Question 1

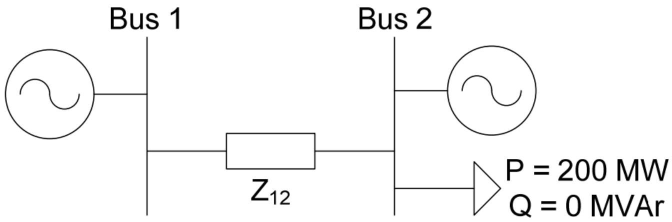

Fig 1. Two-bus network

Cost functions are defined as:

$$C_1(P_1) = 20P_1^2 + 700P_1 + 1000$$
$$C_2(P_2) = 20P_2^2 + 700P_2 + 1000$$

By taking transmission losses into consideration, from the full power balance:

$$P_D + P_{loss} = P_1 + P_2$$

the loss are approximated as $P_{loss} = 0.1P_1^2$:

the equality constraint are defined as:

$$\varphi = P_D + 0.1P_1^2 - P_1 - P_2 = 0$$

Applying LaGrange function:

$$L = C_1(P_1) + C_2(P_2) + \lambda(P_D + 0.1P_1^2 - P_1 - P_2)$$

Taking Partial derivative to find local minima:

$$\begin{cases} \dfrac{\partial L}{\partial P_1} = \dfrac{dC_1(P_1)}{dP_1} + \lambda\left(\dfrac{\partial P_{loss}}{\partial P_1} - 1\right) = 700 + 40P_1 + \lambda(0.2P_1 - 1) = 0 \\ \dfrac{\partial L}{\partial P_2} = \dfrac{dC_2(P_2)}{dP_2} + \lambda\left(\dfrac{\partial P_{loss}}{\partial P_2} - 1\right) = 700 + 40P_2 + \lambda(0 - 1) = 0 \\ \dfrac{\partial L}{\partial \lambda} = P_D + 0.1P_1^2 - P_1 - P_2 = P_D + 0.1P_1^2 - P_1 - P_2 = 0 \end{cases}$$

Power demand is written as :

$$P_D = -P_{loss} + \sum_{i=1}^{n} P_i = f(\lambda)$$

Using Taylor's series expansion, power demand is written as:

$$f(\lambda)^{(k)} + \left(\frac{df(\lambda)}{d\lambda}\right)^{(k)} \Delta\lambda^{(k)} = P_D$$

$$\Delta\lambda^{(k)} = \frac{P_D - f(\lambda)^{(k)}}{\left(\frac{df(\lambda)}{d\lambda}\right)^{(k)}} = \frac{\Delta {P_D}^{(k)}}{\left(\frac{df(\lambda)}{d\lambda}\right)^{(k)}}$$

$$\lambda^{(k+1)} = \lambda^{(k)} + \Delta\lambda^{(k)}$$

From Fig 1, we can know that:

$$P_D = \frac{\sqrt{200^2 + 0^2}\,MVA}{100\,MVA} = 2\,pu$$

Rearrange the equations:

$$\begin{cases} P_1 = \dfrac{\lambda - 700}{0.2\lambda + 40} \\ P_2 = \dfrac{\lambda - 700}{40} \\ P_D = P_1 + P_2 - 0.1P_1^2 = f(\lambda) \end{cases}$$

note:

$$f(\lambda) = \frac{\lambda - 700}{0.2\lambda + 40} + \frac{\lambda - 700}{40} - 0.1\left(\frac{\lambda - 700}{0.2\lambda + 40}\right)^2$$

$$\frac{df(\lambda)}{d\lambda} = \frac{\lambda^3 + 600\lambda^2 + 120000\lambda + 170000000}{40(\lambda + 200)^3}$$

1. Make initial estimate of system marginal cost:

$$\lambda^{(1)} = \frac{dC(P)}{dP}|_{P=1} == 700 + 2 \times 20 \times 1 = 740$$

2. Use $\lambda^{(1)}$ to calculate $P_i^{(1)}$and $P_{loss}^{(1)}$

$$\begin{cases} P_1^{(1)} = \dfrac{\lambda^{(1)} - 700}{0.2\lambda^{(1)} + 40} = \dfrac{740 - 700}{0.2 \times 740 + 40} = 0.212765957 \\ P_2^{(1)} = \dfrac{\lambda^{(1)} - 700}{40} = \dfrac{740 - 700}{40} = 1.000000000 \\ P_{loss}^{(1)} = 0.1(P_1^{(1)})^2 = 0.004526935 \end{cases}$$

3. Calculate total generation $-P_{loss}^{(1)} + \sum_{i=1}^{n} P_i^{(1)}$

$$-P_{loss}^{(1)} + \sum_{i=1}^{2} P_i^{(1)} = -P_{loss}^{(1)} + P_1^{(1)} + P_2^{(1)} = -0.004526935 + 1.212765957 = 1.208239022$$

4. Calculate mismatch $\Delta P^{(1)} = P_D - (-P_{loss}^{(1)} + \sum_{i=1}^{n} P_i^{(1)})$

$$\Delta P^{(1)} = P_D - (-P_{loss}^{(1)} + \sum_{i=1}^{2} P_i^{(1)}) = 2 - 1.208239022 = 0.791760978$$

5. $\Delta P^{(1)} = 0.791760978 \neq 0$, calculate new system marginal cost:

$$\Delta\lambda^{(1)} = \frac{\Delta P^{(1)}}{\left(\dfrac{df(\lambda^{(1)})}{d\lambda^{(1)}}\right)^{(1)}} = \frac{0.791760978}{\dfrac{740^3 + 600 \times 740^2 + 120000 \times 740 + 170000000}{40(740 + 200)^3}} = 26.50149509$$

$$\lambda^{(2)} = \lambda^{(1)} + \Delta\lambda^{(1)} = 740 + 26.50149509 = 766.50149509$$

6. Repeat until mismatch is close to 0:

$$\begin{cases} P_1^{(2)} = \dfrac{\lambda^{(2)} - 700}{0.2\lambda^{(2)} + 40} = 0.344032034 \\ P_2^{(2)} = \dfrac{\lambda^{(2)} - 700}{40} = 1.662537377 \\ P_{loss}^{(2)} = 0.1(P_1^{(2)})^2 = 0.011835804 \end{cases}$$

$$-P_{loss}^{(2)} + \sum_{i=1}^{2} P_i^{(2)} = -P_{loss}^{(2)} + P_1^{(2)} + P_2^{(2)} = 1.994733607$$

$$\Delta P^{(2)} = P_D - (-P_{loss}^{(2)} + \sum_{i=1}^{2} P_i^{(2)}) = 0.005266393 \neq 0$$

keep iteration:

$$\Delta\lambda^{(2)} = \frac{\Delta P^{(2)}}{\left(\frac{df(\lambda^{(2)})}{d\lambda^{(2)}}\right)^{(2)}} = \frac{0.005266393}{\frac{740^3 + 600 \times 740^2 + 120000 \times 740 + 170000000}{40(740+200)^3}} = 0.178607300$$

$$\lambda^{(3)} = \lambda^{(2)} + \Delta\lambda^{(2)} = 766.50149509 + 0.178607300 = 766.6801024$$

$$\begin{cases} P_1^{(3)} = \dfrac{\lambda^{(3)} - 700}{0.2\lambda^{(3)} + 40} = 0.344892288 \\ P_2^{(3)} = \dfrac{\lambda^{(3)} - 700}{40} = 1.667002560 \\ P_{loss}^{(3)} = 0.1(P_1^{(3)})^2 = 0.011895069 \end{cases}$$

$$-P_{loss}^{(3)} + \sum_{i=1}^{2} P_i^{(3)} = -P_{loss}^{(3)} + P_1^{(3)} + P_2^{(3)} = 1.999999779$$

$$\Delta P^{(3)} = P_D - (-P_{loss}^{(3)} + \sum_{i=1}^{2} P_i^{(3)}) = 0.000000221 \approx 0$$

end of iteration.

Determine the optimal dispatch when taking transmission losses into account:

$$\begin{cases} P_1 = 0.344892288 \times 100MW = 34.4892288MW \\ P_2 = 1.667002560 \times 100MW = 166.7002560MW \\ P_{loss} = 0.011895069 \times 100MW = 1.1895069MW \end{cases}$$

$$\lambda = 766.50149509$$

$$\begin{cases} C_1 = 20P_1^2 + 700P_1 + 1000 = 48932.60 \\ C_2 = 20P_2^2 + 700P_2 + 1000 = 673469.69 \end{cases}$$

Question 2

Q2.1

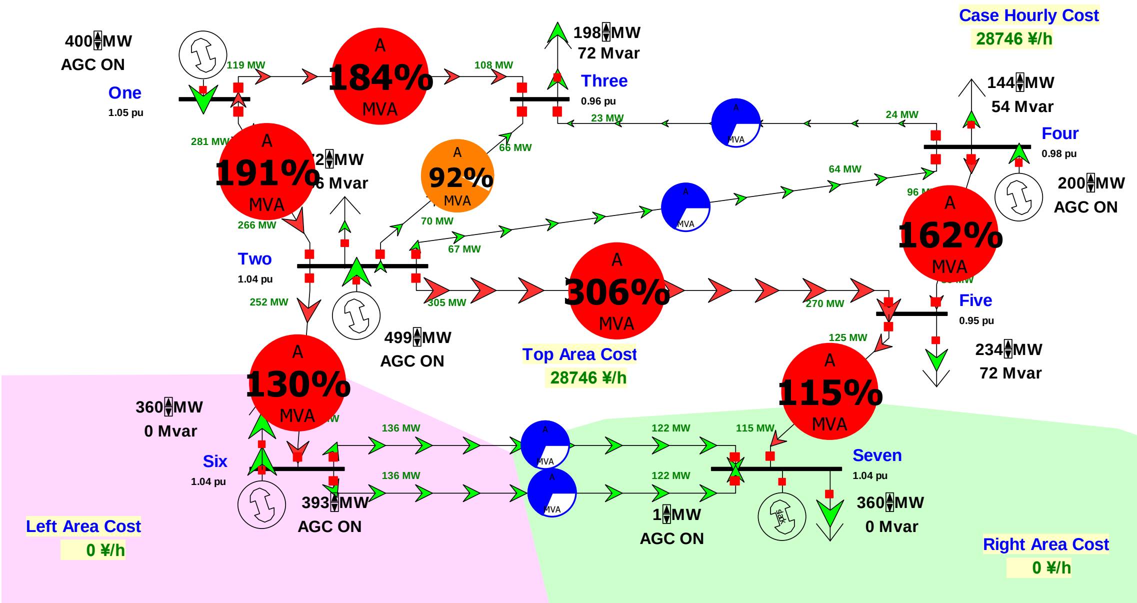

Fig 2. Power flow in ED mode when neglecting transimission losses

	From Number	From Name	To Number	To Name	Circuit	Status	Branch Device Type	Xfrmr	MW From	Mvar From	MVA From	Lim MVA	% of MVA Limit (Max)	MW Loss	Mvar Loss
1	1	One	2	Two	1	Closed	Line	NO	281.1	-54.9	286.5	150.0	191.0	14.82	37.91
2	1	One	3	Three	1	Closed	Line	NO	118.9	13.2	119.6	65.0	184.0	10.44	26.26
3	2	Two	3	Three	1	Closed	Line	NO	69.5	25.0	73.9	80.0	92.4	3.09	5.27
4	2	Two	4	Four	1	Closed	Line	NO	66.7	12.9	67.9	100.0	67.9	2.59	3.68
5	2	Two	5	Five	1	Closed	Line	NO	304.8	27.9	306.1	100.0	306.1	34.69	101.08
6	2	Two	6	Six	1	Closed	Line	NO	252.1	-65.9	260.6	200.0	130.3	12.49	32.07
7	3	Three	4	Four	1	Closed	Line	NO	-23.1	-65.3	69.3	100.0	69.3	0.51	-0.35
8	4	Four	5	Five	1	Closed	Line	NO	96.4	-9.7	96.9	60.0	161.5	7.77	18.64
9	7	Seven	5	Five	1	Closed	Line	NO	-114.8	199.4	230.1	200.0	115.0	9.95	25.87
10	6	Six	7	Seven	1	Closed	Line	NO	136.3	-24.6	138.5	200.0	69.2	14.09	36.86
11	6	Six	7	Seven	2	Closed	Line	NO	136.3	-24.6	138.5	200.0	69.2	14.09	36.86

