iJRASET
International Journal For Research in Applied Science and Engineering Technology

INTERNATIONAL JOURNAL FOR RESEARCH
IN APPLIED SCIENCE & ENGINEERING TECHNOLOGY

Volume: 6 Issue: II Month of publication: February 2018

DOI: http://doi.org/10.22214/ijraset.2018.2019

International Journal for Research in Applied Science & Engineering Technology (IJRASET)
ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 6.887
Volume 6 Issue II February 2018- Available at www.ijraset.com

Evaluation of Nodal Price in Distributed Generation

P. Kripakaran[1], R. Gopi Krishna[2]
[1,2]Department of EEE- Rajiv Gandhi College of Engineering and Technology Puducherry, India.

Abstract: this paper investigates voltage and reactive power control in distribution systems and how the presence of synchronous Machine-based distributed generation (DG) affects the control. A proper coordination among the on load tap changer (OLTC), substation switched capacitors and feeder-switched capacitors in order to obtain optimum voltage and reactive power control is proposed. It is assumed that there is no communication link between the OLTC and the capacitors, a normal case in distribution system operation these days. The results indicate that the proposed method decreases the number of OLTC operations, losses and voltage fluctuations in distribution systems with and without DG present. Further, the nodal pricing for a test system with and without DG also calculated.
Keywords: Capacitor, Distributed generation (DG), On Load Tap Changer (OLTC), Reactive power control, Synchronous machine

I. INTRODUCTION

Voltage regulation and Reactive power (VAR) control are fundamentals in the distribution of electric energy. In fact, voltage regulators and capacitor banks are so common that they are sometimes taken for granted. The voltage collapse phenomenon remains a major issue for power system networks. Voltage collapse may be total (blackout) or partial. Voltage stability is the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance. This project work proposes to study the existing techniques for Voltage and Reactive power control. This paper first investigates voltage and reactive power control in conventional distribution systems by properly coordinating the OLTC, substation switched capacitors (switched capacitors located at the substation secondary bus) and feeder switched capacitors (switched capacitors located anywhere on the feeder) based on an available daily load profile in such a way that the objective function can be reached. The number of tap-changing operations and capacitor switching will be included in the optimization constraints. Second, the impact of DG to the available voltage and reactive power control will be examined. Finally, a proper coordination strategy among DG and other traditional voltage and reactive power control equipment will be presented.

II. VOLTAGE AND REACTIVE POWER CONTROL IN CONVENTIONAL DISTRIBUTION SYSTEMS

A transformer equipped with a load tap changer (LTC) can adjust its voltage ratio with respect to the present or expected load, to compensate the voltage drop over the transformer and upstream lines. The representation of a transformer equipping an LTC and its equivalent diagram are shown in Fig..1

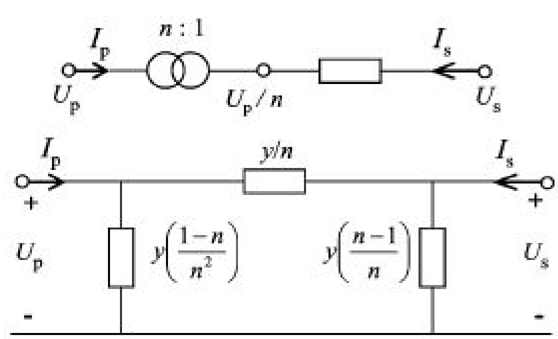


Fig. 1 LTC representation and its equivalent diagram

where notation I, U, n, and y indicate current, voltage, normalization of the transformers turn ratio and transformer admittance, respectively; and subscripts p and s indicate the primary and secondary sides of the transformer respectively.

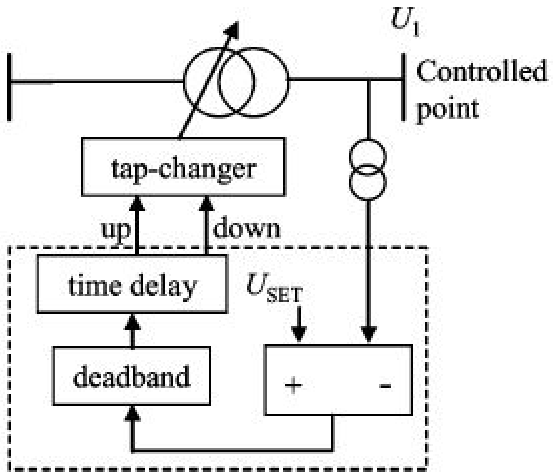


Fig.2 Basic OLTC arrangement

The OLTC basic arrangement is shown in Fig. 2 above. The OLTC controller keeps the substation secondary bus voltage U1 constant within the range

$$U_{LB} \leq U_1 \leq U_{UB} \tag{1}$$

Where,

$U_{LB} = U_{set} - 0.5\,U_{DB}$	lower boundary voltage
$U_{UB} = U_{set} + 0.5U_{DB}$	upper boundary voltage
U_{set}	set point voltage
U_{DB}	dead band voltage

III. TEST SYSTEM

The voltage and reactive power control are tested on a test system includes a 10-kV transmission system and a 70-kV distribution system. DGs are of synchronous generator type connected at buses 3 and 10.

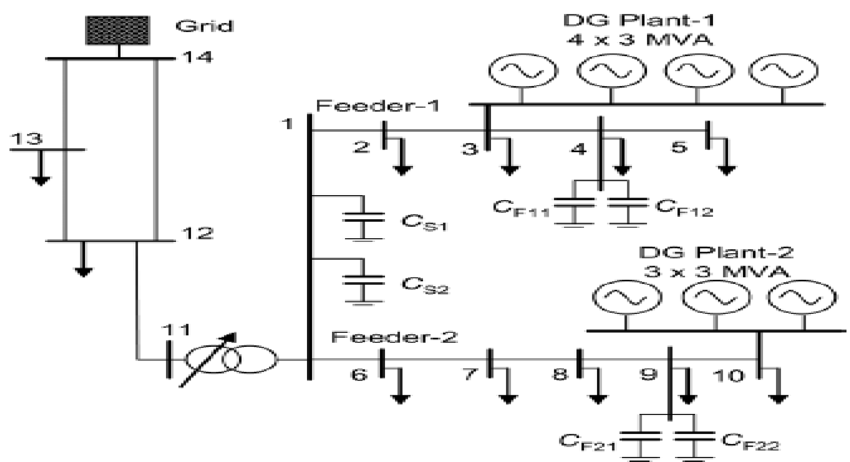


Fig.3 One line diagram of the test system

A. Different modes of operation

Three different cases are investigated.

