Economic Operation and Control of Power System

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Week - 09

Lecture – 43

Hello and good morning everyone, welcome you all for the NPTEL online course on Economic Operation and Control of Power Systems. Today we will continue our discussion with respect to optimal power flow. So I will give you an overview about linear sensitivity analysis. So linear sensitivity coefficients indicate the change in one system quantity as another quantity is varied because it is a power system, there are lot of dependent variables and independent variables. So now it says that what is the dependency on if change in one system quantity that will lead or affect another quantity in a system. Example change in line flows, bus voltages, etc. due to variations in generator outputs, timer tap settings and so on and so forth. These linear relationships are essential for the application of linear programming. Example a commonly used method to incorporate security constraints into the OPF is linear sensitivity factors. So linear sensitivity coefficients are expressed as partial derivatives.

You see here linear sensitivity coefficient, this is one of the examples. So change in line flow between a bus which is I and bus which is J that means there is a line connected between bus I and bus J and there is a flow which is happening and that is expressed in terms of MVA. And there are some bus which is having a generator which is termed as K. Now if you change the generation output of this generator, how it is affecting line flow of the bus I and J, line which is connected between bus and I, J. So this is what is linear sensitivity coefficient.

So this is very helpful for us bus because by looking at this coefficient term we will get an idea, how much sensitive is this specific line with respect to a change in generator output at some other bus. So LSE shows the sensitivity of the flow with respect to the power generated bus K. So create contingency constraints so that the resulting OPF solution will not have any overloads if any line outage occurs. So uses the compensated line outage distribution factor developed in the security analysis chapter, we have discussed about this, generation output outage factor and line outage distribution factor. So the only practical solution is to solve with no contingency constraints and find out if any contingency causes overload.

Then add those contingency constraints and resolve. First solve without any contingency constraint and then find out if any contingency causes overload, then you include contingency constraints and resolve the problem. So let me take one example. Now this is a 3 bus network. So the generators connected across all the bus and certain loads.

This line impedance also been given between bus, line which is connected between bus 1 and 2, line which is connected between bus 1 and 3, line which is present between bus 2 and 3. So these are set of quadratic expressions determining the characteristics of fuel output with respect to their power output, fuel input with respect to their power output and there are certain constraints, limits, let us say lower limit and upper limit of individual generator. Now ignoring losses by using Lagrange multiplier, solve them. It is very straightforward problem and to deliver a total load of 850 megawatt. So you see here, I am speaking with respect to the whole system.

There is 200 megawatt of load connected bus number 1, 558 bus number 2 and 100 at bus number 3. Put whether this 850 megawatt of load that need to be met by all these 3 generators. So you would get this as the generation output where economic dispatch is considered as a objective function without considering any losses. So you will get Lagrange multiplier of 9.148 dollar per megawatt hour.

Now BX matrix is formed using the line reactance as follows. Now BX matrix is just a susceptance matrix and it is very straightforward. This is line reactance between bus 1 and 2, line reactance between bus 1 and 3. You add all of them as a diagonal entry. Off diagonal is just negative of reactance which is present, inverse of the reactance which is present.

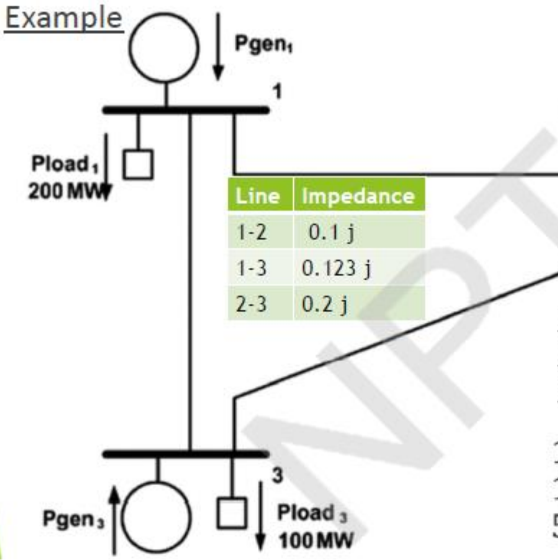
So you will get this susceptance matrix for this 3 bus network. Now just to, it is a mathematical adjustment to keep the power flow injections in megawatt, we multiply by 100 each of the entries. Now the expression for the Lagrangian with the power flow equations return out becomes, this is the Lagrangian function, this is the total fuel cost, this represents the fuel cost, A plus BP plus CP square, that need to be minimized, plus there are certain constraints, lambda 1, lambda 2, lambda 3. So lambda 1 is the total power generation of generator 1 and corresponding load at generator 1, bus 1. Bus 1 should be 0.

