Tutorial 5: Risk and Reserve

This tutorial describes risk and reserve, investigates how they are modelled, and explains the results that they produce.

Managing risk

The System Operator is responsible for ensuring that the power requirements of the load are reliably met. This includes ensuring that if the generator with the largest power output (the *risk* generator) were to suddenly become unavailable (to *trip*), then the load requirement could still be met. This reliability is achieved by ensuring that there is spare generating capacity sufficient to replace the power output of the largest risk generator.

Because the replacement generating capacity is held in reserve, it is referred to as generating reserve, or reserve. The power output of the largest risk generator is referred to as the risk. Hence it is said that reserve is scheduled to cover the risk.

Switch losses off for the reserve examples

In order to make it easier to explain risk and reserve we will take branch losses out of the equation (literally) by solving all the examples in this section with losses selected to OFF.

Risk setters

The generator with the largest scheduled power output is the risk setter, but only if it is flagged as a potential risk setter.

A set of generator offers can be for a generator that consists of a single generating unit, or they can be for a generator which is actually a generating station consisting of a number of generating units.

If a generator consists of a single generating unit then if that unit trips all of the generator's power output is lost; this generator is flagged as a potential risk setter.

However, if a generator represents a generating station that consists of a number of generating units, then provided each unit is small enough to not significantly impact the system, and provided there is no single credible contingency that could result in a significant number of units tripping at the same time, this generator (i.e., the generating station) is not flagged as a potential risk setter.

Reserve providers

If a generator trips then the power that it is was generating is lost from the power system… the total generation on the system will no longer match the total load and therefore the frequency of the electricity will drop. A certain level of frequency deviation can be tolerated, but in response to a significant drop in frequency the generators that are providing reserve will automatically increase their generation… their spare generating capacity, which is functioning as reserve, will respond by becoming generation.

If the frequency drops too low then other generators will trip, leading to a cascade failure. Hence the reserve must respond to arrest the frequency decline in a timely fashion, e.g., 6 seconds or less. Not all generators are capable of meeting this requirement; while a generator may have spare capacity, if this capacity is not able to respond quickly enough then it is not reserve and cannot be offered as such. Hence not all generators are reserve providers, i.e., while all generators have energy offers, not all of them have reserve offers.

Example of not covering the risk

Produce the result shown in Figure 139 by tapping Bus-Bus-Gen-Gen-Gen-Load-Branch, then editing the offer for gen00 to be 60MW at $65.

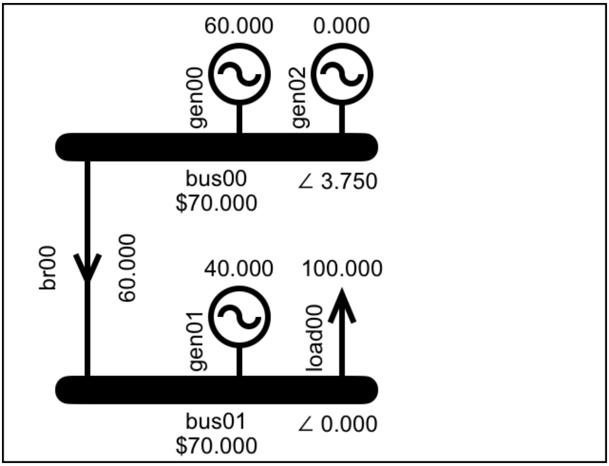
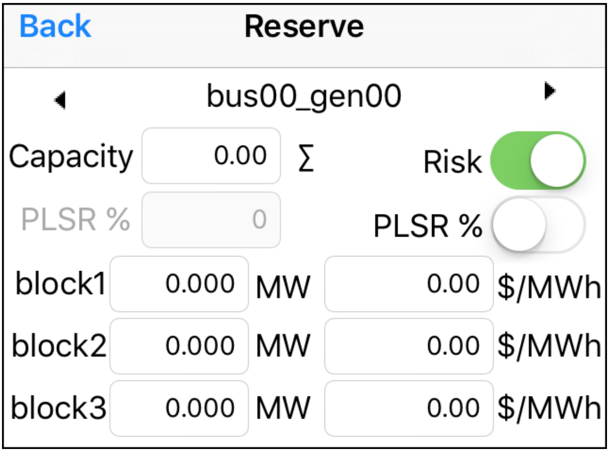


Figure 139: A model with the risk not covered

In this model we will suppose that gen00 is not a potential risk setter and also that it is the only generator capable of providing reserve. In this scenario if gen01 were to trip there would be no reserve available to replace its lost capacity in a timely fashion; gen00 has no spare generating capacity because all of its 60MW of capacity is cleared as generation, and gen02 is not capable of providing reserve.