1) Case 1: without DG

International Journal for Research in Applied Science & Engineering Technology (IJRASET)
ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 6.887
Volume 6 Issue II February 2018- Available at www.ijraset.com

2) Case 2: with DG operated at a unity pf
3) Case 3: with DG generating constant reactive power

In order to obtain a direct comparison of the effect of the different operating modes of DG on the losses, the DG is set to generate constant active power in all cases. The DG is set to operate with constant voltage and to have reactive power capability between 0.95 lagging pf and 0.95 leading pf for case-3.

In order to obtain a direct comparison of the effect of the different DG operating modes on the losses , the DG is set to generate constant active power Pg = 2.97 in all cases. These values are not selected based on the common DG reactive power capability but on getting a sense as to how a low amount of DG reactive power contributes to the voltage and reactive power control.

Thus the simulation of the system under different modes of operation, investigates voltage and reactive power control in distribution systems and how the presence of synchronous machine-based distributed generation (DG) affects the control.

The model of the system under test, its description, simulation and the experimental results are discussed below in detail. The graphs and tables presented will help in analysing the different cases of investigation. They validate the advantage of the proposed method.

B. Without DG (Case 1)

This case includes the simulation of the test system without including DG. This case can be investigated using the ETAP software and the results are obtained. These results are then used to compare with the other cases of investigation in order to validate the advantage of the proposed method.

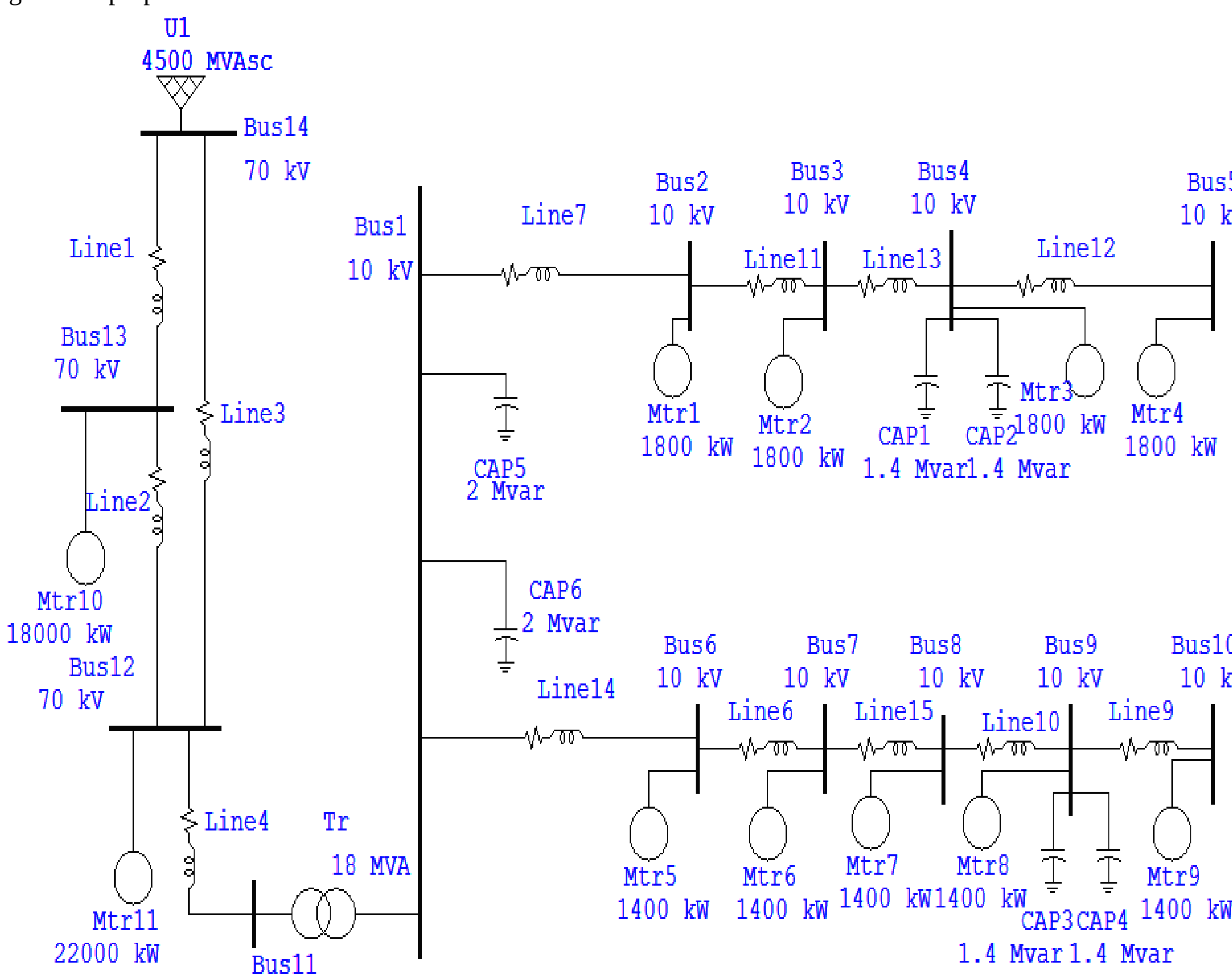


Fig.4 System without DG

C. With DG operated at a unity pf (Case 2)

This case includes the simulation of the test system including DG plant. The DG systems are introduced at buses 3 and 10. The plants are of 4 × 3 MVA at bus no. 3 and 3 × 3 MVA at bus no.10. The DG plant is set to operate at unity power factor.