Fig 3. Power flow in transimission lines

	Number of Bus	Name of Bus	Area Name of Load	Zone Name of Load	ID	Status	MW	Mvar	MVA	S MW	S Mvar	Dist Status	Dist MW Input	Dist Mvar Input
1	2	Two	Top	1	1	Closed	72.00	36.00	80.50	72.00	36.00	Closed	0.00	0.00
2	3	Three	Top	1	1	Closed	198.00	72.00	210.68	198.00	72.00	Closed	0.00	0.00
3	4	Four	Top	1	1	Closed	144.00	54.00	153.79	144.00	54.00	Closed	0.00	0.00
4	5	Five	Top	1	1	Closed	234.00	72.00	244.83	234.00	72.00	Closed	0.00	0.00
5	6	Six	Top	1	1	Closed	360.00	0.00	360.00	360.00	0.00	Closed	0.00	0.00
6	7	Seven	Top	1	1	Closed	360.00	0.00	360.00	360.00	0.00	Closed	0.00	0.00

Fig 4. Load profile

	Number	Name	Area Name	Nom kV	PU Volt	Volt (kV)	Angle (Deg)	Load MW	Load Mvar	Gen MW	Gen Mvar	Switched Shunts Mvar	Act G Shunt MW	Act B Shunt Mvar	Area Num	Zone Num
1	1	One	Top	138.00	1.05000	144.900	36.73			400.00	-41.65		0.00	0.00	1	1
2	2	Two	Top	138.00	1.04000	143.520	27.29	72.00	36.00	498.83	128.73		0.00	0.00	1	1
3	3	Three	Top	138.00	0.95865	132.293	21.02	198.00	72.00				0.00	0.00	1	1
4	4	Four	Top	138.00	0.98121	135.407	21.05	144.00	54.00	200.00	100.00		0.00	0.00	1	1
5	5	Five	Top	138.00	0.95163	131.325	6.34	234.00	72.00				0.00	0.00	1	1
6	6	Six	Top	138.00	1.04000	143.520	18.58	360.00	0.00	392.92	48.71		0.00	0.00	1	1
7	7	Seven	Top	138.00	1.04000	143.520	0.00	360.00	0.00	0.81	322.37		0.00	0.00	1	1

Fig 5. Voltage profile

Assignment 4

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Q2.1.1

	Number of Bus	Name of Bus	ID	Status	Gen MW	Gen Mvar	Min MW	Max MW	AGC	AVR	RegBus Num	Set Volt	Min Mvar	Max Mvar	Enforce MW Limits	Part. Factor	Cost Model
1	1	One	1	Closed	400.00	-41.65	100.00	400.00	YES	YES	1	1.05000	-200.00	200.00	YES	1.00	Cubic
2	2	Two	1	Closed	498.83	128.73	150.00	500.00	YES	YES	2	1.04000	-250.00	250.00	YES	1.00	Cubic
3	4	Four	1	Closed	200.00	100.00	50.00	200.00	YES	YES	4	1.00000	-100.00	100.00	YES	1.00	Cubic
4	6	Six	1	Closed	392.92	48.71	150.00	500.00	YES	YES	6	1.04000	-250.00	250.00	YES	1.00	Cubic
5	7	Seven	1	Closed	0.81	322.37	0.00	600.00	YES	YES	7	1.04000	-300.00	300.00	YES	1.00	Cubic

Fig 6. Generators states

Table 1.Power factors of the generators

Generator	Gen MW	Gen Mvar	Power Factor	state
Gen 1	400.00	-41.65	0.9946	P at full load
Gen 2	498.83	128.73	0.9683	P almost at full load
Gen 4	200.00	100.00	0.8944	P & Q both at full load
Gen 6	392.92	48.71	0.9924	-
Gen 7	0.81	322.37	0.0025	Q exceeds max limit
Note: $PF = \frac{P}{S} = \frac{P}{\sqrt{P^2+Q^2}}$				

Q2.1.2

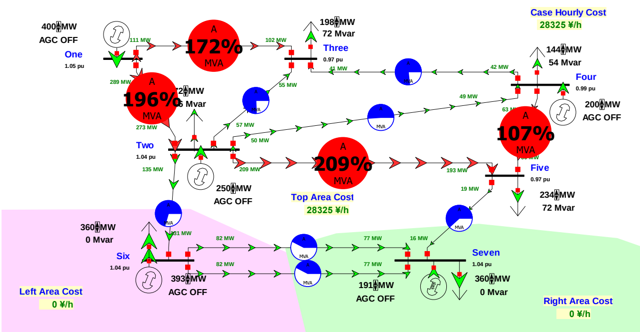
The Q generation limits of the slack busbar generator should not be restricted because slack busbar is the one to compensate Q within the network when reactive power from other busbar generators is unable to meet the network's Q requirement. If it is restricted, and other generators fail to produce the Q needed by the network, it will lead to voltage drop in busbars, if worse, voltage collapse.

From Fig 6. we can see that Q produced by Gen 4 has reached its Max Mvar. In order to compensate the Q needed by the network, Gen 7 at slack busbar produces 322.37 Mvar, which has exceeded its 300 Max Mvar, to compensate the missing Q to maintain the voltage stability in the system.

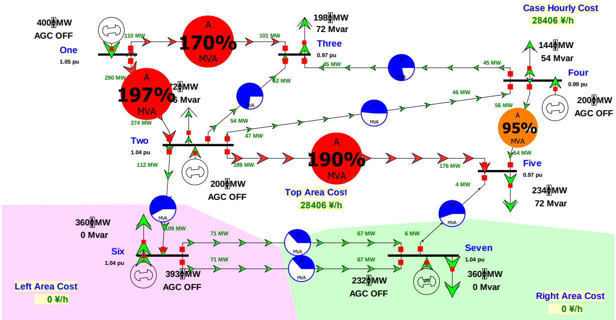
Q2.1.3

First, identify the most overloaded transmission line and the generator which is closest to the line. Then adjust the P generation of the generator. Repeat the process till all overloaded lines are around 100% loading.

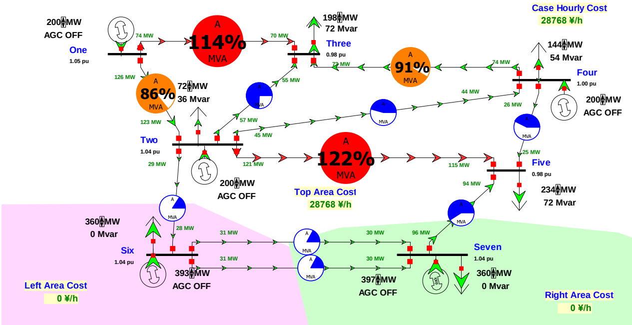
Step 1: Set Gen 2 by half to 250MW.



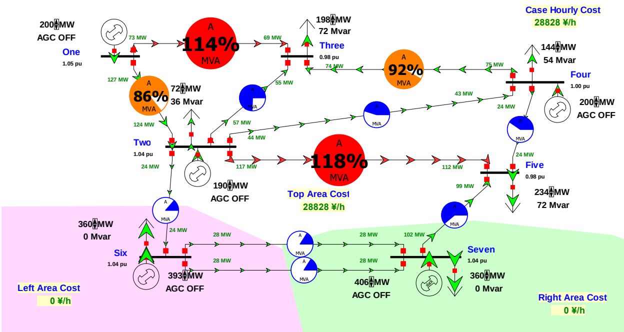
Step 2: Set Gen 2 to 200MW.



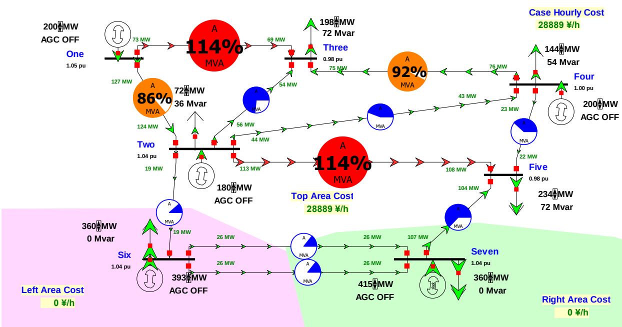
Step 3: Set Gen 1 by half to 200MW.



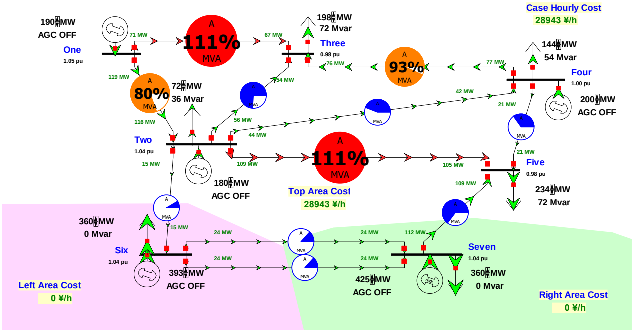
Step 4: Set Gen 2 to 190MW.



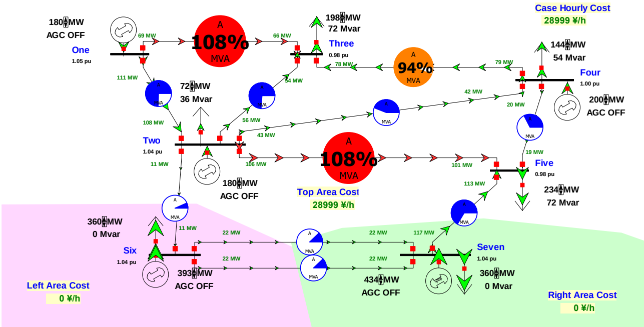
Step 5: Set Gen 2 to 180MW.



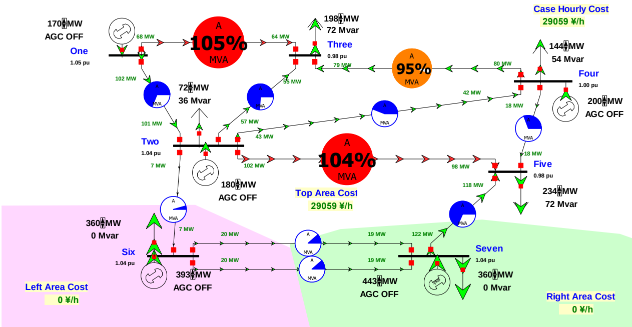
Step 6: Set Gen 1 to 190MW.



