this thesis work two control modes of DG are considered, i.e. voltage and reactive power control. Voltage control with droop can be implemented at remote locations, and voltage stability can be assessed as future work.
Constant impedance loads are considered for the load sweep in the simulation. The load characteristics in detail for different load combinations can be analyzed in future work.
Shunt compensation in the form of power electronic interfaces such as STATCOM can be evaluated as future work.

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A

Appendix 1

Total impedance calculation in p.u

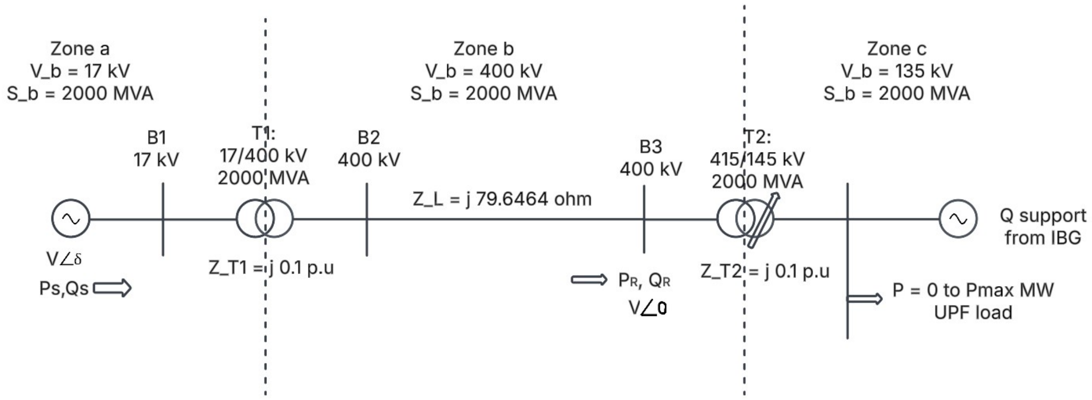

Figure A.1: Total impedance calculation in p.u for a simple lossless system

The given network can be split into three zones with different base voltages, provided that base power is same all through the network.

$$S_B = 2000MVA$$

Base voltages for different zones can be selected according to the voltage ratings of the transformers T1 and T2.

$$V_B^a = 17kV$$
$$V_B^b = 400kV$$
$$V_B^c = \frac{415}{400} \cdot 145 = 139.759kV$$

Base impedance can be calculated from base voltage and base power using the formula

$$Z_B = V_B^2/S_B$$

Thus the base impedance for the different zones are

$$Z_B^a = \frac{(V_B^a)^2}{S_B} = \frac{17^2}{2000} = 0.1445\Omega$$
$$Z_B^b = \frac{(V_B^b)^2}{S_B} = \frac{400^2}{2000} = 80\Omega$$
$$Z_B^c = \frac{(V_B^c)^2}{S_B} = \frac{139.759^2}{2000} = 9.7663\Omega$$

Impedance values of transformers T1 and T2 are given in p.u notation already, Transmission line impedance can be converted into p.u using the following formula

$$\begin{aligned} Z_{line,p.u} &= \frac{Z_{line,actual}}{Z_B^b} \\ &= \frac{j79.6464}{80} = j0.9956p.u \end{aligned}$$

Now, since all the impedance are in p.u, they can be summed up.

$$\begin{aligned} Z_{total} &= Z_{T1} + Z_{line} + Z_{T2} \\ &= j0.1 + j0.9956 + j0.1 \\ &= j1.1956p.u \end{aligned}$$

B

Appendix 2

B.1 Influencing factors for Active and Reactive power flow through a transmission line

Considering a 2 bus system with U_1, P_1 and Q_1 as the sending end voltage, active and reactive powers and U_2, P_2 and Q_2 as the receiving end voltage, active and reactive powers respectively as shown in figure B.1, with the transmission angle Ψ between them and Z being the impedance, 2 port equations to obtain the active and reactive power at sending and receiving endB.1 are given below [10]:

$$\begin{aligned}
P_1 &= \frac{|U_1^2|}{|Z|}\sin\delta + \frac{|U_1||U_2|}{|Z|}\sin(\Psi-\delta)\\
P_2 &= -\frac{|U_2^2|}{|Z|}\sin\delta + \frac{|U_1||U_2|}{|Z|}\sin(\Psi+\delta)\\
Q_1 &= \frac{|U_1^2|}{|Z|}\cos\delta - \frac{|U_1||U_2|}{|Z|}\cos(\Psi-\delta)\\
Q_2 &= -\frac{|U_1^2|}{|Z|}\cos\delta + \frac{|U_1||U_2|}{|Z|}\cos(\Psi+\delta)
\end{aligned} \tag{B.1}$$

where δ being the loss angle $\arctan\frac{R}{X}$

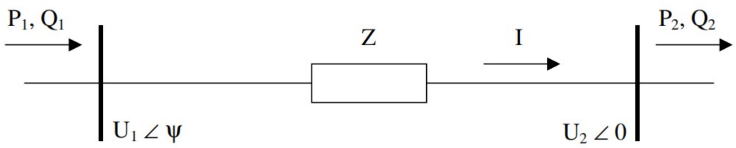

Figure B.1: Representation of 2-bus system

For a lossless line, with the help of 2-port equations the following relations can be obtained.

$$\begin{aligned}
P_1 = P_2 &= \frac{|U_1||U_2|}{|Z|}\sin\Psi\\
Q_1 &= \frac{|U_1|}{|Z|}[|U_1| - |U_2|\cos\Psi]
\end{aligned} \tag{B.2}$$

which implies

- Active power flow is dependent on the transmission angle.