I mean it should be same. The difference between them should be 0. And then similarly at generation lambda 2 corresponding to the generator 2 and lambda 3 corresponding to the generator 3. You can see here this is Bx into theta represents power output basically. Bx into theta represents power output.

If you see here, P is 1 by x into theta. 1 by x is nothing but 2, nothing but B. That is what we have got this. So B into theta represents the power output. So these are all generator power outputs with respect to individual angles.

So now you get set of, you know, equal constraints which are associated with individual Lagrangian multiplier and this represents, lambda 4, this represents the slack bus, theta 1 minus 0. You ensure that the phase angle of slack bus is 0. Now considering that you get this solution. Now whatever we have done in using Lagrangian multiplier, we are just getting the same results in a way. Why we are doing this? So that we can eventually add one more constraint which is line flow limits.

- Example



Line	Impedance
1-2	0.1 j
1-3	0.123 j
2-3	0.2 j

$F_1 = 7.92P_1 + 0.001562P^2 + 561$ Rs/h
$F_2 = 7.85P_2 + 0.00194P^2 + 310$ Rs/h
$F_3 = 7.97P_3 + 0.00482P^2 + 78$ Rs/h

$150 \leq P_1 \leq 600$ MW
$100 \leq P_2 \leq 400$ MW
$50 \leq P_3 \leq 200$ MW

- Ignoring losses a delivery of 850 MW resulting in a dispatch of
  $P_1 = 393.2$ MW
  $P_2 = 334.6$ MW
  $P_3 = 122.2$ MW

Is obtained using Economic Load Dispatch and the Lagrange multiplier is 9.148 $/MWh

- B_x matrix is formed using the line reactances as follows

$$B_x = \begin{bmatrix} \left(\frac{1}{x_{12}} + \frac{1}{x_{13}}\right) & -\frac{1}{x_{12}} & -\frac{1}{x_{13}} \\ -\frac{1}{x_{12}} & \left(\frac{1}{x_{12}} + \frac{1}{x_{23}}\right) & -\frac{1}{x_{23}} \\ -\frac{1}{x_{13}} & -\frac{1}{x_{23}} & \left(\frac{1}{x_{12}} + \frac{1}{x_{23}}\right) \end{bmatrix} = \begin{bmatrix} 18 & -10 & -8 \\ -10 & 15 & -5 \\ -8 & -5 & 13 \end{bmatrix}$$

We are coming out with a more generalized expression. You see here, you got earlier 393, 334 and 122 using Lagrangian multiplier. So you will also get nearly the same results 393, 334 and 122. Now you got theta, the lambda is also same, 9.1483. And now you can calculate the power flows. You got the power flows across the different lines. Now you can insert this constraint. Let us consider for time being the constraint of power flow between line 1 and 2, between, you know, the line which is connected between bus number 1 and 2 and the limit will be set to 150 megawatt. What is the power flow that is happening through this line earlier? It is 158.776. Now we are putting some constraint, 150 megawatt. Now the added constraint is, this is just a multiplier, 1 by x, that means this is a power basically, 1 by x into theta 1 minus theta 2, DC power flow. This is nothing but 150. Now this is a constraint. Because of which you will get one more Lagrangian multiplier, lambda 5 let us say.

- To keep the power injections in MW, we multiply by 100

$$B_x = \begin{bmatrix} 1800 & -1000 & -800 \\ -1000 & 1500 & -500 \\ -800 & -500 & 1300 \end{bmatrix}$$

- The expression for the Lagrangian with the power flow equations written out becomes

$$\mathcal{L} = \sum_{i=1}^{N_{bus}} \left(a_i + b_i P_{gen_i} + c_i P_{gen_i}{}^2\right)$$
$$+\lambda_1\left(100B_{x11}\theta_1 + 100B_{x12}\theta_2 + 100B_{x13}\theta_3 - P_{gen_1} + P_{load_1}\right)$$
$$+\lambda_2\left(100B_{x21}\theta_1 + 100B_{x22}\theta_2 + 100B_{x23}\theta_3 - P_{gen_2} + P_{load_2}\right)$$
$$+\lambda_3\left(100B_{x31}\theta_1 + 100B_{x32}\theta_2 + 100B_{x33}\theta_3 - P_{gen_3} + P_{load_3}\right) + \lambda_4(\theta_1 - 0)$$

Now, after calculating that, now the power flow changes. You need to anyway maintain the load flow. That means some of the generation is equal to load. 850 megawatt need to be met. Now because you have put a bar between bus number 1 and 2, only 150 can flow.