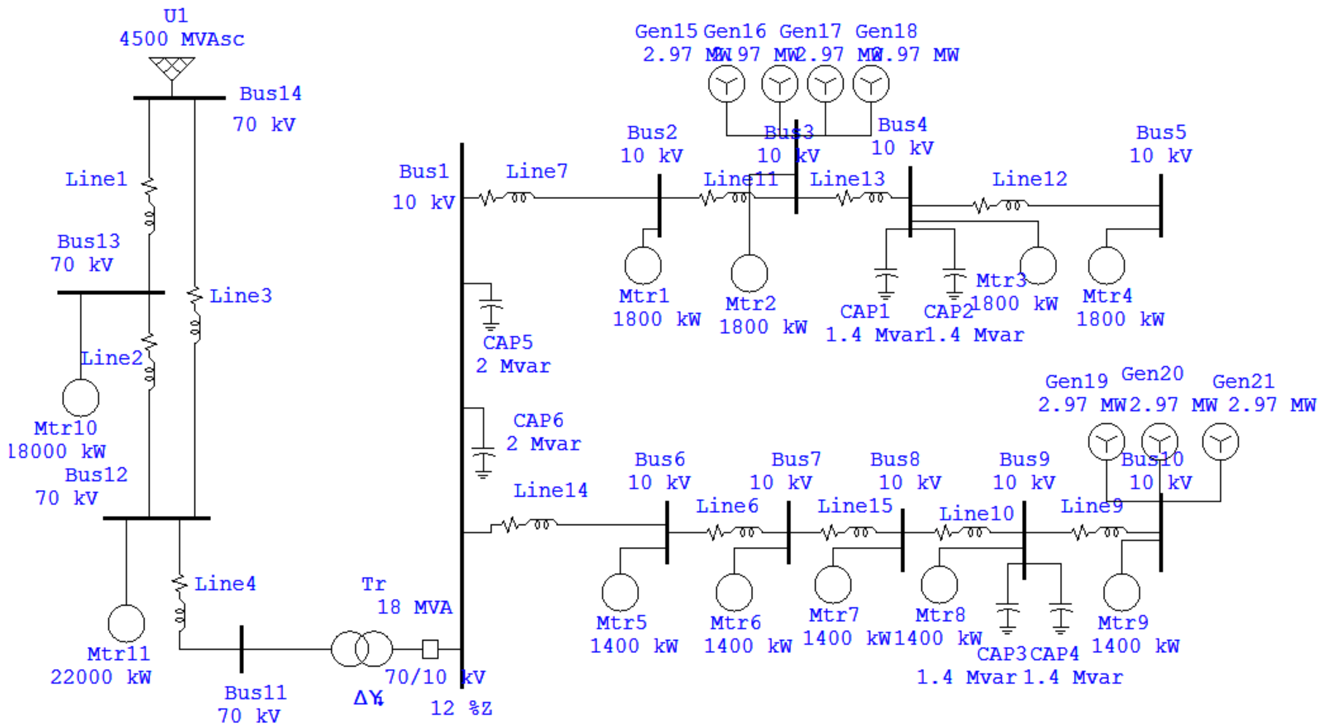


Fig 5 System including DG

D. With DG generating constant reactive power (Case 3)

The system is set to operate at 0.95 lagging power factor, at a constant voltage and with a reactive power limits. The active power Pg is set to be 2.97 Mw as in all cases in order to obtain a direct comparison of the effect of the different DG operating modes on the losses.

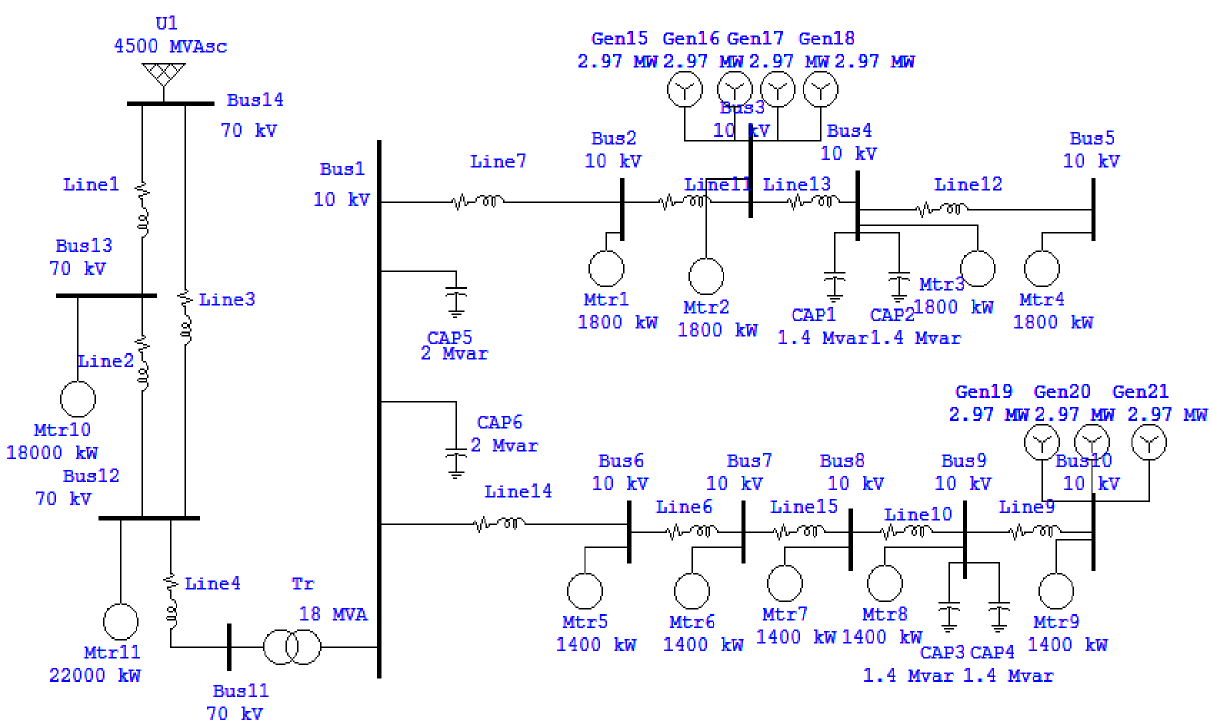


Fig. 6 System including DG operating at specified reactive power limits

E. Simulation results

Table 1 shows the bus loading in each of the buses for all the three cases for a particular time interval of 0.00 hrs