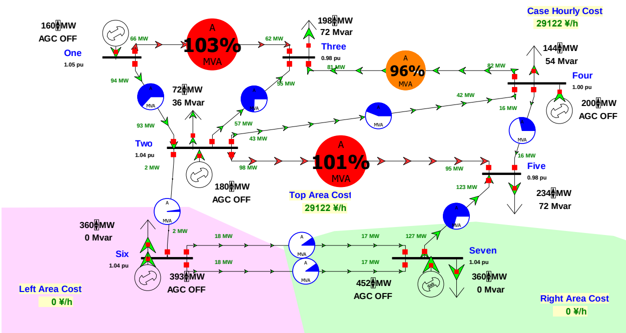
Step 7: Set Gen 1 to 180MW.



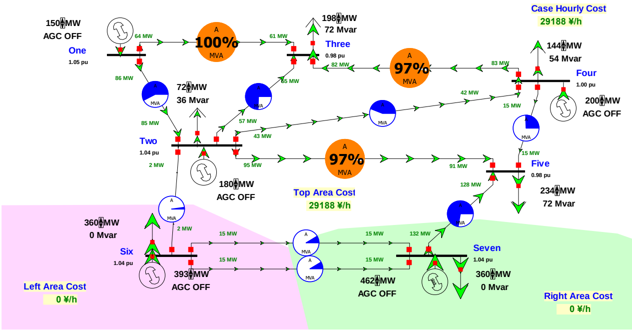
Step 8: Set Gen 1 to 170MW.



Step 9: Set Gen 1 to 160MW.



Step 10: Set Gen 1 to 150MW, P generated by Gen 1 reaches its Min MW.



	Number	Name	Area Name	Nom kV	PU Volt	Volt (kV)	Angle (Deg)	Load MW	Load Mvar	Gen MW	Gen Mvar	Switched Shunts Mvar	Act G Shunt MW	Act B Shunt Mvar	Area Num	Zone Num
1	1	One	Top	138.00	1.05002	144.903	4.90			150.00	-0.23		0.00	0.00	1	1
2	2	Two	Top	138.00	1.04001	143.521	2.10	72.00	36.00	180.00	91.81		0.00	0.00	1	1
3	3	Three	Top	138.00	0.97678	134.795	-3.02	198.00	72.00				0.00	0.00	1	1
4	4	Four	Top	138.00	1.00001	138.001	-1.85	144.00	54.00	200.00	95.26		0.00	0.00	1	1
5	5	Five	Top	138.00	0.98097	135.374	-3.76	234.00	72.00				0.00	0.00	1	1
6	6	Six	Top	138.00	1.04000	143.520	2.17	360.00	0.00	392.92	-18.44		0.00	0.00	1	1
7	7	Seven	Top	138.00	1.04000	143.520	0.00	360.00	0.00	461.66	65.16		0.00	0.00	1	1

Fig 7. Voltage profile

	From Number	From Name	To Number	To Name	Circuit	Status	Branch Device Type	Xfrmr	MW From	Mvar From	MVA From	Lim MVA	% of MVA Limit (Max)	MW Loss	Mvar Loss
1	1	One	2	Two	1	Closed	Line	NO	86.1	-12.3	87.0	150.0	58.0	1.36	-2.47
2	1	One	3	Three	1	Closed	Line	NO	63.9	12.1	65.0	65.0	100.0	3.12	4.21
3	2	Two	3	Three	1	Closed	Line	NO	56.9	17.6	59.6	80.0	74.5	2.02	1.97
4	2	Two	4	Four	1	Closed	Line	NO	43.1	7.9	43.8	100.0	43.8	1.09	-0.90
5	2	Two	5	Five	1	Closed	Line	NO	94.8	22.4	97.4	100.0	97.4	3.53	7.54
6	2	Two	6	Six	1	Closed	Line	NO	-2.0	-2.0	2.9	200.0	2.0	0.00	-5.41
7	3	Three	4	Four	1	Closed	Line	NO	-82.4	-48.5	95.6	100.0	96.8	0.95	0.89
8	4	Four	5	Five	1	Closed	Line	NO	14.7	0.8	14.7	60.0	25.7	0.18	-4.36
9	7	Seven	5	Five	1	Closed	Line	NO	132.2	59.8	145.0	200.0	72.5	3.94	7.73
10	6	Six	7	Seven	1	Closed	Line	NO	15.4	-7.5	17.2	200.0	8.6	0.19	-4.83
11	6	Six	7	Seven	2	Closed	Line	NO	15.4	-7.5	17.2	200.0	8.6	0.19	-4.83

Fig 8. Power flow in transimission lines

Filter Advanced Generator Find... Remove Quick Filter

	Number of Bus	Name of Bus	ID	Status	Gen MW	Gen Mvar	Min MW	Max MW	AGC	AVR	RegBus Num	Set Volt	Min Mvar	Max Mvar	Enforce MW Limits	Part. Factor	Cost Model
1	1	One	1	Closed	150.00	-0.23	100.00	400.00	NO	YES	1	1.05000	-200.00	200.00	YES	1.00	Cubic
2	2	Two	1	Closed	180.00	91.81	150.00	500.00	NO	YES	2	1.04000	-250.00	250.00	YES	1.00	Cubic
3	4	Four	1	Closed	200.00	95.26	50.00	200.00	NO	YES	4	1.00000	-100.00	100.00	YES	1.00	Cubic
4	6	Six	1	Closed	392.92	-18.44	150.00	500.00	NO	YES	6	1.04000	-250.00	250.00	YES	1.00	Cubic
5	7	Seven	1	Closed	461.66	65.16	0.00	600.00	NO	YES	7	1.04000	-300.00	300.00	YES	1.00	Cubic

Fig 9. Generator states

Q2.2

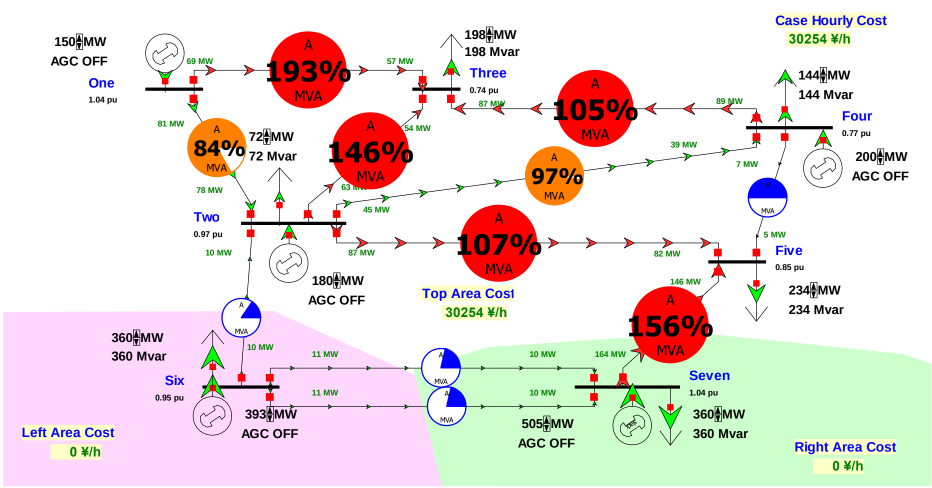


Fig 10. Power flow

	From Number	From Name	To Number	To Name	Circuit	Status	Branch Device Type	Xfrmr	MW From	Mvar From	MVA From	Lim MVA	% of MVA Limit (Max)	MW Loss	Mvar Loss
1	1	One	2	Two	1	Closed	Line	NO	81.0	95.6	125.3	150.0	83.5	3.03	3.08
2	1	One	3	Three	1	Closed	Line	NO	69.0	104.4	125.2	65.0	192.6	12.07	32.14
3	2	Two	3	Three	1	Closed	Line	NO	63.4	98.6	117.2	80.0	146.5	9.09	24.30
4	2	Two	4	Four	1	Closed	Line	NO	45.4	86.1	97.4	100.0	97.4	6.32	15.90
5	2	Two	5	Five	1	Closed	Line	NO	87.3	61.3	106.7	100.0	106.7	4.96	12.40
6	2	Two	6	Six	1	Closed	Line	NO	-10.2	24.5	26.5	200.0	15.2	0.18	-4.06
7	3	Three	4	Four	1	Closed	Line	NO	-86.7	-51.4	100.8	100.0	104.6	1.84	4.38
8	4	Four	5	Five	1	Closed	Line	NO	6.6	-29.5	30.3	60.0	50.4	1.11	0.01
9	7	Seven	5	Five	1	Closed	Line	NO	164.5	265.8	312.6	200.0	156.3	18.28	51.22
10	6	Six	7	Seven	1	Closed	Line	NO	11.3	-40.7	42.3	200.0	21.1	1.42	-0.69
11	6	Six	7	Seven	2	Closed	Line	NO	11.3	-40.7	42.3	200.0	21.1	1.42	-0.69

Fig 11. Power flow in transimission lines

	Number of Bus	Name of Bus	Area Name of Load	Zone Name of Load	ID	Status	MW	Mvar	MVA	S MW	S Mvar	Dist Status	Dist MW Input	Dist Mvar Input
1	2	Two	Top	1	1	Closed	72.00	72.00	101.82	72.00	72.00	Closed	0.00	0.00
2	3	Three	Top	1	1	Closed	198.00	198.00	280.01	198.00	198.00	Closed	0.00	0.00
3	4	Four	Top	1	1	Closed	144.00	144.00	203.65	144.00	144.00	Closed	0.00	0.00
4	5	Five	Top	1	1	Closed	234.00	234.00	330.93	234.00	234.00	Closed	0.00	0.00
5	6	Six	Top	1	1	Closed	360.00	360.00	509.12	360.00	360.00	Closed	0.00	0.00
6	7	Seven	Top	1	1	Closed	360.00	360.00	509.12	360.00	360.00	Closed	0.00	0.00

Fig 12. Load profile

	Number	Name	Area Name	Nom kV	PU Volt	Volt (kV)	Angle (Deg)	Load MW	Load Mvar	Gen MW	Gen Mvar	Switched Shunts Mvar	Act G Shunt MW	Act B Shunt Mvar	Area Num	Zone Num
1	1	One	Top	138.00	1.03739	143.160	4.29			150.00	200.00		0.00	0.00	1	1
2	2	Two	Top	138.00	0.96503	133.174	2.64	72.00	72.00	180.00	250.00		0.00	0.00	1	1
3	3	Three	Top	138.00	0.74039	102.174	-1.68	198.00	198.00			0.00	0.00	0.00	1	1
4	4	Four	Top	138.00	0.77322	106.704	0.41	144.00	144.00	200.00	100.00		0.00	0.00	1	1
5	5	Five	Top	138.00	0.85486	117.971	-2.91	234.00	234.00			0.00	0.00	0.00	1	1
6	6	Six	Top	138.00	0.95056	131.177	3.35	360.00	360.00	392.92	250.00		0.00	0.00	1	1
7	7	Seven	Top	138.00	1.04000	143.520	0.00	360.00	360.00	504.76	705.92		0.00	0.00	1	1

Fig 13. Voltage profile

	Number of Bus	Name of Bus	ID	Status	Gen MW	Gen Mvar	Min MW	Max MW	AGC	AVR	RegBus Num	Set Volt	Min Mvar	Max Mvar	Enforce MW Limits	Part. Factor	Cost Model
1	1	One	1	Closed	150.00	200.00	100.00	400.00	NO	YES	1	1.05000	-200.00	200.00	YES	1.00	Cubic
2	2	Two	1	Closed	180.00	250.00	150.00	500.00	NO	YES	2	1.04000	-250.00	250.00	YES	1.00	Cubic
3	4	Four	1	Closed	200.00	100.00	50.00	200.00	NO	YES	4	1.00000	-100.00	100.00	YES	1.00	Cubic
4	6	Six	1	Closed	392.92	250.00	150.00	500.00	NO	YES	6	1.04000	-250.00	250.00	YES	1.00	Cubic
5	7	Seven	1	Closed	504.76	705.92	0.00	600.00	NO	YES	7	1.04000	-300.00	300.00	YES	1.00	Cubic

Fig 14. Generator states

Q2.2.1

Voltage profile before change is shown in Fig 7 and after change is shown in Fig 13. Line loadings before change is shown in Fig 8 and after change is shown in Fig 11, we can make the data into graphs.

