Power Network Analysis

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Week-04

Lecture-16

Lecture 16: Synchronous Generators- Parallel Operation.

Hello everyone, welcome to the first lecture of week 4 of the course Power Network Analysis, in which we will continue with our third main module, which is on synchronous generators, and this lecture is going to be the last lecture of the module on synchronous generators. In which we will discuss something about the parallel operation of synchronous generators, to be specific, the steady-state parallel operation of synchronous generators, which is inspired by the previous lecture discussion on economic dispatch, in which we understood that there are. Several synchronous generators present in the power network which are at different locations at different places compared to the load locations. Loads and generators are not placed close together; in between comes the transmission network, and each of these synchronous generators does not feed power to an isolated load. All these synchronous generators are synchronized to the power network, and in this power network, there are different loads present at different locations, so it is basically a combination of several sources and several loads exchanging power, which is essentially the transfer of power from generators to loads through this complex power network, as I mentioned. They are synchronized to the power network before power transfer actually happens.

And essentially, all these generators, they have to operate in parallel while also maintaining the synchronization aspect with respect to the system stability perspective, which we will discuss at length in the last module. Each of these units has its own economics, which we discussed at length in the previous lecture; specifically, the running costs or the operational costs are different, and the capital costs are different. generators tend to be cheaper specifically for hydro generators where there are steam turbine based generators tend to be relatively costlier compared to other units. So basically, the running cost of the economics is also different, and hence the need for economic dispatch arises while trying to figure out what the optimal schedule or dispatch of each generating unit should be while feeding a common connected load.

And we also understood or have seen that in steady state each of these synchronous generators they would either operate at 50 hertz for the all power networks except US and Canada and in US and Canada the synchronous generators in steady state they operate at 60 hertz which is the synchronous frequency and Where does this dictation of the setting of frequency come in? The setting of frequency comes from the perspective that these generators are all synchronized to the power network, and while synchronizing, maintaining or matching the system frequency with generator frequency is one important condition, and that is where 50 Hz or 60 Hz steady state operation comes into the picture. Now the issue with this philosophy from economics perspective is well taken care of in the previous lecture but there is still one more aspect, minor aspect which is still unanswered and which we will try to understand in this particular discussion is that if each such constant frequency generator which is let's say operating at steady state, if each such constant frequency generator synchronous generator, if they were to be connected in parallel and they all have to sort of supply one common connected load, Then, since these generators have to operate at the same synchronous speed as dictated by the synchronous frequency of the grid. SSo it is possible that the economics might be ensured through economic dispatch but economic dispatch as we have discussed, we discussed this for hourly generation or for a period of time where the load is not changing and that particular hour or instant was considered to be one particular interval which was one hour in the previous discussion, but as we also understand the load is not a stagnant quantity it keeps on changing. So, within one hour, let us say in 5 minutes, 10 minutes, or 15 minutes, if the load is changing and generators have to economically optimize their schedule while ensuring parallel and synchronized operation, the load sharing might appear to be uneconomic during those intermediate steps where economic dispatch cannot be done or the economic dispatch schedule is unavailable. So one possible way could be, oh, let's start doing economic dispatch every half a second, 30 seconds, half a minute, or a minute.

The computational burden involved in doing such economic dispatch in the dynamic net framework would be computationally burdensome would be very high and that's where power engineers we have come up with intermediate solution where to some extent economic dispatch solution can be avoided and still Desirable load sharing can be ensured. So that's where this notion of speed governors comes in. For proper load sharing, our synchronous generators are equipped with a special device known as a speed governor, which keeps track of the load being taken up by the generator and the synchronous speed at which the rotor is rotating. In a nutshell, the purpose of the speed governor is that when the load increases, it feeds in more power to the corresponding connected load, the corresponding rotor speed decreases slightly, and this decrease in rotor speed for a certain period of time is governed by this mechanism or device known as the speed governor. The speed governor usually has a linear characteristic; we call that characteristic the droop characteristic, whose slope is usually defined by the symbol R. R stands for the term "regulation," in a way the characteristic slope is called the speed regulation or the droop characteristic. And what does this droop characteristic look like? I mean, which is responsible for the principle behind the operation of speed governors. The droop characteristic looks something like this, as shown in this particular graph. The value R, or the slope R in percentage, is usually the change in frequency as a percentage divided by the percentage change in real power. And FNL, which is the term sitting over here or given over here, we call that to be the no load frequency.