BUS No	CASE 1	CASE 2	CASE 3
Bus 1	15.525	15.511	15.481
Bus 2	7.738	7.744	7.730
Bus 3	5.766	5.764	5.765
Bus 4	3.828	3.828	3.828
Bus 5	1.914	1.914	1.914
Bus 6	7.573	7.589	7.564
Bus 7	6.018	6.042	6.016
Bus 8	4.493	4.512	4.494
Bus 9	2.987	2.990	2.985
Bus 10	1.491	1.491	1.491
Bus 11	15.681	15.690	15.633
Bus 12	38.885	38.887	38.525
Bus 13	32.676	32.650	32.636
Bus 14	58.546	58.484	58.458

Table 1 Bus loading

Table 2 shows the comparison of load flow in all the buses for all the three cases for a particular time interval of 0.00 hrs

BUS ID		CASE 1		CASE 2		CASE 3	
FROM	TO	MW	MVAR	MW	MVAR	MW	MVAR
BUS 1	BUS 2	7.847	3.778	7.84	-1.68	7.82	1.94
BUS 1	BUS 6	7.678	3.772	7.67	0.42	7.66	2.32
BUS 1	BUS11	-15.525	-3.550	-15.51	5.24	-15.48	-0.28
BUS 2	BUS 1	-7.738	-3.460	-7.74	1.95	-7.73	-1.67

BUS 2	BUS 3	5.824	2.024	5.83	-3.39	5.82	0.23
BUS 3	BUS 2	-5.766	-1.856	-5.76	3.58	-5.77	-0.09
BUS 3	BUS 4	3.852	0.420	3.85	0.17	3.85	0.34
BUS 4	BUS 3	-3.828	-0.351	-3.83	-0.11	-3.83	-0.28
BUS 4	BUS 5	1.914	1.436	1.91	1.44	1.91	1.44
BUS 5	BUS 4	-1.91	-1.436	-1.91	-1.44	-1.91	-1.44
BUS 6	BUS 1	-7.573	-3.465	-7.59	-0.17	-7.56	-2.05
BUS 6	BUS 7	6.082	2.347	6.10	-0.95	6.07	0.93
BUS 7	BUS 6	-6.018	-2.159	-6.04	1.11	-6.02	-0.76
BUS 7	BUS 8	4.527	1.040	4.55	-2.23	4.53	-0.35
BUS 8	BUS 7	-4.493	-0.941	-4.51	2.34	-4.49	0.45
BUS 8	BUS 9	3.002	-0.177	3.02	-3.46	3.00	-1.56
BUS 9	BUS 8	-2.987	0.220	-2.99	3.55	-2.99	1.62
BUS 9	BUS 10	1.497	1.135	-1.50	-1.90	1.49	-0.14
BUS 10	BUS 9	-1.491	-1.118	-1.49	1.93	-1.49	0.15
BUS 11	BUS 12	-15.681	-5.109	-15.69	3.45	-15.63	-1.80
BUS 11	BUS 1	15.981	5.109	15.69	-3.45	15.63	1.80
BUS 12	BUS 13	-13.720	-4.678	-13.70	-0.52	-13.68	-3.06
BUS 12	BUS 14	-25.165	-8.327	-25.19	-3.91	-25.14	-6.61
BUS 12	BUS 11	15.771	5.409	15.77	-3.17	15.71	2.07
BUS 13	BUS 14	-25.165	-11.072	-32.65	-6.89	-32.64	-9.77
BUS 13	BUS 12	13.775	4.860	13.75	0.68	13.73	3.23
BUS 14	BUS 13	33.018	12.210	32.97	7.94	32.97	10.54
BUS 14	BUS 12	25.529	9.540	25.52	5.01	25.49	7.77

International Journal for Research in Applied Science & Engineering Technology (IJRASET)
ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 6.887
Volume 6 Issue II February 2018- Available at www.ijraset.com

Table 2 Load flow report

Table 3 shows the comparison of branch loses in all the buses for all the three cases for a particular time interval of 0.00 hrs.

LINE No	CASE 1	CASE 2	CASE 3
Line 1	341.4	316.8	330.0
Line 2	54.4	47.9	50.6
Line 3	363.8	5.764	5.765
Line 4	90.0	82.5	80.8
Line 5	109.2	93.0	93.9
Line 6	57.8	66.3	50.9
Line 7	23.6	21.4	22.9
Line 8	0.0	0.0	0.0
Line 9	105.4	85.5	92.5
Line 10	64.6	56.5	56.9
Line 11	34.1	38.5	31.9
Line 12	14.6	31.4	17.9
Line 13	5.8	8.6	3.5
Line 14	155.8	178.7	152.1