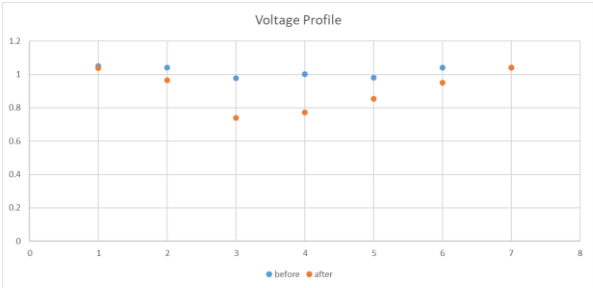


Fig 15. Voltage profile before and after change

Table 2

		1	2	3	4	5	6	7
Load MW	before		72	198	144	234	360	360
	after		72	198	144	234	360	360
Load Mvar	before		36	72	54	72	0	0
	after		72	198	144	234	360	360
Gen MW	limit	400	500		200		500	600
	before	150	180		200		392.92	461.66
	after	150	180		200		392.92	504.76
Gen Mvar	limit	200	250		100		250	300
	before	-0.23	91.81		95.26		-18.44	65.16
	after	200	250		100		250	705.92

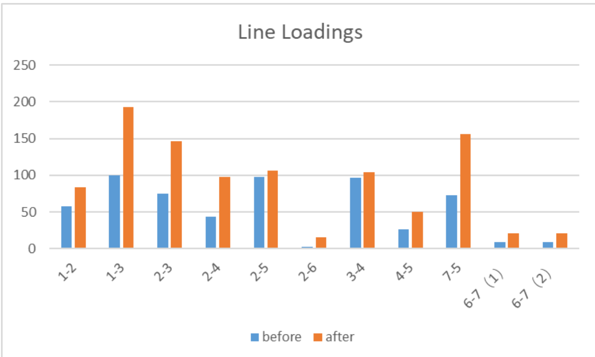


Fig 16. Line loadings before and after change

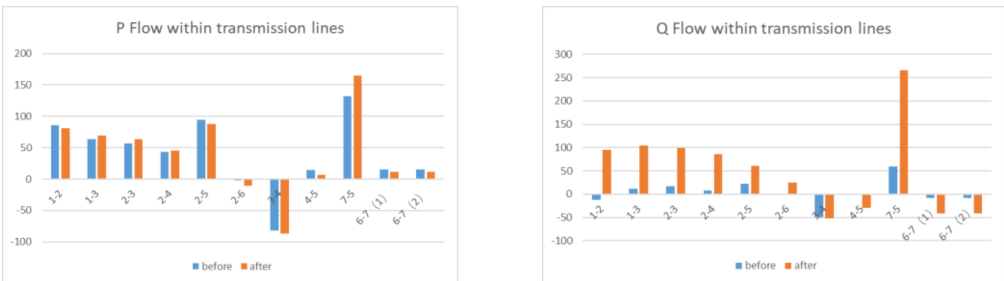


Fig 17. P & Q flow within transmission lines before and after change

When the demand for Q from loads increases, generators must increase their Q output to maintain the system's balance. However, the Q output of all generators is limited to 50% of their maximum P. According to $\Delta V = \frac{PR+QX}{V} + j\frac{PX-QR}{V}$, when R is largely smaller than L, the voltage drop is primarily caused by Q flow. This means that if the Q demand of the load is supplied by other generator busbars, there will be a voltage drop and higher line loadings. However, if the local generator can meet the local demand, there should be no voltage drop. Gen 1 has enough Q to meet the local demand, keeping the voltage at busbar 1 to 1.04pu. Gen 2 and Gen 6 have up to 250 Mvar to support the network. Apart from meeting local demand, they also contribute to other busbar, so there is a little voltage drop in busbar 2 and busbar 6. Bus 3 and Bus 5 are PQ busbar, they don't have generator to provide Q for their local demands, the Q are all from other generators at other busbars, so their voltage magnitude is quite low. As for Bus 4, although it has a generator to provide Q, but the generator can only generate 100Mvar, not enough to meet 144Mvar, so its voltage magnitude is also quite low.

Line loading is also affected by the power flow within transmission lines, since Bus 3 and Bus 5 are PQ bus, they need power from generators at other busbars, so the line loading related to these two PQ bus are quite high, such as L1-3, L2-3, L3-4, L7-5. Bus 4 can not provide enough Q for its local demand, it also needs Q from other busbar, this also results in the high loading in L2-4, L3-4.

Q2.2.2

If the voltage setting is increased, the Var output will also increase. Based on $\Delta V = \frac{PR+QX}{V} + j\frac{PX-QR}{V}$, assuming that the voltage of the other end busbar is set, an increase in the voltage of the targeted busbar results in a higher ΔV, which requires more Q to go through the line, which leads to the increase in the Var output. However, in stable system operation, the critical point of the QV curve is not considered.

Q2.2.3

Requirements: 1. keep the busbar voltage within ±5% of their nominal values

2. keep line flows below limits

3. minimize the cost of operation

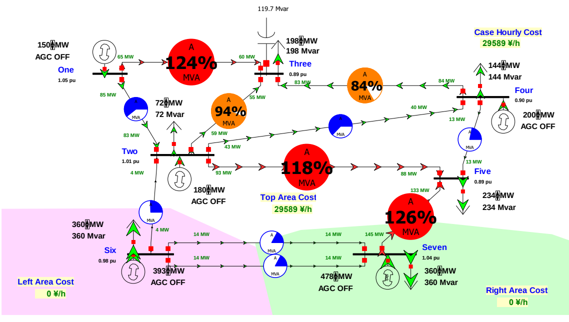
Modify: 1. identify the busbar which is a PQ bus and its voltage magnitude is the lowest.

2. add shunt capacitor at that PQ bus.

3. check whether the modification meets the requirements.

3. repeat the process.

Step 1: Add 150Mvar at busbar 3.



Assignment 4

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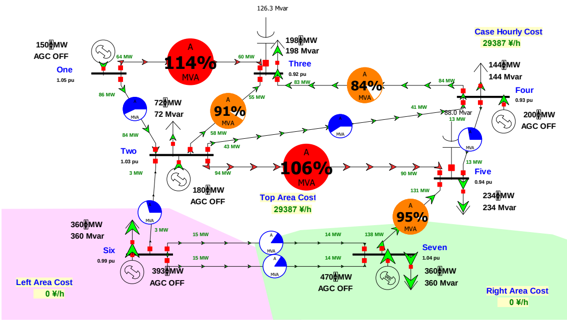
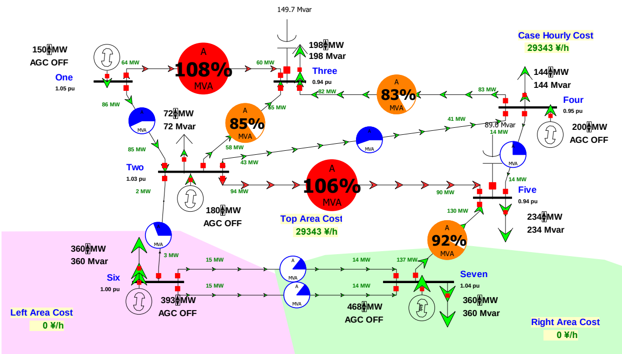
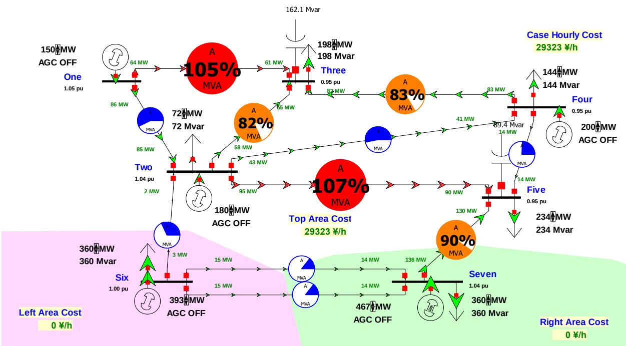
Step 2: Add 150Mvar at busbar 3, 100Mvar at busbar 5.



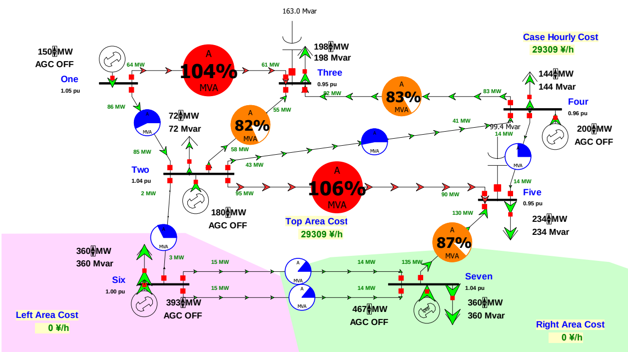
Step 3: Add 170Mvar at busbar 3, 100Mvar at busbar 5.



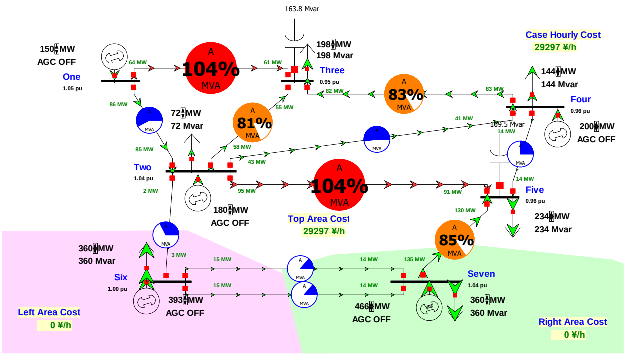
Step 4: Add 180Mvar at busbar 3, 100Mvar at busbar 5.



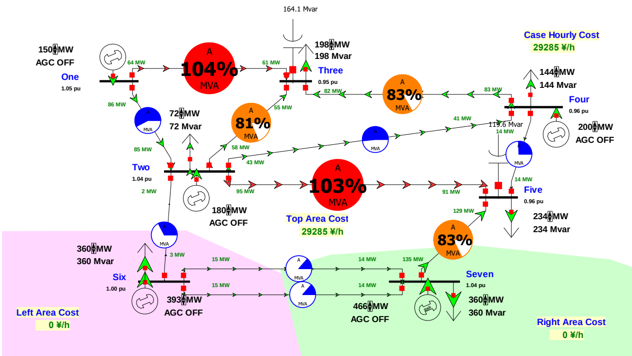
Step 5: Add 180Mvar at busbar 3, 110Mvar at busbar 5.



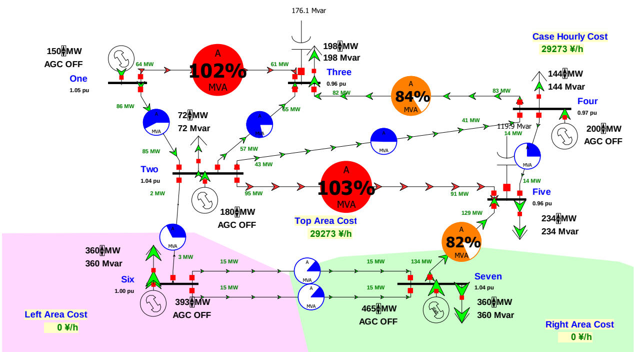
Step 6: Add 180Mvar at busbar 3, 120Mvar at busbar 5.