$$Perecentage\ R = \frac{\%\ frequency\ change}{\%\ real\ power\ change}$$

Now the no-load frequency of a given synchronous generator can be different depending on the design of the speed governor as well as the synchronous generator itself. So in a way, if let us say I have to find the value of slope R as per this formula, what I can do is, probably I can figure out two unique points on this droop characteristic. One such point is already available to me. So, if I have to let us say mark the coordinate of this particular point with real power on the x axis and frequency of the generator on the y axis, this coordinate is nothing but 0 comma FNL where FNL is the no load frequency of generator and 0 refers to the no load condition. It is a generator, so it cannot generate anything less than 0. 0 is the most ideal condition for a no-load condition. And suppose now we also know a point which, let us say, refers to the full load condition. In the full load condition, the full load frequency is going to be less than the no load frequency. The reason is that as the frequency of the generator goes down, the kinetic energy stored in the rotor would also go down. Rotor being a rotating device it also has its own mechanical inertia and it has its own angular momentum.

So, for rotating devices, the kinetic energy is proportional to the square of the speed of that particular rotating device. So, if the speed tends to go down the rotor kinetic energy tends to go down from no load condition and this release in the kinetic energy of the rotor is essentially given as a additional output to the synchronous generator to feed more electrical load. So, that is the very simple logical reason why, under no load or under full load, the full load frequency would be less than the no load frequency, and the full load power would be dictated, let us say, by the rating of the particular generator, which could be equal to Pmax, as we saw in the economic dispatch discussion. PFL, or let us say PFL, is the full load power; then what is the value of this slope R? Since we are assuming a linear characteristic for this droop operation or speed governor, essentially, if I have to, let's say, try to find the equation of this particular straight line, as shown over here, in terms of full load frequency, no load frequency, and full load power, then it's pretty straightforward in the sense. If I have to, let us say, take any general point which is P, F, which are unknowns, and P and F refer to the unknown points on this linear curve.

So P minus 0, which is the no-load power, divided by full load power minus 0 should be equal to the corresponding frequency for P, which is F, as given by this coordinate. The no-load frequency is F, NL. which refers to the zero power. For full load power, the frequency is FFL, and then we also have the full load, the no load frequency for zero as FNL. Remember, the denominator here is going to be a negative term.

Also, the numerator over here is going to be a negative term, so this ratio, in a way, the overall ratio becomes positive. So if we now rewrite this equation, it would appear to be equal to P is equal to PFL multiplied by FNL minus F divided by FNL minus FFL and if we focus on the term which is written over here compare this with the definition of the droop speed regulation then it would pretty well it is pretty obvious that the value of R is nothing but FNL minus FFL is equal to PFL.

$$\frac{P-0}{P_{fl}-0}=\frac{f-f_{nl}}{f_{fl}-f_{nl}}$$

$$P=P_{fl}\left(\frac{f-f_{nl}}{f_{fl}-f_{nl}}\right)$$

So if we know what the value of R is, which is determined by the full load frequency and the full load power of the generator, then our power expression or the linear characteristic would be simply written as P is equal to FNL minus F by R.

$$P=\frac{f_{nl}-f}{R}$$

This simple equation is the basic equation for the droop characteristic determined or governed by the speed governor, which is essentially what is also mentioned here. Depending on whether the synchronous generator is connected to an infinite bus where synchronization has already happened.

So during post synchronization, frequency cannot change or frequency should not change. And that's the reason why the droop characteristic for an infinite bus is a flat line or a line that is parallel to the P-axis, which is also shown here in the next slide. So F naught essentially is the frequency that is dictated or governed by the grid frequency or the infinite bus. If now we connect a synchronous generator to a infinite bus and after synchronization we want to understand or find what should be the power output of the synchronous generator, then this power output can essentially be determined by the common operating point dictated by the droop coefficient of the infinite bus which is the plot on the left hand side over here and the right hand side is actually the droop characteristic of the physical synchronous generator So F0 is the frequency of the infinite bus, and the synchronous generator is synchronized to the infinite bus at frequency F0. So P0 would be the corresponding power delivered by the synchronous generator at this particular F0 frequency.