Table 3 Branch losses

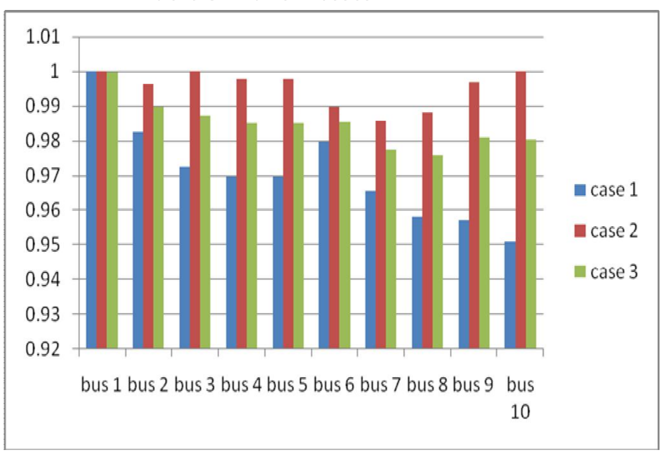


Fig 7 shows the comparison of voltage fluctuation in each of the buses for all the three cases for a particular time interval of 0.00 hrs

ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 6.887
Volume 6 Issue II February 2018- Available at www.ijraset.com

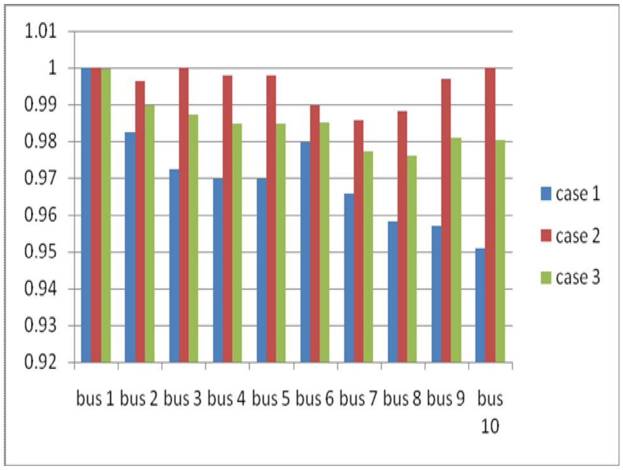


Fig 8 shows the comparison of voltage fluctuation in each of the buses for all the three cases for a particular time interval of 6.00 hrs

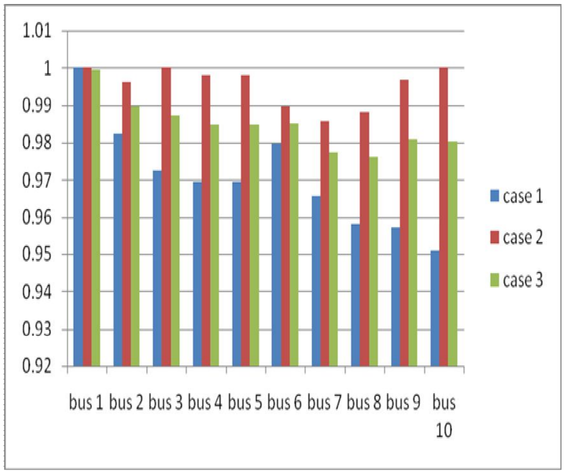


Fig 9 shows the comparison of voltage fluctuation in each of the buses for all the three cases for a particular time interval of 13.00 hrs

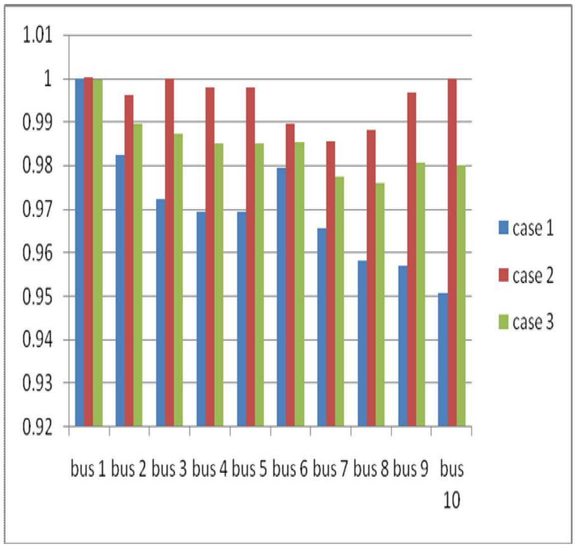


Fig 10 shows the comparison of voltage fluctuation in each of the buses for all the three cases for a particular time interval of 20.00 hrs