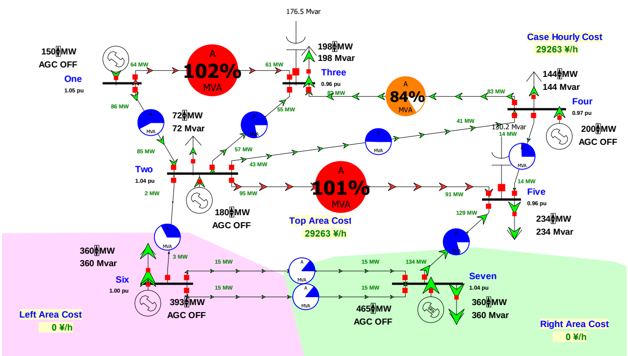
Step 7: Add 180Mvar at busbar 3, 130Mvar at busbar 5.



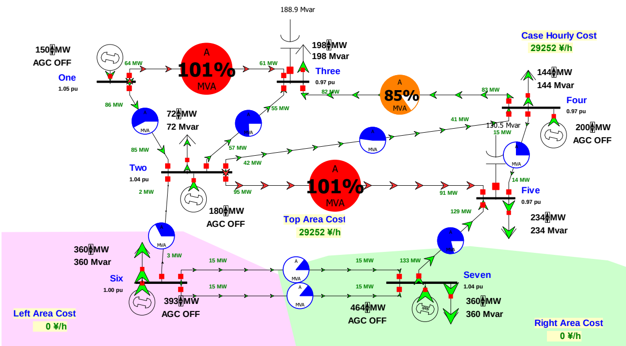
Step 8: Add 190Mvar at busbar 3, 130Mvar at busbar 5.



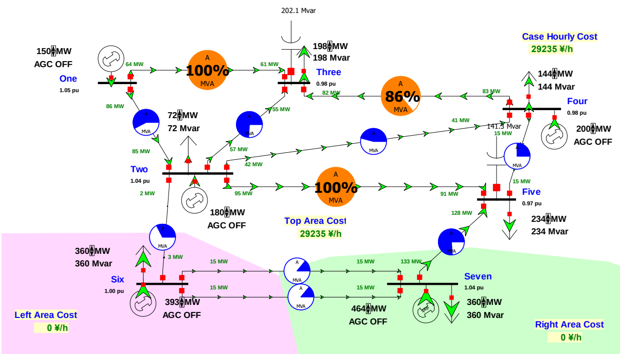
Step 9: Add 190Mvar at busbar 3, 140Mvar at busbar 5.



Step 10: Add 200Mvar at busbar 3, 140Mvar at busbar 5.



Step 11: Add 210Mvar at busbar 3, 140Mvar at busbar 5.



Filter Advanced Generator Find... Remove Quick Filter

	Number of Bus	Name of Bus	ID	Status	Gen MW	Gen Mvar	Min MW	Max MW	AGC	AVR	RegBus Num	Set Volt	Min Mvar	Max Mvar	Enforce MW Limits	Part. Factor	Cost Model
1	1	One	1	Closed	150.00	-2.05	100.00	400.00	NO	YES	1	1.05000	-200.00	200.00	YES	1.00	Cubic
2	2	Two	1	Closed	180.00	208.30	150.00	500.00	NO	YES	2	1.04000	-250.00	250.00	YES	1.00	Cubic
3	4	Four	1	Closed	200.00	100.00	50.00	200.00	NO	YES	4	1.00000	-100.00	100.00	YES	1.00	Cubic
4	6	Six	1	Closed	392.92	250.00	150.00	500.00	NO	YES	6	1.04000	-250.00	250.00	YES	1.00	Cubic
5	7	Seven	1	Closed	463.60	474.51	0.00	600.00	NO	YES	7	1.04000	-300.00	300.00	YES	1.00	Cubic

Fig 18. Generator states.

Filter Advanced Branch Find... Remove Quick Filter

	From Number	From Name	To Number	To Name	Circuit	Status	Branch Device Type	Xfrmr	MW From	Mvar From	MVA From	Lim MVA	% of MVA Limit (Max)	MW Loss	Mvar Loss
1	1	One	2	Two	1	Closed	Line	NO	85.9	-12.3	86.8	150.0	57.8	1.35	-2.49
2	1	One	3	Three	1	Closed	Line	NO	64.1	10.2	64.9	65.0	99.9	3.10	4.15
3	2	Two	3	Three	1	Closed	Line	NO	57.2	15.2	59.2	80.0	74.0	1.98	1.86
4	2	Two	4	Four	1	Closed	Line	NO	42.5	18.1	46.2	100.0	46.2	1.23	-0.41
5	2	Two	5	Five	1	Closed	Line	NO	94.8	31.0	99.7	100.0	99.7	3.72	8.11
6	2	Two	6	Six	1	Closed	Line	NO	-1.9	62.2	62.2	200.0	32.6	0.78	-2.88
7	3	Three	4	Four	1	Closed	Line	NO	-81.7	23.5	85.1	100.0	85.7	0.76	0.34
8	4	Four	5	Five	1	Closed	Line	NO	14.7	-2.3	14.9	60.0	24.8	0.18	-4.23
9	7	Seven	5	Five	1	Closed	Line	NO	132.8	77.0	153.6	200.0	76.8	4.42	9.22
10	6	Six	7	Seven	1	Closed	Line	NO	15.1	-22.5	27.1	200.0	13.5	0.50	-3.72
11	6	Six	7	Seven	2	Closed	Line	NO	15.1	-22.5	27.1	200.0	13.5	0.50	-3.72

Fig 19. Power flow in transimission lines.

Filter Advanced Bus Find... Remove Quick Filter

	Number	Name	Area Name	Nom kV	PU Volt	Volt (kV)	Angle (Deg)	Load MW	Load Mvar	Gen MW	Gen Mvar	Switched Shunts Mvar	Act G Shunt MW	Act B Shunt Mvar	Area Num	Zone Num
1	1	One	Top	138.00	1.05000	144.900	4.89			150.00	-2.05		0.00	0.00	1	1
2	2	Two	Top	138.00	1.04000	143.520	2.09	72.00	72.00	180.00	208.30		0.00	0.00	1	1
3	3	Three	Top	138.00	0.98106	135.386	-3.11	198.00	198.00			202.12	0.00	0.00	1	1
4	4	Four	Top	138.00	0.98230	135.557	-1.51	144.00	144.00	200.00	100.00		0.00	0.00	1	1
5	5	Five	Top	138.00	0.97071	133.958	-3.63	234.00	234.00			141.34	0.00	0.00	1	1
6	6	Six	Top	138.00	1.00302	138.417	2.87	360.00	360.00	392.92	250.00		0.00	0.00	1	1
7	7	Seven	Top	138.00	1.04000	143.520	0.00	360.00	360.00	463.60	474.51		0.00	0.00	1	1

Fig 20. Voltage profile.

Description: the reason for this modification is because the AVR function of the generators are all on as shown in Fig 18. So we only need to focus on PQ busbars which are busbar 3 and 5. By starting adding shunts at the busbar which has the lowest voltage magnitude, we can minimize the shunts needed and the cost of operation. From the results, 210Mvar at busbar 3 and 140Mvar at busbar 5 are needed. The cost of installation is $(210 + 140) \div 10 \times 10{,}000 = 350{,}000$£.

Question 3

Q3.1

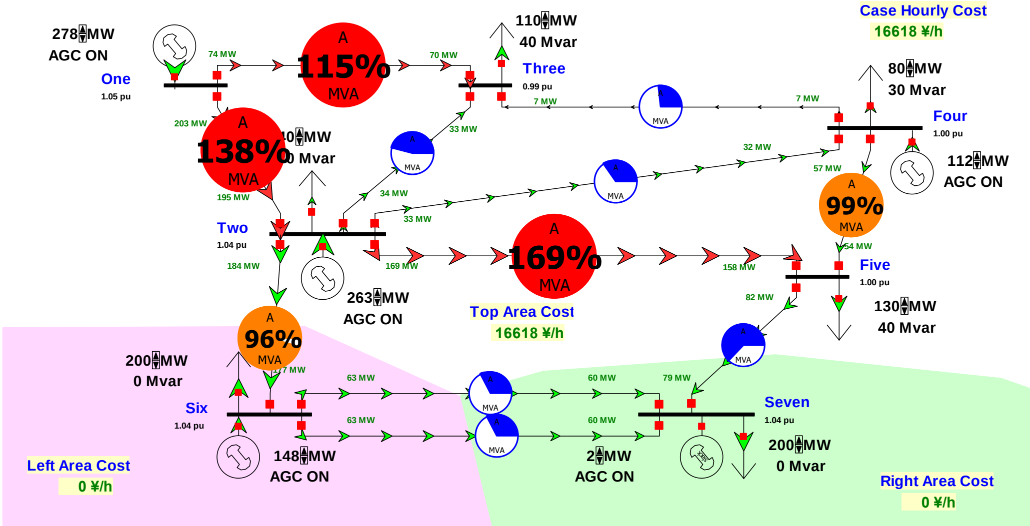


Fig 21. Simulation in ED mode while neglecting transmission loss penalty factors.