Example of reserve covering risk

To ensure that there is sufficient reserve to cover the risk, we will now include reserve cover as a requirement in our model. The first step is to add some reserve offers.



Capacity 0.00

Risk ●

PLSR % 0

PLSR % ○

block1 0.000 MW 0.00 $/MWh

block2 0.000 MW 0.00 $/MWh

block3 0.000 MW 0.00 $/MWh

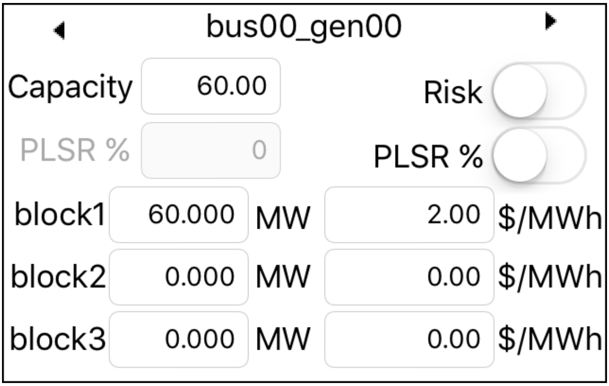
Figure 140: Reserve display for gen00 before data entry

From the gen00 Data Display tap the Reserve button. Before making any changes the Reserve display will appear as shown in Figure 140.

On the Reserve display for gen00:

- Enter a reserve offer of 60MW at $2
- Switch the "Risk" button to OFF
- Tap the "∑" button to set the Capacity to be equal to the sum of the Energy Offer quantities

We will discuss PLSR% later, but for now we will leave PLSR% switched OFF. After making these changes the Reserves display for gen00 is shown in Figure 141.



bus00_gen00

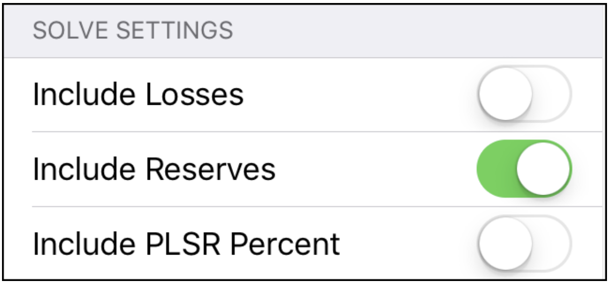
Capacity 60.00 Risk ○

PLSR % 0 PLSR % ○

block1	60.000	MW	2.00	$/MWh
block2	0.000	MW	0.00	$/MWh
block3	0.000	MW	0.00	$/MWh

Figure 141: Reserve display for gen00 after data entry

After making these changes, open the Solve Settings display (by tapping the Solve button). Change the “Include Reserves” setting to ON as shown in Figure 142.



SOLVE SETTINGS

Include Losses ○

Include Reserves ●

Include PLSR Percent ○

Figure 142: Solve option "Include Reserves" selected to ON

Now, <u>before solving</u>, go back to the network model display. It should look like Figure 143. The black scissor symbols indicate generators that have their Risk switch set to YES, i.e., they are the potential risk setters.

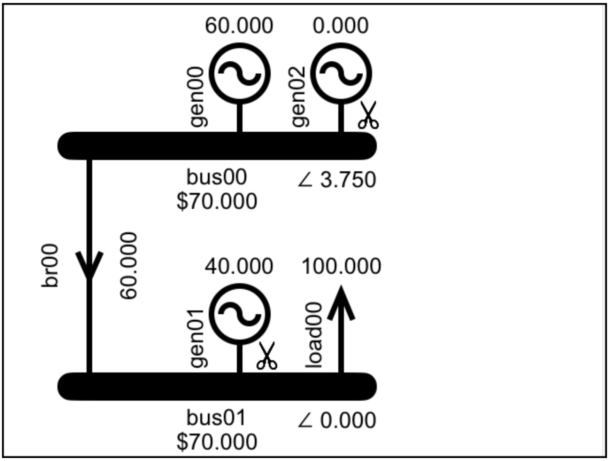


Figure 143: Scissor symbols indicate potential risk setters

Now go back to the Solve menu and tap the "Solve Now" button. In the result, shown in Figure 144, the red scissors indicate potential risk setters that have ended up setting the risk.

Both of the risk setters are presenting a risk of 40MW, which is covered by 40MW of reserve on gen00.