Through some other means it will be rerouted so that you will maintain this 850 megawatt of load. Now you can see that here. This is a set of new generations that you get because of the new constraint being added and because of which you see here, there is a change in generation, 382 is the new generation. I will just place 393, 334, 122. Earlier one is 393, 334 and 122 nearly.

You see here there is a change in generation with respect to each of them, each of them, each of the generators. And because of which let us also put up the previous line flow results here. 158, 34 and minus 56, 57.2. Minus 57 indicates the power flow direction is opposite basically.

- The solution to this set of equations

$P1$ = 393.1698 MW

$P2$ = 334.6083 MW

$P3$ = 122.2 MW

The lambda values are $\lambda_1 = \lambda_2 = \lambda_3 = 9.1483$

- And the line power flows are

$$P_{flow_{12}} = 158.776$$
$$P_{flow_{13}} = 34.9922$$
$$P_{flow_{23}} = -57.2186$$

- Add a constraint to the system representing the flow limit on line 1–2. The limit will be set to 150 MW.
- The added constraint is $\frac{100}{x_{12}}(\theta_1 - \theta_2) = 150$
- Solving the LaGrangian

$P1$ = 382.7244 MW

$P2$ = 345.4528 MW

$P3$ = 121.8228 MW

And $\lambda_1 = 9.1156, \quad \lambda_2 = 9.1904, \quad \lambda_3 = 9.1444$

$$P_{flow_{12}} = 150.0, \quad P_{flow_{13}} = 32.7244, \quad P_{flow_{23}} = -54.5472$$

That means the power flow positive is happening between 3 to 2, right? Because there is excess load being seated at bus number 2, 550 megawatt. Now let us discuss further with respect to SCOPF, Security Constrained Optimal Power Flow, Constrained Computation of Sensitivity. You see power injection and bus number I are given by, so this is a generalized expression, active power flow and reactive power flow. That is real part of the apparent power which is nothing but V into I conjugate basically, right? So that is what we are trying to do.

We are splitting it. So this is with respect to bus number I. So you see here whatever there is a power flow between bus number I and J is considered in this expression.

- Power injections at the bus I are given by,

$$P_i = Re\left[\sum_{j=1}^{n} V_i\left[\left(V_i - t_{ij}V_j\right)y_{ij}\right]^* + V_i\left(V_i y_{shi}\right)^*\right]$$

$$Q_i = Im\left[\sum_{j=1}^{n} V_i\left[\left(V_i - t_{ij}V_j\right)y_{ij}\right]^* + V_i\left(V_i y_{shi}\right)^*\right]$$

Where, t_{ij} = transformer tap ratio in branch ij

y_{ij} = branch admittance

y_{shi} = total shunt admittance at bus i (assuming π model of transmission lines)

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- At each bus, $P_i = P_i(\bar{V}, \bar{\theta}, \bar{t})$ and $P_i = P_i(\bar{V}, \bar{\theta}, \bar{t})$
- Where, $\bar{V} = [V_1, V_2, \dots V_n]^T$, $\bar{\theta} = [\theta_1, \theta_2, \dots \theta_n]^T$,

$\bar{t}$ = vector of transformer tap ratios

And there is also a local element. There could be local load consumption and that is being addressed by this expression. V I into V I, that means basically V square by R.

What is that? V square into, otherwise you can say like this, V square into admittance, right? V square into admittance, shunt admittance. That is it. So that is the self power flow, the local power flow. This you can see here, there is a bus voltage. We are speaking with respect to bus I.

So V I is that bus voltage and there is a current which is happening between that bus and any other bus. It depends upon whether the line is connected between that bus to any other bus in the network or not. What is there? See T I J is transformer tap ratio in branch I J. Now let us say this is just an integer.

This is just an integer. This represents the difference in voltage V I minus V J, V I minus V J into Y I J. So that means difference in bus voltage into that admittance is what the current which flows because voltage into admittance will give you current. That means I, that means this is nothing but I and star. That means V I into I I J star, something like that.