So if we reuse our previous equation, which is shown over here, then P0 is nothing but the no-load frequency of the generator minus the synchronous frequency of the infinite bus, divided by the slope R. R is usually a positive number or a non-zero number for a practical generator, whereas the slope would be zero for an infinite bus because the infinite bus frequency will not change no matter how the load changes or generation changes. So that's where this formula comes in for power output of a synchronous generator synchronized to an infinite bus. Now this is, so far, the simple case where we have one generator connected in parallel to an infinite bus. Things become a little interesting or a little complicated when we understand this operation of two generators operating in parallel. If we understand how two generators operate in parallel, we can also extend this discussion to understand the parallel operation of multiple generators. So what I have considered in this particular case is there are two individual synchronous generators which are connected in parallel and for time being we don't have the infinite bus into consideration and based on the load which these two generators are sort of satisfying together. So let's say if the load is equal to Pd then the power output of generator 1 which is this number plus the power output of generator 2 should be satisfying this common load Pd$(P_1 + P_2 = P_{D})$. And using this, can we find what the value of F0 is? Because there is no load frequency for individual generators, they would be specified by the corresponding manufacturers as per the speed governor. The corresponding speed regulations would also be defined according to the individual speed governor definitions or manufacturer specifications.

So, if we have to find F0, is there a way to determine the common frequency at which these two generators are operating in parallel? So yes, let's try to see how we can find it. If you recollect, then for generator 1, P1 should be nothing but Fnl1 minus F0 divided by R1. And similarly, P2 would be nothing but Fnl2 minus F0 divided by R2,

$$P_1 = \frac{f_{nl1} - f_0}{R_1}$$

$$P_2 = \frac{f_{nl2} - f_0}{R_2}$$

In which Fnl1, Fnl2, R1, and R2 are known. The unknown is F naught, which is common in both terms. We also know what the common load is that these generators are satisfying or trying to satisfy. So if we substitute these expressions here we will essentially have one equation where there would be one unknown which is F naught and by rearranging the terms we can then find the common expression of F naught in terms of all known quantities. Now, so far, things are pretty straightforward, given a particular load that two generators in isolation are trying to deliver while operating in parallel. So this would be the common frequency of both generators at which they are operating. Now, from this instant, let us try to understand that if, suppose, the demand which was earlier PD has now been incremented by a value delta PD. The load has increased; the demand has increased by a quantum delta PD, which is also known.

So, if the demand has gone up then as we if you remember or recollect our previous slide discussion where we discussed that as the load would go up the rotor speed would momentarily go down, so kinetic energy of the rotor would go down, essentially it would release some of its kinetic energy from a prior unloaded condition to a loaded condition, so that is extra kinetic energy can go to meet the particular load for some period of time. Since that demand has marginally increased, what is the expectation? With respect to the value F naught. Should the new frequency be less than F naught for the total demand of PD plus delta PD, or should it be higher than F naught compared to this increase in demand? The answer is pretty simple. Since the demand has gone up, delta PD is positive. Both of these generators would try to increase their generation, which would happen only when the rotor speeds tend to momentarily go down. So essentially, the new frequency would decrease. So let's try to find or understand what that new frequency would be. If the demand has increased by delta PD on similar lines, we can also assume that the new frequency F dash would be F naught plus delta F. We are assuming delta pd to be positive, indicating an increase in load. Delta f, on the other hand, should theoretically be a negative number, but let us not worry about its sign for the time being.

We assume delta f to be a general symbol or variable that could be positive or negative depending on the group characteristics of individual generators. So if the new frequency is f naught per delta f and we know f naught from this particular expression. So we can probably do a similar exercise to what we did over here to find what delta F should be. So let's write those equations. So the new generation of generator 1 would be equal to Fnl1 minus F naught minus delta F by R1, and we also have R1 here.

$$P_1' = \frac{f_{nl1} - f_0}{R_1} - \frac{\Delta f}{R_1}$$

Similarly, the new generation of generator 2 would be F NL2 minus F naught divided by R2 minus delta F divided by R2.

$$P_2' = \frac{f_{nl2} - f_0}{R_2} - \frac{\Delta f}{R_2}$$

How am I writing negatively here? Remember, the new frequency is F dash. So the new generation P dash should be F NL minus F dash by R. So if I don't associate any sign with delta F, the minus goes from here, and when you multiply it, it reflects as a negative number here. And now, P1 dash plus P2 dash, which are new generations, should satisfy the new demand also.