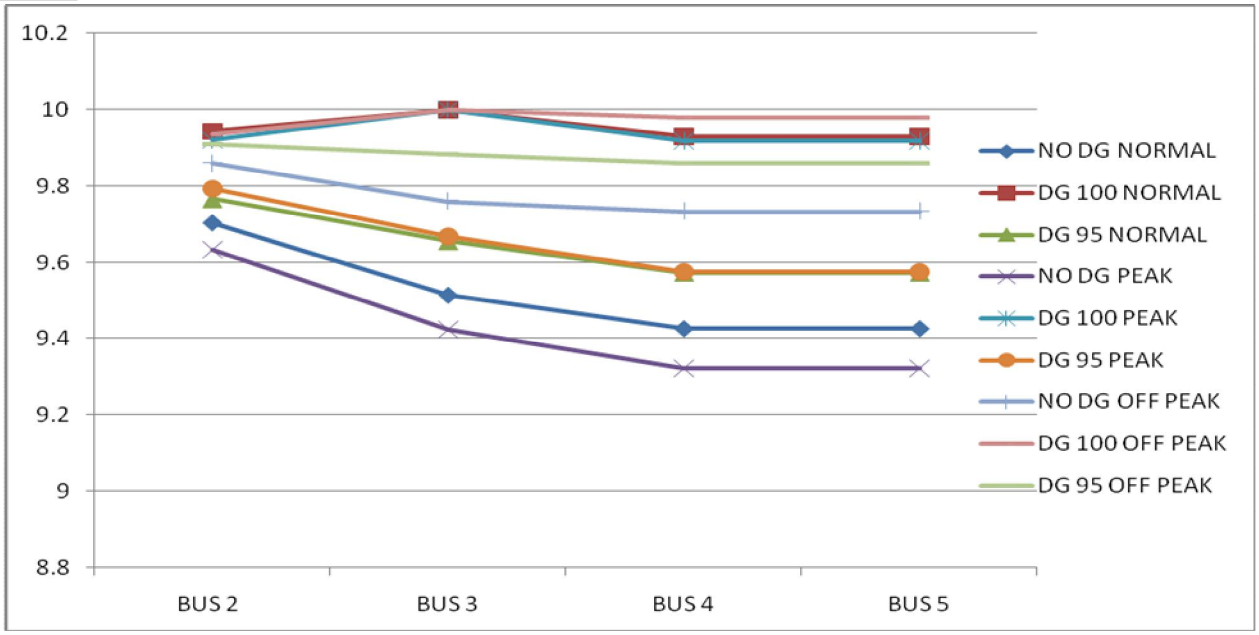


Fig 11 Voltage Profile for all buses with and without DG

IV. PRICING METHODS

The transmission will facilitate a competitive electricity market by impartially providing energy transportation services to all energy buyers and sellers, while fairly recovering the cost of providing those services. For cost recovery the customers (generators/loads) have to be charged a price, which has to be defined clearly to allow correct economic and engineering decisions on upgrading and expanding generation, transmission and distribution facilities. Nodal Pricing is a method of determining prices in which market clearing prices are calculated for a number of locations on the transmission grid called nodes. Each node represents the physical location on the transmission system where energy is injected by generators or withdrawn by loads. Price at each node represents the location value of energy, which includes the cost of the energy and the cost of delivering it, i.e., losses and congestion. Thus, the pricing should meet the following requirements:

Promote economic efficiency

Compensate grid companies fairly for providing transmission services

Allocate transmission costs reasonably among all transmission users, both native load and third party

Maintain the reliability of the transmission grid

A. Nodal Price Calculation

Let λ= penalty factor

P_{kg} = Active power injected by generator g, at bus k.

Q_{kg}= Reactive power injected by generator g, at bus k.

P_{kd}= Active power consumed by demand d, at bus k.

Q_{kd} =Reactive power consumed by demand d, at bus k.

$C_{kg}(P_{kg}, Q_{kg})$= Total cost of producing active and reactive power.

P_{kt} = Net withdrawal position for active power at each bus k, at time t.

Q_{kt} = Net withdrawal position for reactive power at each bus k, at time t.

P_{kgt} = Active power injected by generator g, at bus k at time t.

P_{kdt} = Active power consumed by demand d, at bus k at time t.

Least cost dispatch at time t,

International Journal for Research in Applied Science & Engineering Technology (IJRASET)
ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 6.887
Volume 6 Issue II February 2018- Available at www.ijraset.com

$$\lambda = \min_{\substack{P_{kgt}, Q_{kgt} \\ \forall kg, kd}} \sum_k \sum_g C_{kg}(P_{kgt}, Q_{kgt}) \quad (2)$$

$$\lambda = a_k P^2_{gk} + b_k P_{gk} + c_k \quad (3)$$

where, a_k =0.14, b_k =20.4, c_k=5

subject to,

$$\text{Loss}(P,Q) - \sum_k \sum_g P_{kgt} + \sum_k \sum_d P_{kdt} = 0, \quad \text{for all t.} \quad (4)$$

$$P_{kt} = \sum_d P_{kdt} - \sum_g P_{kgt} \quad (5)$$

$$Q_{kt} = \sum_d Q_{kdt} - \sum_g Q_{kgt} \quad (6)$$

Nodal price for active and reactive power,

$$P_{akt} = \lambda \ (1+\text{loss}/P_{kt}), \ Q_{rkt} = \lambda \ (1+\text{loss}/Q_{kt}) \quad (7)$$

B. Test System

Consider the test system with only one feeder as shown below:

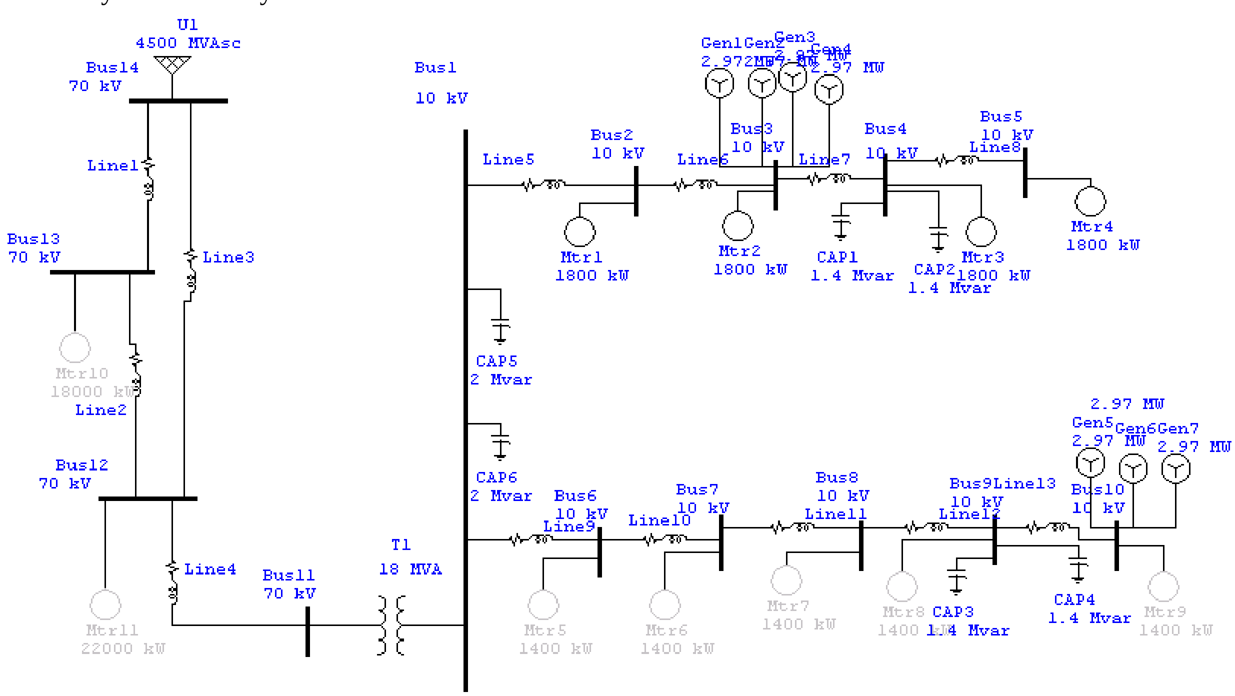


Fig 12 System considered for nodal pricing

International Journal for Research in Applied Science & Engineering Technology (IJRASET)
ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 6.887
Volume 6 Issue II February 2018- Available at www.ijraset.com