I I J star. So this and what, this is just apparent power. That means it includes active and reactive component. So we are separating it out. To see to it that you have a sort of real part which represents active power flow and imaginary part which represents reactive power flow. The same thing I have just put up here again.

Now at each bus P I is depending upon these three things, voltage, phase angle and transformer tap position. This is just a vector basically finally. And where V is the total voltages, whatever is there. It is a voltage vector basically.

This is a voltage vector angle vector. So all those voltage of individual buses V 1, V 2 up to V N. Similarly, phase angle and T represents vector of transformer tap ratios. Now we are just moving towards more generalized expressions. Let U bar from U 1 to U N be the control variables. U is a general term if you remember some state space equations. X dot is equal to A X plus B U. And Y is nothing but C X plus D U. This is a very simple state expressions. So X is the state variable, Y is the output. A B C D are matrices.

X represents, I already told state variable. U represents the input. So this is a general understanding. So here we are considering they are the control variables. As such as a generator outputs, transformer taps, VAR device outputs, etc. There could be shunt capacitors and all these things.

These are the control variables through which you can carry out some control action. You can change the transformer taps, you can change the reactive power settings of the VAR devices or you can change the generator outputs and all these things such that you will meet out a specific objective. And X bar is the state variables. What are the state variables? Voltage and phase angle. State variables are those variables by knowing them you will get to know the overall power flow and other things.

So what are those critical state variables are voltage and phase angle? So because active power is depend upon voltage, theta, reactive power is also depending upon voltage and theta. Now let H bar, another vector from H1 to HM. So be the transmission system dependent variables such as MVA flows whose sensitivity we wish to find with respect to changes in the control variables. So the line limits, see ultimately we are trying to figure out the dependency on this dependent variables which are line flows and other things upon the individual change in control variables. That is what in the beginning we have defined sensitivity factor.

What it depends? If change in line flow, when you see there is a change in power output at some specific generator. That is what we are trying to find out a mathematical representation of it. So we can see here H bar can be expressed as:

- Changes in $\bar{h}$ is $\Delta\bar{h} = \begin{bmatrix} \frac{\partial f_{h1}}{\partial x_1} & \frac{\partial f_{h1}}{\partial x_2} & \cdots & \frac{\partial f_{h1}}{\partial x_n} \\ \vdots & \vdots & & \vdots \\ \frac{\partial f_{hM}}{\partial x_1} & \frac{\partial f_{hM}}{\partial x_2} & \cdots & \frac{\partial f_{hM}}{\partial x_n} \end{bmatrix} \Delta\bar{x} + \begin{bmatrix} \frac{\partial f_{h1}}{\partial u_1} & \frac{\partial f_{h1}}{\partial u_2} & \cdots & \frac{\partial f_{h1}}{\partial u_n} \\ \vdots & \vdots & & \vdots \\ \frac{\partial f_{hM}}{\partial u_1} & \frac{\partial f_{hM}}{\partial u_2} & \cdots & \frac{\partial f_{hM}}{\partial u_n} \end{bmatrix} \Delta\bar{u}$

$$\Delta\bar{h} = [J_{hx}]\Delta\bar{x} + [J_{hu}]\Delta\bar{u}$$

- The dependent variables can be expressed as functions of state and control variables

$$[J_{hx}]\Delta\bar{x} = [J_{hu}]\Delta\bar{u}$$

- Therefore, $\Delta\bar{x} = [J_{hx}]^{-1}[J_{hu}]\Delta\bar{u}$
- Using the above equation, $\Delta\bar{h} = \left[[J_{hx}][J_{hx}]^{-1}[J_{hu}] + [J_{hu}]\right]\Delta\bar{u}$. This gives the linear sensitivity coefficients between the transmission system quantities, $\bar{h}$ and the control variables $\bar{u}$.

- For a multi-objective OPF that minimizes fuel cost, real power loss, and voltage deviations at the buses (VAR planning) the objective function may take the following form

$$F_T = \omega_1 \sum_{i=1}^{N_G} (a_i P_i^2 + b_i P_i + c_i) + \omega_2 \sum_{i=1}^{N_l} g_l \left[(e_i - e_j)^2 + (f_i - f_j)^2 \right]$$

$$+\omega_3 \sum_{i=1}^{N} (V_i - V_{i,\,nom})^2$$

Where, $V_{i,\,nom}$ = is the nominal voltage at the bus i.

a function of state and control variables as shown below. So this dependent variable depends upon state variable as well as control variable.