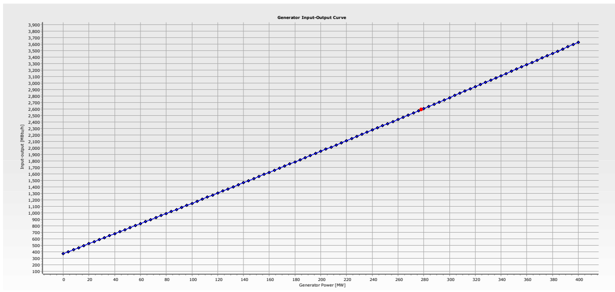


Fig 22. Gen 1 IO Curve

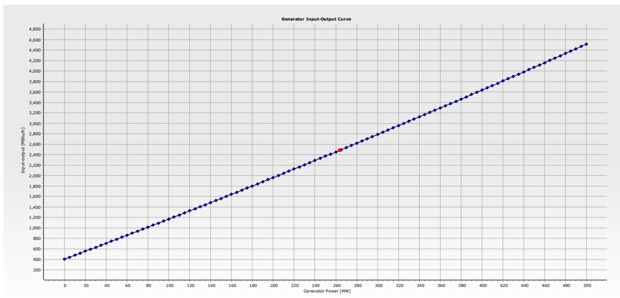


Fig 23. Gen 2 IO Curve

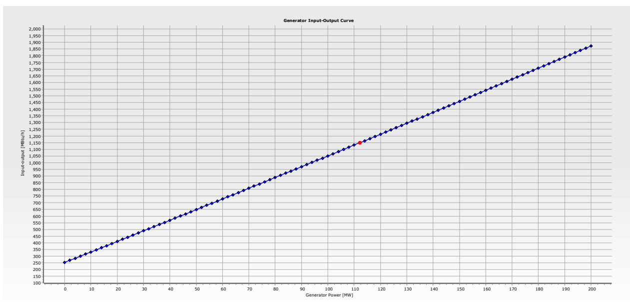


Fig 24. Gen 4 IO Curve

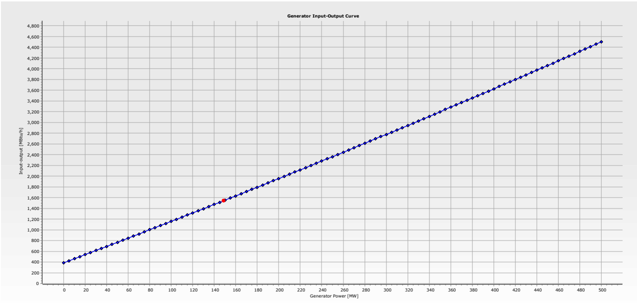


Fig 25. Gen 6 IO Curve

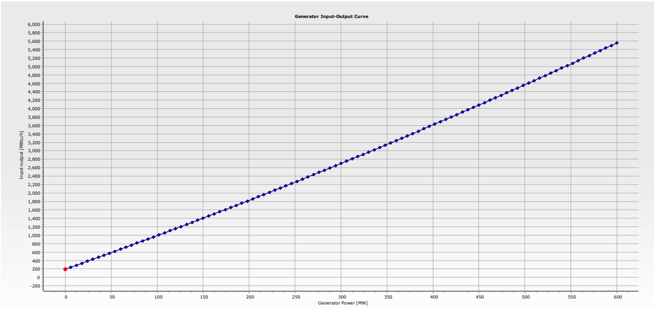


Fig 26. Gen 7 IO Curve

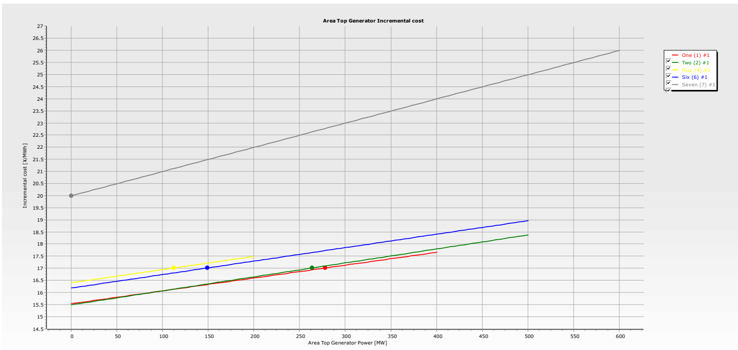


Fig 27. All area Gen IC curves

Q3.1.1

Table 3

Gen	a (fixed cost)	b	c	d	fuel cost	α	β	γ
1	761.94	7.62	0.00130	0	2.040	761.94	15.5448	0.002652
2	831.84	7.52	0.00140	0	2.061	831.84	15.49872	0.002803
4	530.03	7.84	0.00130	0	2.093	530.03	16.40912	0.002805
6	831.92	7.57	0.00130	0	2.139	831.92	16.19223	0.002802
7	500.08	7.77	0.00194	0	2.574	500.08	19.99998	0.004994

Note: 1. For cubic cost models of the form C(Pgi) = (d*Pgi^3 + c*Pgi^2 + b*Pgi) * (fuel cost) + fixed costs.

∵ d=0

∴ C(Pgi) = (c*Pgi^2 + b*Pgi) * (fuel cost) + fixed costs = α + β*Pgi + γ*Pgi^2

(α = A, β = b*fuel cost, γ = c*fuel cost)

Assignment 4

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Q3.1.2

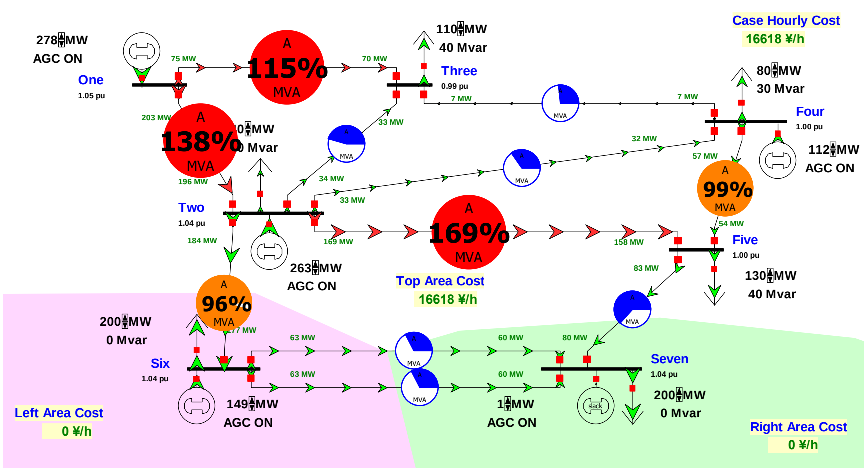

Fig 28. Solved network without including loss penalty factors

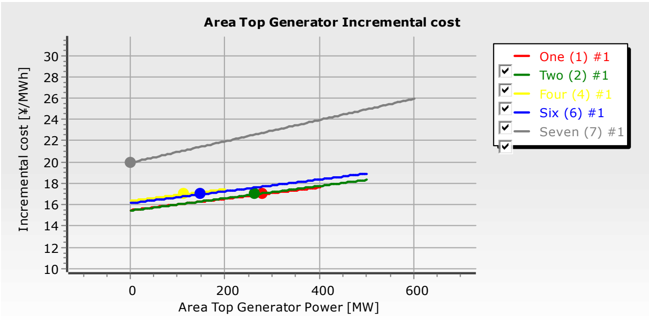

Fig 29. All area Gen IC curves

	Number of Bus	Name of Bus	Area Name of Gen	ID	Status	AGC	Gen MW	Fixed Cost(¥/hr)	Fixed Cost(Mbtu/hr)	IOB	IOC	IOD	Fuel Cost	Variable O&M	Fuel Type	Unit Type	Cost Shift ¥/MWh	Cost Multiplier	Convex?	Min MW	Max MW	Cost ¥/Hr (generation only)	IC	Loss MW Sens	Gen MW Marg. Cost
1	1	One	Top	1	Closed	YES	278.11	0.00	373.50	7.620	0.0013	0.00000	2.040	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	400.00	5290.27	17.02	0.2295	22.09
2	2	Two	Top	1	Closed	YES	263.60	0.00	403.61	7.520	0.0014	0.00000	2.061	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	500.00	5117.81	17.02	0.1653	20.39
3	4	Four	Top	1	Closed	YES	112.24	0.00	253.24	7.840	0.0013	0.00000	2.093	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	200.00	2406.07	17.02	0.1372	19.73
4	6	Six	Top	1	Closed	YES	148.83	0.00	388.93	7.570	0.0013	0.00000	2.139	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	500.00	3303.33	17.02	0.0994	18.90
5	7	Seven	Top	1	Closed	YES	0.05	0.00	194.28	7.771	0.0019	0.00000	2.574	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	600.00	501.11	20.00	0.0000	20.00

Fig 30. Generation costs

Tabe 4

Gen	a (fixed cost)	b	c	d	fuel cost	P(MW)	Simulated IC (£/MWh)	Calculated IC (£/MWh)
1	761.94	7.62	0.00130	0	2.040	277.546	17.02	17.02
2	831.84	7.52	0.00140	0	2.061	263.080	17.02	17.02
4	530.03	7.84	0.00130	0	2.093	111.688	17.02	17.02
6	831.92	7.57	0.00130	0	2.139	148.285	17.02	17.02
7	500.08	7.77	0.00194	0	2.574	1.886	20.00	20.02
Note: Incremental cost can be expressed as dC(Pgi)/dPgi.								

When neglecting loss penalty factors:

$$\frac{\partial L}{\partial P_i} = \frac{dC_i(P_i)}{dP_i} - \lambda = 0 \text{ for } P_i(\min) < P_i < P_i(\max),$$

$$\lambda = \frac{dC_i(P_i)}{dP_i} = \beta + 2\gamma P_i$$

From the simulated IC and the Calculated IC, we can see that apart from the slack busbar 7, all IC at other busbar are the same because it is running under ED mode without including loss penalty factors.

The IC at slack busbar 7 is higher is because slack bus needs to provide missing power for the whole network.

Q3.1.3

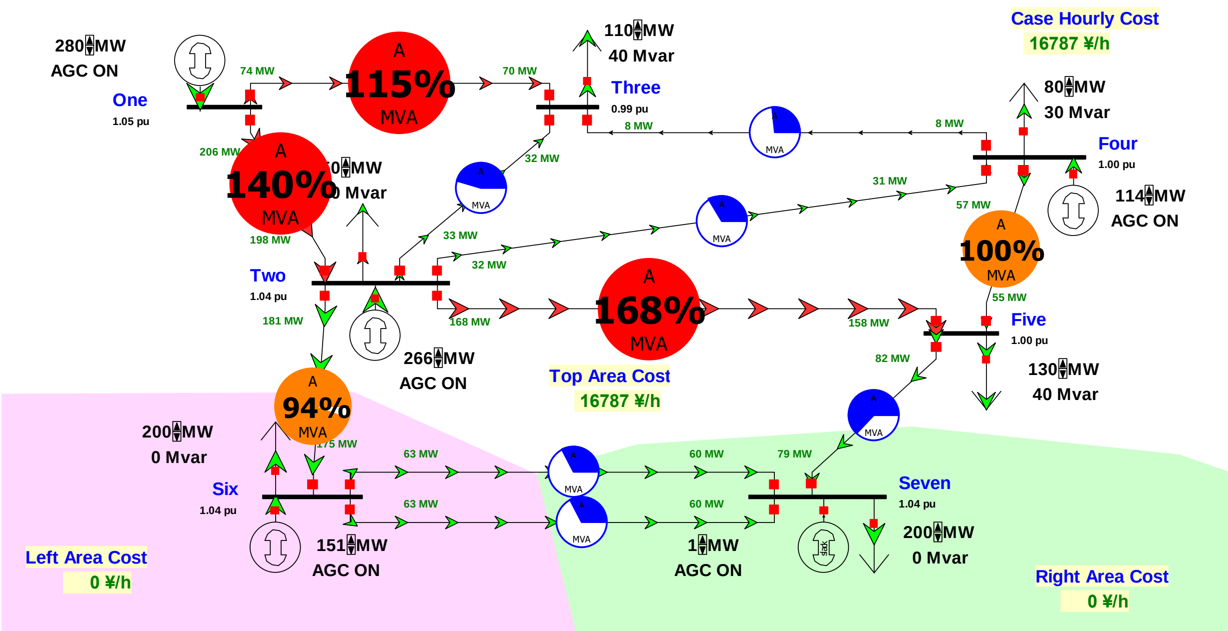

Fig 31. increase demand at Busbar 2 by 10MW

It is possible to predict the total cost of ED it the demand increases by 10MW because the system is running without including penalty factors.

If increasing the demand at Busbar 2 by 10MW, the IC at busbar 2 is 17, the total cost of ED will increase 17*10=170. From Fig 31 and Fig 28, 16787-16618=169.

Q3.1.4

Buses | Just Generators | Areas | Super Areas

	Number	Name	Area Num	Area Name	Loss MW Sens	Penalty Factor	Loss Mvar Sens
1	1	One	1	Top	0.2291	1.2972	0.0000
2	2	Two	1	Top	0.1649	1.1975	0.0000
3	3	Three	1	Top	0.1348	1.1558	-0.0065
4	4	Four	1	Top	0.1368	1.1585	0.0000
5	5	Five	1	Top	0.0369	1.0383	-0.0186
6	6	Six	1	Top	0.0991	1.1100	0.0000
7	7	Seven	1	Top	0.0000	1.0000	0.0000

Fig 32. Loss Sensitivities

Prediction: Based on the consideration of transmission losses, it is expected that Gen 1 and Gen 2 will reduce their output, because generators with a high penalty factor will experience more loss, leading to a reduction in output. Gen 4 and Gen 6 will increase their output, because generators with a low penalty factor will experience less loss and therefore increase their output.