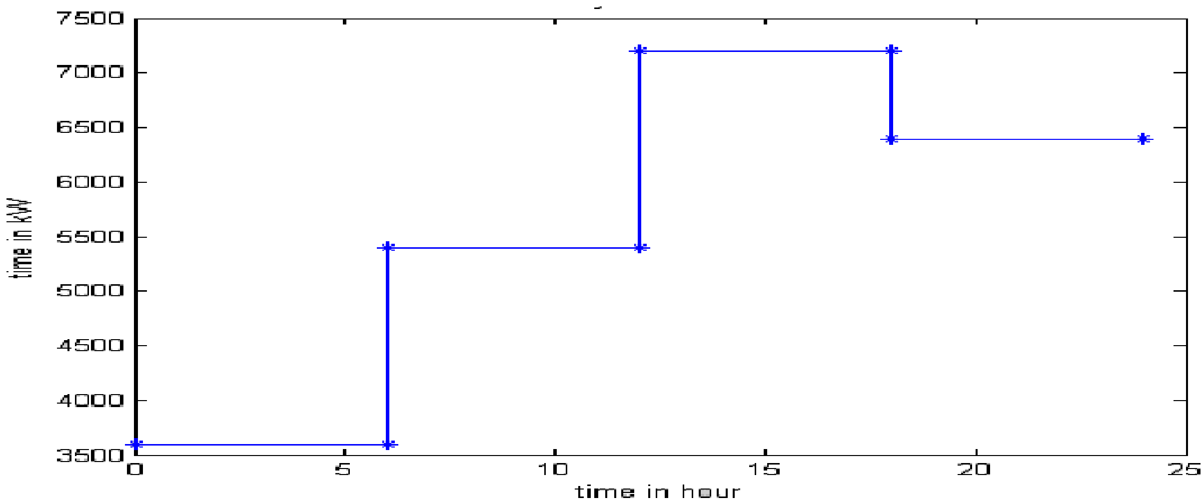


Fig 13. Daily Load curve

Timing	Load	Pricing(Rs/MWhr)	
		Without DG	With DG
Off peak(0-6hrs)	3.6MW	24.536	23.178
Peak(6-13hrs)	7.2MW	27.734	26.752
Shoulder day(13-20hrs)	6.4MW	26.375	25.477
Shoulder night (20-24hrs)	5.4MW	25.226	24.202

Tab 4 Load profile and pricing

V. CONCLUSION

In this project, voltage and reactive power control in a distribution system has been studied and also the nodal price for a system is evaluated with DG and without DG. A proper coordination among an OLTC, substation-switched capacitors, feeder switched capacitors, and synchronous machine-based DG, without requiring communication among them has been presented. The DG evaluated in the case study is of the synchronous machine-based DG. It has been demonstrated that the power-flow reversal due to the DG will not interfere with the effectiveness of the OLTC operation. The presence of the DG, with despicable power output, even decreases the voltage fluctuation and significantly decreases the number of OLTC operations in the system. Finally, it has been shown that when the feeder capacitors available in the feeder are enough to compensate for the reactive power demand, the DG operation mode does not have a significant effect on the distribution system losses. But the number of OLTC operations and the voltage fluctuation in the system will be reduced significantly when the DG operates at a constant voltage. These significant reductions will benefit the distribution network operator and customers. The project also present the nodal pricing scheme applied to distribution networks with distributed generation (DG). It is clear that a DG resource when properly located it can provide benefits to the network through reduced line losses and line loading. We contend that DG resources should be appropriately rewarded,

International Journal for Research in Applied Science & Engineering Technology (IJRASET)
ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 6.887
Volume 6 Issue II February 2018- Available at www.ijraset.com

through nodal pricing, for providing such benefits to the distribution system. Also the price impact of losses without the DG resource and then the reduction in prices with the DG resource is dealt. Given worldwide experience with nodal pricing, and the fact that DG resources transform the distribution network into an active network like transmission, it makes sense to consider nodal pricing in distribution.

REFERENCES

[1] Timothy J. McCoy, "Trends in Ship Electric Propulsion," IEEE, vol I pp. 343- 346, 2012.
[2] Wang, Z. Liu, Y., "Modeling and simulation a cyclo converter drive system for harmonic studies;' IEEE Transactions on Industrial Electronics, Vo1.47, No.3, pp.533-541, 2000.
[3] ABB Company ltd, "Maritime Electrical Installations and Diesel Electric Propulsion", 04.12, 2003.
[4] J. V. Amy, Jr., "Considerations in the Design of Naval Electric Power Systems", 2002 IEEE Power Engineering Society Summer Meeting, vol.I, pp.330-335, 2002.
[5] D. H. Clayton, S. D. Sudhoff, and G. F. Grater, "Electric Ship Drive and Power System", Conference Record of the 2004 24th International Power Modulation Symposium, pp.85-88, 2000.
[6] E. J. Lecourt, "Using Simulation to Determine the Maneuvering performance of the WAGB-20", Naval Engineers Journal, pp.171-188, January 2008.
[7] S. Woodruff, "Real Time Digital Harmonic Modeling and Simulation an Advanced Tool for Understanding Power System Harmonic Mechanisms". IEEE Power Engineering Society General Meeting, vol I, pp.773-776, 6-10 June 2010
[8] Kalsi, Swam S. and Om Nayak, "Ship Electrical System Simulation", IEEE Electric Ship Technologies Symposium, pp.63-69, 25-27 July 2011.
[9] R. E. Hebner, "Electric Ship Power System-Research at the University of Texas at Austin", IEEE Electric Ship Technologies Symposium, pp.34-38, 25-27 July 2013.