$$P_1' + P_2' = P_d + \Delta P_d$$

So if I substitute these numbers, what do I see? I would see that Fnl1 minus F0 equals R1 plus Fnl2. Fnl2 minus F0 by R2 minus delta F R1 inverse plus R2 inverse is equal to PD plus delta PD. This is my new equation where delta PD is known and delta F is the only unknown; F0 and the remaining quantities are known. Now, if I compare the first two terms with the term on the LHS over here, which is PD, what do you think? Are they equal or unequal? They appear to be all equal thanks to the previous equation from which we found F0. So in a way, the change in frequency is delta PD negative by R1 inverse plus R2 inverse which in a way also results or says that if the demand has gone up the new system frequency would be lesser than the previous frequency because delta F is a negative number we are assuming delta PD to be positive and R1 and R2 are also positive quantities.

$$\frac{f_{nl1} - f_0}{R_1} + \frac{f_{nl2} - f_0}{R_2} - \Delta f(R_1^{-1} + R_2^{-1}) = P_d + \Delta P_d$$

$$\Delta f = \left(\frac{\Delta P_d}{R_1^{-1} + R_2^{-1}}\right)$$

So the frequency would tend to go down, and this would be the new expression of delta F. Now, if the new frequency has gone down, can we not also find what the change in generations would be? So if I go back and see my previous generations, then the change in generation 1 is minus delta f times R1 inverse. If I substitute delta f from here, then this is equal to delta PD times R1 inverse divided by R1 inverse plus R2 inverse. And similarly, delta P2 dash, which is the change in generation of unit 2, is delta PD R2 dash inverse by R1 inverse plus R2 inverse, which says that the change in generation load, which was by delta PD, has been taken up by the two generators, generator 1 and generator 2, which are in the ratio of inverse proportion of their respective droop characteristics; this means if a generator has a higher droop characteristic. It would tend to participate less while the load is changing.

$$\Delta P_1' = \Delta f R_1' = \frac{\Delta P_d R_1'}{R_1^{-1} + R_2^{-1}}$$

$$\Delta P_2' = \Delta f R_2' = \frac{\Delta P_d R_2'}{R_1^{-1} + R_2^{-1}}$$

A generator whose droop characteristic is smaller means its release of kinetic energy can be greater. So that particular generator would tend to increase or take on more load sharing. All that is, in a way, summarized in this particular slide. So, the demand has now increased by delta PD. The change in frequency is negative of delta PD and sum and inverse divided by the sum of inverse of individual values.

$$f' = f_0 - \frac{\Delta P_d}{R_1^{-1} + R_2^{-1}}$$

Speed regulation coefficients and the new power changes or new load sharing are the terms that we saw in the previous slide. So in a way, the load increments shared by the respective generators are in inverse proportion to their respective droop constants or droop coefficients. So, in practice what happens is if we have only two such generators or multiple generators which can also be under whose parallel operation can also be understood online similar to these equations then it might appear that oh the overall system frequency would keep on going down. So, then would that not be a concern? Yes, that is a concern because if the system frequency keeps on going down as the load is increasing. Then probably our load performance will also deteriorate because remember which I mean this we have not discussed it will come up in the power flow or load flow analysis discussion that our loads are also frequency dependent, they are frequency sensitive.

If the demand for power is going up and the frequency is going down, it would mean that the frequency at the generator end or the load end is significantly poor, and hence the load itself might not be able to operate properly. So, with an increase in load, the overall system frequency is going down, and going down is not a desirable quantity. So, what is there in addition to these droop governors or speed governors that brings this frequency back to the actual desired system frequency? The answer lies in the discussion of real power control, which we discussed in the previous few lectures, week 3 lectures, wherein we understood that if the real power output of a generator has to be regulated, then it is essentially the turbine or the prime mover that has to feed in more mechanical torque or more mechanical power to the synchronous generator. The similar notion is also applied here; if a particular synchronous generator speed or frequency is going down, to bring back the system frequency or generator frequency, the turbine valves are opened, allowing more steam to push in, more water to push in, and more real power output to be generated, which in a way also shifts the corresponding speed governor coefficient or speed governor profile itself, which is essentially what is shown in this particular slide. by opening up or changing the load reference or set points the turbines or prime mover set points also change which help in shifting up the droop speed governor droop if the load is continuously increasing or this also can might be also drop down if the load is also going down which helps in resetting the generators frequency to the actual frequency this increase or shifting of the no load frequency in a way can be reflected as an additional increase or positive increase in the mechanical output from the turbine to the prime mover or through the synchronous generator.