Assignment 4

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Q3.2

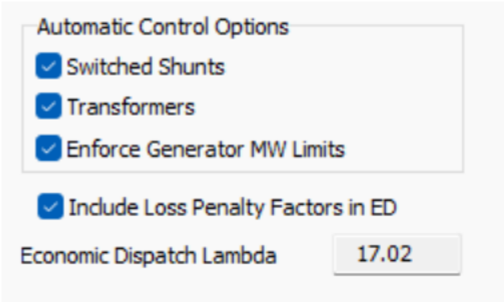

Fig 33. Operated in ED mode with transmission losses included.

Q3.2.1

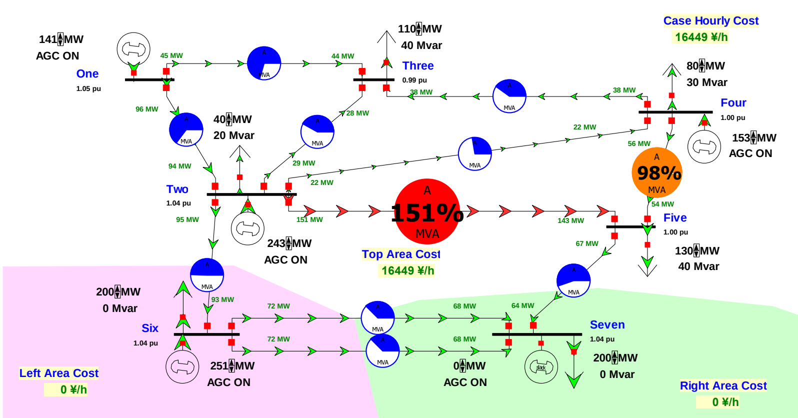

Fig 34. Solved network with transmission losses included.

Filter | Advanced | Generator | Find... | Remove | Quick Filter

	Number of Bus	Name of Bus	ID	Status	Gen MW	Gen Mvar	Min MW	Max MW	AGC	AVR	RegBus Num	Set Volt	Min Mvar	Max Mvar	Enforce MW Limits	Part. Factor	Cost Model
1	1	One	1	Closed	277.55	-36.73	0.00	400.00	YES	YES	1	1.05000	-9900.00	9900.00	YES	1.00	Cubic
2	2	Two	1	Closed	263.08	44.97	0.00	500.00	YES	YES	2	1.04000	-9900.00	9900.00	YES	1.00	Cubic
3	4	Four	1	Closed	111.69	24.89	0.00	200.00	YES	YES	4	1.00000	-9900.00	9900.00	YES	1.00	Cubic
4	6	Six	1	Closed	148.29	30.57	0.00	500.00	YES	YES	6	1.04000	-9900.00	9900.00	YES	1.00	Cubic
5	7	Seven	1	Closed	1.89	143.22	0.00	600.00	YES	YES	7	1.04000	-99999.00	99999.00	YES	1.00	Cubic

Fig 35. Generators output without penalty factors

Filter | Advanced | Generator | Find... | Remove | Quick Filter

	Number of Bus	Name of Bus	ID	Status	Gen MW	Gen Mvar	Min MW	Max MW	AGC	AVR	RegBus Num	Set Volt	Min Mvar	Max Mvar	Enforce MW Limits	Part. Factor	Cost Model
1	1	One	1	Closed	141.06	-5.84	0.00	400.00	YES	YES	1	1.05000	-9900.00	9900.00	YES	1.00	Cubic
2	2	Two	1	Closed	243.42	27.40	0.00	500.00	YES	YES	2	1.04000	-9900.00	9900.00	YES	1.00	Cubic
3	4	Four	1	Closed	152.77	6.90	0.00	200.00	YES	YES	4	1.00000	-9900.00	9900.00	YES	1.00	Cubic
4	6	Six	1	Closed	250.69	-8.47	0.00	500.00	YES	YES	6	1.04000	-9900.00	9900.00	YES	1.00	Cubic
5	7	Seven	1	Closed	-0.02	143.25	0.00	600.00	YES	YES	7	1.04000	-99999.00	99999.00	YES	1.00	Cubic

Fig 36. Generators output with penalty factors

From Fig 35 and 36, we can see that Gen 1 reduced the P output from 277.55MW to 141.06MW, Gen 2 reduced the P output from 263.08MW to 243.42MW. Gen 4 increased the P output from 111.69MW to 152.77MW, Gen 6 increased the P output from 148.29MW to 250.69MW. The overall cost of dispatch decreased from 16618 to 16449. The results match the prediction.

Q3.2.2

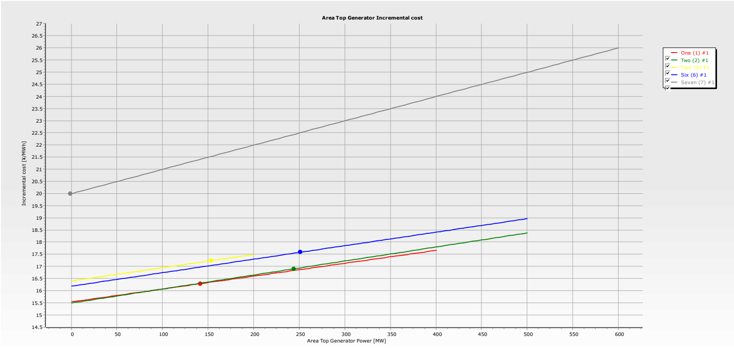

Fig 37. All area Gen IC curves

How and why has the overall generation cost changed?

Taking penalty factor into consideration, generators with higher penalty factors have lower IC, while those with lower penalty factors have higher IC, as indicated by $\lambda = \frac{1}{1-\frac{\partial P_{loss}}{\partial P_i}}\frac{dC_i(P_i)}{dP_i}$. As a result, generators with higher penalty factors produce less, and those with lower penalty factors produce more, in order to minimize transmission losses. This leads to a reduction in the overall generation cost.

Calculate the savings:

16618 – 16449 = 169

Discuss both dispatch costs and losses:

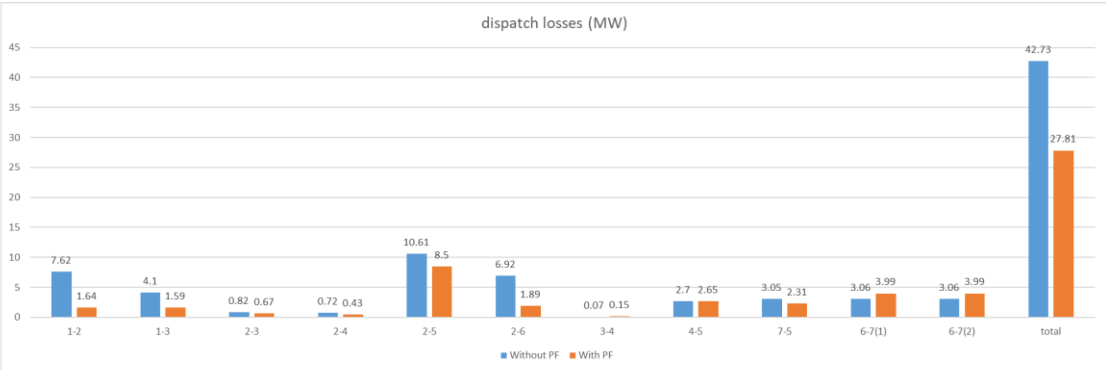

Fig 38. dispatch losses

The dispatch losses is reduced when penalty factors are introduced into the system.

Check the calues of IC, penalty factors and Lambdas for each generators:

	Number	Name	Area Num	Area Name	Loss MW Sens	Penalty Factor	Loss Mvar Sens
1	1	One	1	Top	0.1770	1.2151	0.0000
2	2	Two	1	Top	0.1462	1.1712	0.0000
3	3	Three	1	Top	0.1211	1.1378	-0.0055
4	4	Four	1	Top	0.1291	1.1483	0.0000
5	5	Five	1	Top	0.0306	1.0315	-0.0166
6	6	Six	1	Top	0.1117	1.1257	0.0000
7	7	Seven	1	Top	0.0000	1.0000	0.0000

Fig 39. Penalty factors

	Number of Bus	Name of Bus	Area Name of Gen	ID	Status	AGC	Gen MW	Fixed Cost(¥/hr)	Fixed Cost(Mbtu/hr)	IOB	IOC	IOD	Fuel Cost	Variable O&M	Fuel Type	Unit Type	Cost Shift ¥/MWh	Cost Multiplier	Convex?	Min MW	Max MW	Cost ¥/Hr (generation only)	IC	Loss MW Sens	Gen MW Marg. Cost
1	1	One	Top	1	Closed	YES	140.71	0.00	373.50	7.620	0.0013	0.00000	2.040	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	400.00	3001.74	16.29	0.1770	19.79
2	2	Two	Top	1	Closed	YES	243.05	0.00	403.61	7.520	0.0014	0.00000	2.061	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	500.00	4769.21	16.90	0.1462	19.79
3	4	Four	Top	1	Closed	YES	152.37	0.00	253.24	7.840	0.0013	0.00000	2.093	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	200.00	3093.52	17.24	0.1291	19.79
4	6	Six	Top	1	Closed	YES	250.28	0.00	388.93	7.570	0.0013	0.00000	2.139	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	500.00	5058.65	17.58	0.1117	19.79
5	7	Seven	Top	1	Closed	YES	1.31	0.00	194.28	7.771	0.0019	0.00000	2.574	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	600.00	526.38	20.02	0.0000	20.02

Fig 40. IC values and Lambdas for each generators in ED

From Fig 40 we can see that the equal lambda criterion still hold.

Q3.3

Q3.3.1

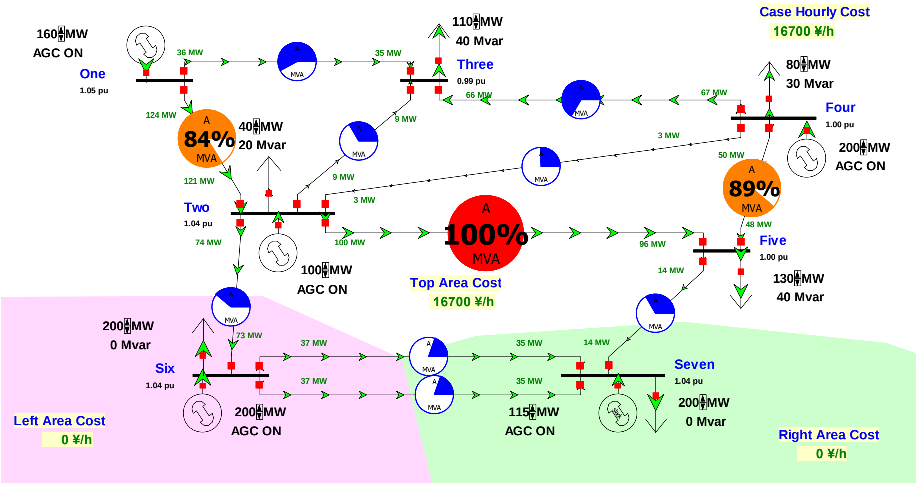

Fig 41. Solved network with full OPF

	Number of Bus	Name of Bus	Area Name of Gen	ID	Status	AGC	Gen MW	Fixed Cost(¥/hr)	Fixed Cost(Mbtu/hr)	IOB	IOC	IOD	Fuel Cost	Variable O&M	Fuel Type	Unit Type	Cost Shift ¥/MWh	Cost Multiplier	Convex?	Min MW	Max MW	Cost ¥/Hr (generation only)	IC	Loss MW Sens	Gen MW Marg. Cost
1	1	One	Top	1	Closed	YES	160.00	0.00	373.50	7.620	0.0013	0.00000	2.040	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	400.00	3317.00	16.39	0.1770	16.39
2	2	Two	Top	1	Closed	YES	99.62	0.00	403.61	7.520	0.0014	0.00000	2.061	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	500.00	2404.41	16.07	0.1462	16.07
3	4	Four	Top	1	Closed	YES	200.00	0.00	253.24	7.840	0.0013	0.00000	2.093	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	200.00	3920.69	17.50	0.1291	17.50
4	6	Six	Top	1	Closed	YES	200.00	0.00	388.93	7.570	0.0013	0.00000	2.139	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	500.00	4181.60	17.30	0.1117	17.30
5	7	Seven	Top	1	Closed	YES	115.47	0.00	194.28	7.771	0.0019	0.00000	2.574	0.000	UN (Unk	UN (Unk	0.000	1.000	YES	0.00	600.00	2876.50	21.16	0.0000	21.16

Fig 42. IC values and Lambdas for each generators in OPF

The result of ED is shown in Fig 34, and the result of OPF is shown in Fig 41. The cost of ED is 16447 and the cost of OPF is 16700.