- Reactive power flow is dependent on the voltage difference between sending and receiving ends
  - If $|U_1| > |U_2|$, reactive power at sending end is positive
  - If $|U_1| < |U_2|$, reactive power at sending end is negative

C

Appendix 3

C.1 P-Q Capability diagram of Synchronous Machines vs IBG

C.1.1 P-Q Capability diagram of Synchronous Machines

Reactive power capability limit plays a vital role in Voltage stability assessment. Synchronous Generator P-Q capability diagram is shown in figure C.1. Different limits in the P-Q capability diagram are explained below [8].

- Reactive power output of synchronous generator is limited by armature current, field current and stator end region heating limits.

- Armature current limit refers to the maximum current that can be carried out by the armature without exceeding the heating limit.

  - Armature current limit refers to the circle given by its power ratings $S^2 = P^2 + Q^2$ where S, P and Q refers to apparent power, active power and reactive power respectively.

  - Because of the heating due to power loss in the rotor, field current sets the second limit.

  - Intersection point of armature current and field current limits at the specified power factor gives the operating point of the synchronous generator.

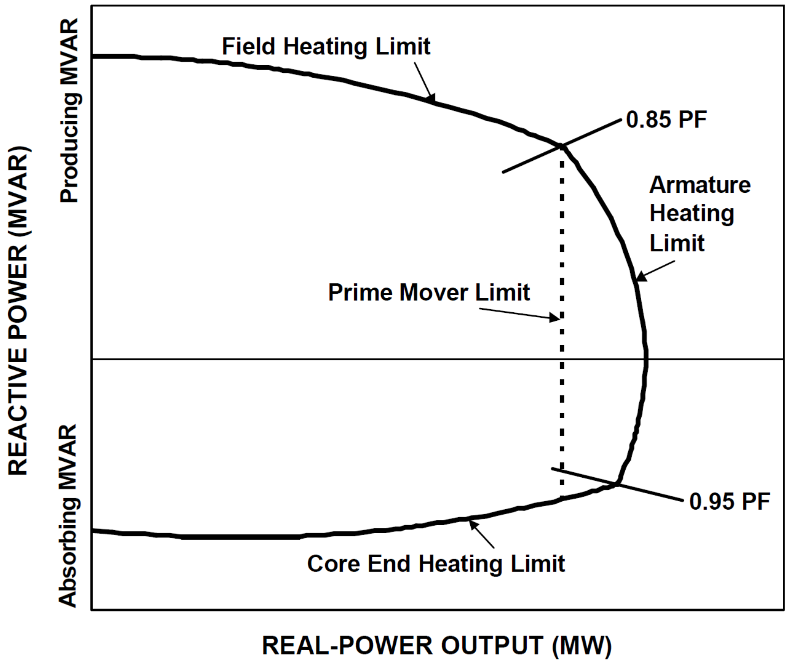

Figure C.1: P-Q Capability Diagram of Synchronous Generator

C.1.2 PQ Capability diagram of Inverter Based Generators

As the output current is limited in the case of inverters, IBG has their operating points within triangular region [9] as indicated in figure C.2 .

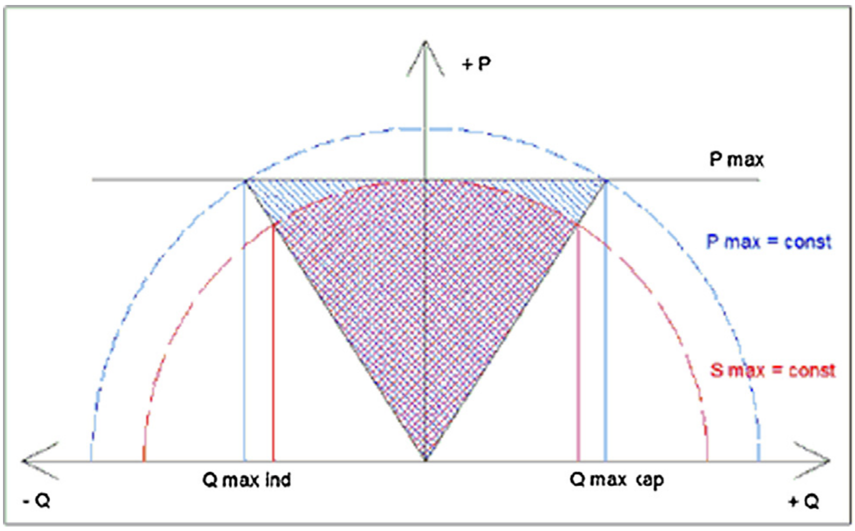

Figure C.2: P-Q capability diagram of inverter

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