To restore the frequency, the droop characteristic is shifted in case the load has gone up. So here, FNL dash is the new load node frequency, which is set by a control loop, and a very interesting control loop, which is in short known as ALFC. ALFC stands for Automatic Load Frequency Control or Automatic Generation Control, also known as AGC. So this control loop in itself has its own detailed discussion involved which unfortunately in this particular course we will not be able to cover or discuss. But anyone who is enthusiastic about or keen to learn more about this control loop, which helps in shifting the droop characteristics and, in a way, maintaining system economics in addition to economic dispatch, please feel free to refer to advanced textbooks or reference materials wherein you can find the dynamics involved behind automatic load frequency control or generation control.

We'll conclude this discussion today with a simple example. Wherein we consider four synchronous generators placed in a particular power plant that are all operating in parallel. Their droop characteristics are all identical, which means their speed regulation or droop value is the same, which is R, and each of these units is rated at 100 megawatts each. The governor is so designed or adjusted that these generators will produce a frequency drop of 5 Hz from no load to the desired operating condition, and at a given condition, the first three generators are each producing 75 MW at 50 Hz, while the last unit has been kept free to handle any load change that might occur, while also being given the responsibility of maintaining the overall plant frequency at 50 Hz.

So we have three conditions. The first condition is that for a load of 260 megawatts, at a frequency equal to 50 hertz, we have to find the no-load frequency of each of the four units. So let's do that first. So, given that the full load or rated power of each unit is 100 megawatts and the frequency drops from no load to the desired operational steady state by 5 Hz, we assume FSS, which represents the steady state frequency, to be 50 Hz, and the no load frequency compared to the steady state frequency is 5 Hz, so no load FNL is the no load frequency of the individual generator. So from here we can probably find the value of speed regulation for each unit. Remember, speed regulation is nothing but the change in frequency divided by the change in power from no load to full load.

So, since these numbers are all known and defined. So, this is 5 hertz, and the rated power is 500. So, 1 by 20 hertz per megawatt is the unit or value of speed governor or speed regulation or droop coefficient. For the first bit where the total load is 260 megawatt. 3 units are generating 75 megawatt at 50 hertz. So, from there if we have to find the no load frequency P given as 75 for each unit R is equal to 1 by 20. The no load frequency of the first 3 units is 53.75 hertz for 75 megawatt to be generated at 50 hertz. and the last unit which is responsible for taking up any additional load so as to maintain the system frequency as 50 Hz. Since the first three are generating 75 each, the last should generate 35 MW which in a way dictates the no-load frequency of the last unit which is 51.75 Hz. Now, why the first three units' load frequency is higher and why the fourth one unit is lower? Because the first three units are generating more power compared to this particular generator at 50 hertz again.

So no load frequency for the first three is higher. The second bit says that if this now load is incremented by 30 megawatt, while the droop coefficients and no load frequency of the generators remaining unchanged, what should be the new system frequency? So now the load has now gone up by 30 megawatt. So each of the generators will respond as per their droop characteristic. So the first three units, they have the similar characteristics. So I have multiplied three over here where the last equation refers to unit number four. The steady state frequency has now changed compared to bit A and this is the actual unknown.

The remaining quantities are known. So when we plug in those numbers, our frequency has gone down from 50 hertz to 49.625 hertz because the load has now increased from 260 to 290. And the last bit says that if the frequency has to be brought back to 50 Hz for the new load of 290 MW, what should be the new no-load frequency of 4th unit, which is in a way responsible for maintaining any load change to maintain frequency at 50 Hz. So now the new no load frequency for last unit can be easily figured out in a sense that if let's say we restore the frequency of the entire plant at 50 Hz then eventually our first 3 units will also generate 75 MW at 50 Hz because that was their set point. So in a way out of 290 megawatt if frequency is restored to 50 hertz the last unit will result in generating 30 megawatt extra which is 35 plus 35 which is 65 megawatt and it should do so at 50 hertz.

So steady state frequency is fixed at 50 Hz, this value is 65, group coefficient is 1 by 20, so from here we can find the new no load frequency. Now when we compare this new load frequency which is 53.25 Hz, earlier it was 51.75 Hz and now since the quantum of generation has gone up, the new no load frequency of last unit for 290 megawatt is comparable to the no load frequency of the first 3 units again at 290 megawatt.

That's all for today's discussion. From the next lecture, we will take up a new module, which is going to be module number four, primary module number four, which is going to be on transmission line parameters. How do we evaluate or engineeringly analyze the values of resistance, inductance, and capacitance for transmission lines? That we will discuss or start with in the next lecture.

Thank you.