Now in terms of matrix representation. Now we will see there is a perturbation in H dependence on the dependent variables. That is H is perturbed to delta H. So that is as mentioned here as now you obtain partial differential equation. This is sensitivity part that we are bringing in here, sensitivity coefficients. H1, dou F H1, dou F H1 by dou X1, dou F H1 by dou X2, dou F H1 by dou Xn.

That means dependent, 1 to M, M dependent variables. So with respect to each dependent variable we are trying to find out its dependency on corresponding state variable. So first entry could be dou H line flow. Let us say there is a line flow dou H I12.

This is a line which is connected between bus 1 and 2 and dou V1. Similarly and then you do it for and the first row of the matrix contains all those entries where there is a dependency on this particular dependent variable with respect to every state variable.

Then dou H12, the next column entry could be dou H12, dou V2. Similarly dou H12, dou theta n, whatever last variable like this. Similarly you do it for all the dependent variables. So that is this matrix basically and that is multiplied by delta X total state variables and then similarly you do it for all the control variables. Dou U1, dou U2, dou Un. What are the control variables? The transformer tap positions and where settings and all these things and that is multiplied with the control variable.

So that means in a way you get in short this expression which is delta H is JHX. JHX is this dependence matrix of dependent variable with respect to state variable multiplied by delta X plus dependent matrix of dependent variable with respect to control variable which is JHU into delta U. Now you got this expression. Now this can be further reduced by considering JHX delta X is equal to JHU delta U. So there is also an interconnection between state variable as well as the control variable because when you change the control variable that will also have an effect on the state variable.

That means if you change the transformer tap position, there will be also change in voltage and phase angle seen. So then you can express as delta X is nothing but JHX inverse into JHU into delta U. Now you put this back to this expression, you get this overall matrix where you can single handed, you can just directly relate dependent variables with respect to control variables. Line flow with respect to change in tap changes, change in expression in terms of where settings and other things. So this gives the linear sensitivity coefficients between the transmission system quantities H and control variables U.

Now in a security constrained optimal power flow ACOPF, the control variables are adjusted in such a way that the security margins are maintained. It may be desired to ensure the security of the system even after a contingency occurs. So security constraints for such post-constraints, contingency conditions also can be included in a security constrained OPF. A commonly used method to incorporate the security constraints into the OPF is the use of linear sensitivity factors. So in this flow chart, I will try to understand the overall algorithm basically.

So solve first the base OPF with all limits met. This represents either DC OPF or FOST coupled load flow analysis, FDLF. Because if you remember in the last class, we are trying to shortlist, shortlist the most critical events, most critical outages, contingency cases. So you do the base OPF and then do the contingency screening algorithm. And for all possible outages, line outages and the generator outages, now you find out the most critical of them.

That means add m worst contingencies to contingency list. Now you shortlist them because not all outages are very critical. That is what we have discussed. Now you prioritize them out of let us say 100 combination and let us say you shortlist 10 or 20, the most critical one based on the initial screening that you do using DC OPF or FOST coupled load flow. Now you have got all the set of critical contingency cases. Now you solve AC power flow for considering one at a time each contingency, one at a time each contingency based on the priority list.

That means first contingency case is the most critical one as per the result you have got using DC OPF. Now you do the AC OPF, then you get certain constraints, contingency constraints, certain contingency constraints you get. And in fact using DC OPF also you had got certain contingency constraint. When you have done the DC OPF then also you might have got some contingency constraint. Now we are updating that using AC OPF because AC OPF is even more accurate than the DC OPF.

Now you got certain contingency constraint, contingency constraint could be this specific for this specific top prior line outage, the effect in the different buses and their constraints that is been added here. Let us say for example, the first priority could be line outage between bus number 1 and 2, right? There is a line which is connected between bus number 1 and 2 and this is considered to be the most critical one as per DC OPF. Now you take that and you carry out the AC OPF, carry out the AC OPF for the entire network. Now you get certain contingency constraints. In the sense for this specific case then the contingency constraints could be line, I mean power flow violation between let us say bus number 20 and 23.

And there could be violation in power flow between bus number 30 and 35, like this as a 10 constraints that you have got. Then you say you should not supposed to increase this power flow beyond this limit and there is a constraint that you put. Let us say 150 megawatt is the bar here and then it could be something else, increased. So what we are trying to say is using AC power flow we get more accurate constraints list as compared to you might have got using DC OPF.