The line loading at L2-5 is relaxed from 151% in ED to 100% in OPF. The reason for that is because in OPF, the output from Gen 1, Gen 4 and Gen 7 has increased, while the output in Gen 2 and in Gen 6 has decreased, as shown in Fig 40 and Fig 42. Due to the higher output of Gen 4 to meet local demand, less power is transmitted through L2-5, causing a reduction in the output of Gen 2. So Gen 1 must increase its output to meet the local demand. However, taking into account the penalty factor of each generator, this increase in output results in a higher generation cost.

Q3.3.2

Lines/Transformers | Interfaces | Nomogram Interfaces

	From Number	From Name	From Area Name	To Number	To Name	To Area Name	Circuit	Monitor	Max MVA	% of MVA Limit (Max)	Lim MVA	MVA Marg. Cost	Constraint Status
1	1	One	Top	2	Two	Top	1	YES	125.7	83.8	150.0		
2	1	One	Top	3	Three	Top	1	YES	38.0	58.5	65.0		
3	2	Two	Top	3	Three	Top	1	YES	26.5	33.1	80.0		
4	2	Two	Top	4	Four	Top	1	YES	25.3	25.3	100.0		
5	2	Two	Top	5	Five	Top	1	YES	100.0	100.0	100.0	12.1	Binding
6	2	Two	Top	6	Six	Top	1	YES	78.5	39.3	200.0		
7	3	Three	Top	4	Four	Top	1	YES	66.7	66.7	100.0		
8	4	Four	Top	5	Five	Top	1	YES	53.3	88.8	60.0		
9	7	Seven	Top	5	Five	Top	1	YES	67.3	33.6	200.0		
10	6	Six	Top	7	Seven	Top	1	YES	38.8	19.4	200.0		
11	6	Six	Top	7	Seven	Top	2	YES	38.8	19.4	200.0		

Fig 43. Lagrange multipliers of the system

If a given Lagrange multiplier is zero, the corresponding constraint is not active or applied.

A non-zero Lagrange multiplier gives the “shadow marginal cost”of a given constraint, i.e. the reduction in the total cost if a given constraint is marginally relaxed.

For example, if there is a constraint on the transmission line flow, the corresponding Lagrange multiplier shows by how much the generation cost would be reduced if the constraint was relaxed (i.e. the line flow limit increased) by 1MW.

From Fig 42, the MVA Marg. Cost is simulated as 12.1 at L2-5. This means that the constraint is L2-5 limit, and when L2-5 is relaxed by 1MW, the cost will decreased by 12.1.

Question 4

A.4 The need for, and operation of, the electricity balancing market.

The electricity balancing market plays an important role in the electricity industry in the UK. It is responsible for maintaining the balance between power supply and demand in real-time. The need for this market is because the inherent uncertainty between power generation and demand. Power generation from renewable sources such as wind and solar are not very reliable because wind energy and solar energy are not completely predictable. And the demand for electricity has its own pattern throughout the day. So the electricity balancing market is needed to help ensuring that there is enough supply for demand.

There are several players in the electricity market in the UK, such as the retailers. From their perspective, they can benefit from the electricity balancing market by buying and selling energy. They buy at the wholesale market and sell to the customers, acting as the middle role. So the consumers won’t needed to be connected to the same part of the distribution network. The electricity balancing market provides a platform for retailers to offer these kinds of services to the customers. As a result, it helps to reduce peak demand on the grid.

As for other players, such as the electricity system operator (ESO) and distribution company (Disco), the electricity balancing market is essential since it helps them to manage the grid's stability and reliability. The responsibility of the ESO is to ensure that the electricity system is balanced. It also make sure that there is enough electricity supply to meet demand. The market enables ESO to get additional electricity supply. It helps to reduce demand in real-time to maintain grid stability as well.

Consumers also benefit from the electricity balancing market. It ensures that there is a constant supply of electricity, which helps to prevent power outages. The market also helps to keep the electricity prices stable and avoids price spikes during peak demand.

The operation of the electricity balancing market in the UK involves a complex set of operations. ESO manages the market and obtains additional electricity supply or reduces demand to maintain grid stability. The market operates nonstop and has several reserve services, including the Balancing Mechanism start-up and the Short Term Operating Reserve.

The Balancing Mechanism is primary for balancing electricity supply and demand. It is a flexible market that allows generators and consumers to adjust their electricity supply or demand in response to changes in the grid's balance. The Short Term Operating Reserve market is another market that ESO uses to procure additional electricity supply or reduce demand in real-time. It is a more rigid market that is used when there is a sudden shortage of electricity supply.

A.5 A comparison of different incentive schemes to reward renewable energy generation

The earliest scheme to reward renewable energy generation is called the Non-Fossil Fuel Obligation (NFFO), which was introduced in 1990. Followed by the Climate Change Levy (CCL) which was proposed in 2001. In 2002, the Renewable Obligation (RO) was put forward. Later in 2010, the Feed-in Tariff (FiT) was introduced. The Electricity Market Reform (EMR) was brought up in 2013. Form all these schemes, we can notice that the UK government has done a lot to promote renewable energy development and to reduce carbon emissions through out the years.

The NFFO scheme was designed to support the development of renewable energy projects. It asked electricity suppliers to buy a specific amount of electricity from renewable sources. But this needs the suppliers to go through a bidding process.

Later in 2002, the RO scheme replaced the NFFO scheme. This new scheme gave out licenses to electricity suppliers, so the suppliers can promote their electricity from renewable sources. This scheme has different levels of support for different technologies. It includes several mechanisms such as Contracts for Difference (CfD), Capacity Market, Carbon Price Floor, and Emission Performance Standards (EPS). The CfD was the primary mechanism. This new scheme also promoted large-scale renewable energy projects.

The EMR scheme is a set of reforms which motive investment in low-carbon electricity generation. It also ensures a secure supply in electricity.

After comparing, it can be noticed that the NFFO scheme and the RO scheme shared a common objective. They all require the electricity suppliers to get a certain amount of electricity which is generated from renewable sources. However, the NFFO uses a competitive bidding process to award contracts. On the other hand, the RO provides a fixed level of support for different technologies. The CCL scheme is a tax on energy use. It encourages businesses and organizations to decrease their energy consumption and carbon emissions. The revenue from the tax was then used to support energy efficiency and low-carbon initiatives. It differs from the NFFO and the RO, which used incentives for renewable energy development.

The FiT scheme provides some financial incentives for small-scale renewable energy projects, such as solar photovoltaics, wind, micro-hydro, anaerobic digestion and domestic scale microCHP. This scheme aimed to encourage the deployment of renewable energy technologies at the local level. It also empowers individuals and communities to generate their electricity.

Overall, the UK government has come up with several different incentive schemes to reward renewable energy generation.

B.1 The advantages of using DFIGs for wind generation

Doubly-fed induction generator occupies a certain percentage of applications in the field of wind power generation because of its unique advantages.

First of all, both the rotor and stator of the doubly-fed induction generator can be connected to the grid, which means that it is efficient in energy generation. The stator output power of doubly-fed induction generator has constant frequency and constant voltage alternating current, so it can be directly integrated into the grid. The slip power of the rotor can also be injected into the grid. As a result, this type of generator enables the efficiency of energy conversion.

Secondly, compared with synchronous generator, doubly-fed induction generator only needs to control the power at rotor for frequency conversion, and the rotor power is generally within 20% of the total power. So it only needs small rectification inverter capacity, hence the cost of inverter is low. At the same time, its frequency conversion loss is low, and the scale of control system is small.

Third, due to the fact that the wind speed varies in real-time, the amount of high-frequency harmonics emitted by doubly-fed induction generator when running at variable speeds is low, which means that the wind energy is highly utilized. The electricity generated by synchronous wind turbines will generate high-frequency harmonic currents flowing into the power grid during the rectification and inverter process, which will worsen the quality of the power grid, thereby affecting the utilization efficiency of wind energy. Therefore, the utilization efficiency of doubly-fed induction generator is relatively better.

Finally, the speed of the doubly-fed induction generator is controlled by the frequency converter connected to the rotor. When the wind speed is high, doubly-fed induction generator is unlikely to cause its rotor to fly, so it has high reliability. In contrast, the speed of a synchronous generator is determined by the external wind speed, and when the wind speed is high, it will cause the generator to fly, thus affecting its reliability.

In general, a doubly-fed induction generator has several advantages in wind power generation. Its advantages of efficient energy conversion, economic practicality, high utilization efficiency and good reliability make it have a place in the field of wind power generation.

B.5 The consequences of connecting new DG capacity on network fault levels and protection

In the past, the distribution network is radial and has only a single source, which were relatively easy to maintain. However, the introduction of DG changed its original structure, leading to a change in the direction of power flow in the network. After DG is connected, the distribution network will form a situation of multiple power sources.

If a problem occurs at the end of the bus, it is very likely to cause faults in both the DG and the main power sources. Based on this, it can be expressed as $I_f = I_s + I_g$. Where I_f represents the fault current; I_s represents the short-circuit current of the main power source; and I_g is the short-circuit current of the DG. Due to the presence of DG, I_f is likely to increase, and for the protection of the distribution network, relay protection will automatically cut off the faulty line to ensure the safety of the distribution network. If I_f increases sharply, it may exceed the limit that the device can withstand, which will cause other devices to cut off the line under this condition, thereby causing the range of other faults to increase.

In addition, if a protection device in the middle of the bus fails, although I_s and I_g may not have very obvious changes, since the voltage of the DG is much lower than the voltage of the main power source. If the fault point is provided with voltage for a long time, the line voltage will be greatly reduced, causing the distribution network to face partial collapse. Therefore, after the introduction of DG, the negative impact on power source protection will be very obvious. If the fault is not properly handled, it is very likely to cause an area of faults and power outages to continuously expand or even cause partial and large-scale collapse of the network.

After the connection of DG, if a fault occurs in the line, the protection action can only isolate the fault point from the main power source, and the DG can still provide fault current through the line, which will generate a sustained electric arc, and even damage the insulation layer of the protection device, expanding the fault and making what should be a brief recovery into a permanent fault.

The introduction of DG will affect the coordination between reclosing and relay protection devices. In the event of a fault, the increase in short-circuit current due to DG sources will reduce the power at the reclosing position, causing the fuse wire to act first in an instant, thereby disrupting the normal coordination between reclosing and the protector.