APPENDIX

A. *Specification Of The Test System*

Transmission lines

r = 0.15 Ω/km,
x = 0.5 Ω/ km,
I rated = 500 A,
Line length 11–12: 10 km;
Line length 12–13: 8 km;
Line length 12–14: 16 km;
Line length 13–14: 9 km;

Distribution lines

r = 0.12 Ω/km,
x = 0.35 Ω/ km,
i,rated = 610 A,

Feeder length 1: 1.2 km

Feeder length 2: 1.2 km
Distance between two buses: 1 km

Loads

At bus 12 : 22 MW with 0.95 pf
At bus 13: 18 MW with 0.95 pf,
Under feeder 1: 1.8 MW with 0.8 pf
Under feeder 2: 1.4 MW with 0.8 pf.

Transformer

Transmission side 70 kv
Distribution side 10 kv
MVA rating 18 MVA
x = 12%
x/r = 10
OLTC at HV side
Regulation : -10% to 10%

Steps : 32 steps.

Distributed Generators (DG)

S = 3 MVA;

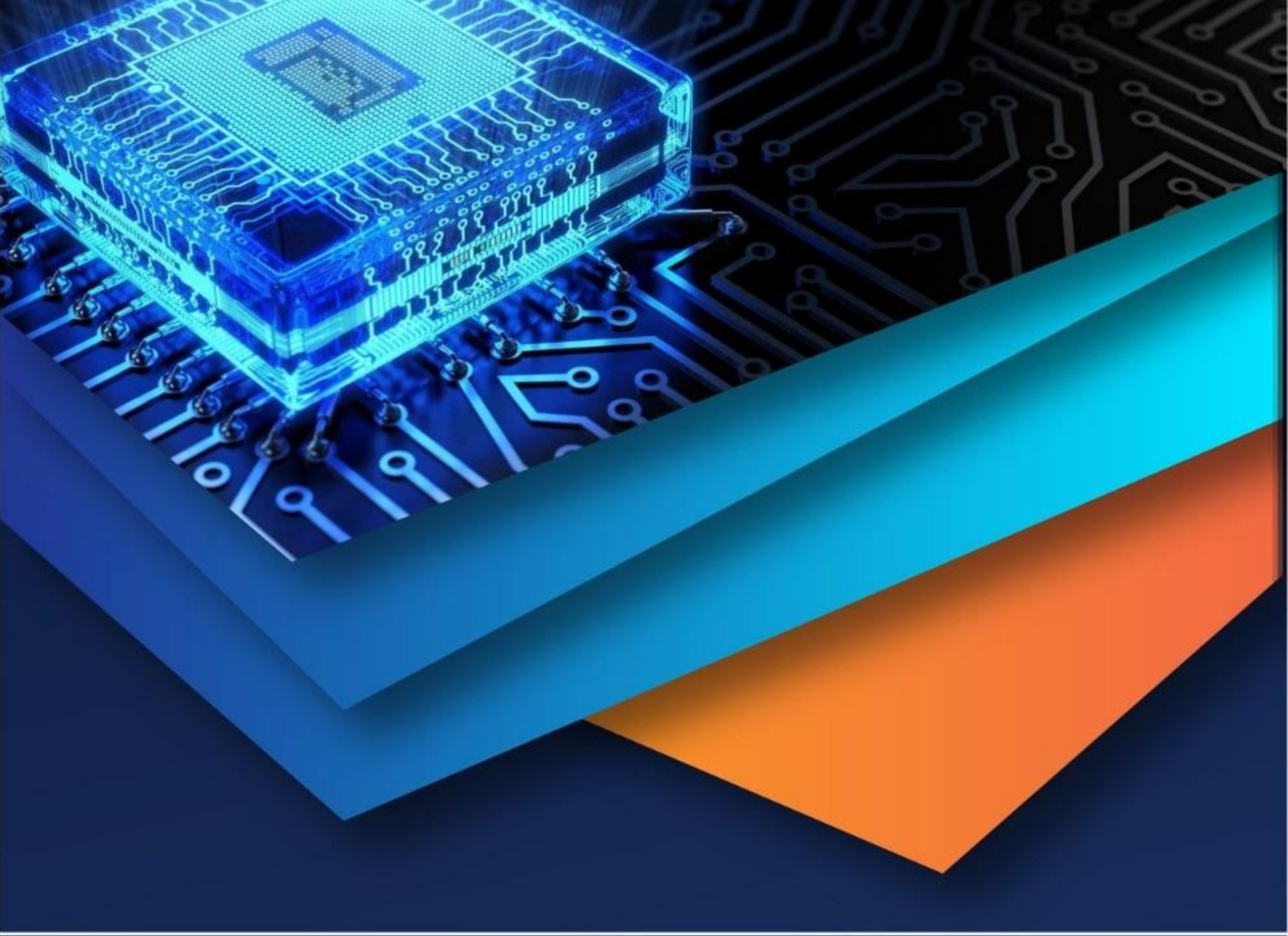
Qgmin = -0.423 Mvar;

Qgmax = 0.423 Mvar.

Capacitors

Substation capacitors: 2 Mvar each.

Feeder capacitors: 1.4 Mvar each.



10.22214/IJRASET

45.98

IMPACT FACTOR: 7.129

IMPACT FACTOR: 7.429

INTERNATIONAL JOURNAL FOR RESEARCH

IN APPLIED SCIENCE & ENGINEERING TECHNOLOGY