That is why you are doing AC OPF. You could have done AC OPF for all of them individually in the beginning itself but that would have taken more time. Now you are doing it for the most critical things. Now you get all of them, all possible contingency constraints for individual case outages, contingency outages. Now you make a union of these sets because there could be you know overlap among different contingency constraints because you are trying to solve individually.

Now you get a set of different sets, subsets, you make a union of these sets. So in a way it is similar to you know sort of if you can recall network theory there is a specific theorem, superposition theorem. What we used to do is you know if there are so many voltage source and current source, considering one voltage source at a time you find out what are the power flow lines and current flow which is happening. Then you remove that voltage, then connect current, only one current source, similar to that case. Now you get set of all the constraints and which are more accurate considering all possible contingency case studies. Now you get the final list of contingency constraints and then for them you carry out OPF again, put together everything.

Now it is a more reduced one. You should have, actually this should have been done in the beginning itself but you do not know what are those constraints basically. So all these process is done to find out those critical contingency constraints. Now then monitor convergence criteria. If it is converged or not, if it is not converged then you change the control variables, you change the control variables like transformer tap position, you know reactive power limits or you know so such that for in the next iteration they may get converged because once you change the control variables there will be change in state variables.

ACOPF means was, let us say for example Newton Raphson load flow. How do you change in the, how do you arrive at the convergence? You will change this theta, right? Theta and voltage. Theta is changed to theta plus theta 2, let us say second iteration. Theta 1 plus delta theta, V2 that means voltage is nothing but updated voltages V1, first iteration plus delta V. So this is what is we are trying to do. So you change something so that theta and delta, theta is changed to theta plus delta theta, voltage is changed to V plus delta V and then you carry out the ACOPF so that ultimately you will get converged results.

Then once it is satisfied then obtain optimal power system operating states with contingencies. Then you say for these possible contingency case studies putting this as a bar will be helpful to maintain system stability. You understand? Now the optimal power flow problem can be solved for more than one objective. For example in addition to the fuel cost minimization which is general economic dispatch problem statement it may be desired to minimize real power loss, voltage deviation at the buses etc.

The formulation of the OPF is then done for multiple objectives as shown below. That means minimization of fuel cost that means W1 into F1, W2 into F2, WM into FM where F1, F2, FM are M different objective functions altogether now and W1, W2, WM are the weights assigned to the corresponding objective functions. So here F1 may represent objective function could be cost minimization, F2 could be loss, F3 could be voltage limits and so on and so forth. By varying Wi's it is possible to assign differential importance to the objective function. That means you can put a weightage on individual objective function. You understand? Let us say for a specific transmission system operator he is more concerned towards loss minimization then he may try he may adjust here and there with respect to fuel adjust you know increase in fuel consumption.

So cost associated with that and other things. It depends upon individual system operator at a specific time. Even for a individual system operator at different time of event the priority may change. So he would change his the weightage such that he would arrive at a required point. So for a multi-objective OPF that minimizes fuel cost, real power loss and voltage deviations at the buses.

The objective function may take the following form. So this is what we were discussing. So weightage 1, now this is associated with fuel economy. This is just economical, economical objective function. And here this represents what? This is V square. If you remember in the previous class we expressed in terms of rectangular and polar forms and we discussed.

This is nothing but real part and imaginary part and this is V square into conductance. This is nothing but power loss, you know minimize the power loss and this represents voltage limits. So note that the third objective is usually minimized in a wire planning problem obviously right. Usually heuristic methods such as genetic algorithms, particle swarm optimization, simulated annealing etc. are used to solve the multi-objective optimization because it is very very complicated. As you keep on adding objective functions because having one objective function itself it was so complicated considering losses and penalty factors and other things.

And adding furthermore objective functions for the entire transmission system, system is very large and the problem statement is very big and it is highly nonlinear and nonconvex problem statement. It is not straightforward ball game. What you have to do is use some heuristic methods. This is a PSO, hundreds and thousands of heuristic methods are there.

But one thing is heuristic optimization, the solution may not be trivial. That means for a set of constraints and set of variables that you consider, so each heuristic algorithm may have a different results altogether. So and finding a global optimum results is also a challenging thing because it depends upon what is the initial value at which you start and what is the total sample space and so many things are there. So there is sort of advantage that you gain with heuristic methods as compared to the conventional algorithm and there is sort of disadvantages also.

So one has to find a tradeoff point between them. So with this we will conclude the OPF part. And we will discuss in the further sessions. Thank you.