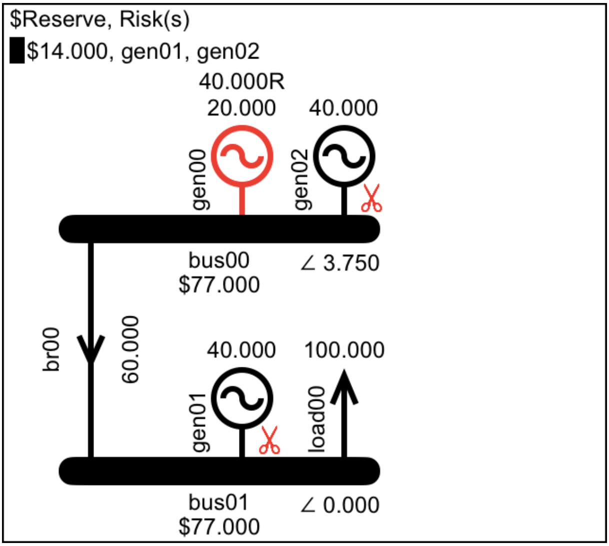


Figure 144: Result with reserve, indicated by R, scheduled on gen00 covering risk presented by gen01 and gen02

Capacity constraint

In the result shown in Figure 144, gen00 is coloured red because it is binding on its capacity constraint. The capacity constraint, shown in Equation 15, enforces the requirement that, when a generator has reserve offers, the total of its scheduled generation and reserve must not exceed the capacity limit of the generator.

$$ClearedEnergy_{Gen} + ClearedReserve_{Gen} \\ \leq Capacity_{Gen}$$

Equation 15: Generator capacity constraint

If the generator does not have any reserve offers then the capacity constraint is not created because it is not required; when there are only energy offers the sum of the energy offers sets the maximum that can be requested from the generator. When there are energy and reserve offers, with no overarching restriction there would be nothing to stop the cleared energy and the cleared reserve from both reaching the capacity of the generator; the capacity constraint forces the solver to decide how to apportion the generator's capacity between cleared energy and cleared reserve.

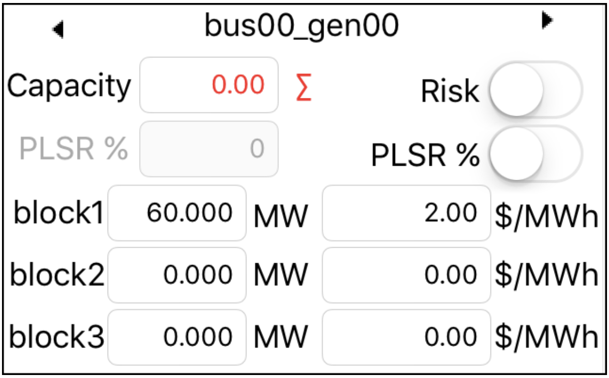
Avoiding a zero capacity constraint

If a generator has reserve offers and the solve has reserve enabled then a capacity of zero would limit the sum of the generator's energy and reserve to zero.

The app could be written so that the capacity limit was always set to be the sum of the energy offers but this would somewhat defeat the purpose of including the capacity limit as an enterable parameter.

Currently the default capacity limit is zero, because until you enter reserve offers, the capacity limit does not apply. Once reserve offers are entered, if there are non-zero reserve offers but the capacity is zero then the capacity field will be highlighted red and the ∑ button will be displayed, as shown in Figure 145.

If the capacity is non-zero but does not match the sum of the offers then the ∑ button will be displayed, but the colour field will be black.



bus00_gen00

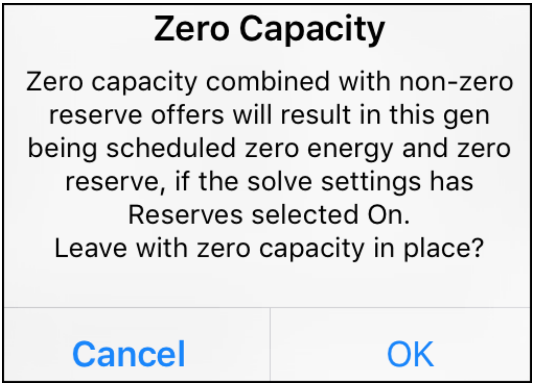
Capacity	0.00	∑	Risk	○	
PLSR %	0		PLSR %	○	
block1	60.000	MW	2.00	$/MWh	
block2	0.000	MW	0.00	$/MWh	
block3	0.000	MW	0.00	$/MWh	

Figure 145: Zero capacity is highlighted red if non-zero reserve offers exist

To set the capacity to be the sum of the energy offers, tap the ∑ button. When the capacity matches the sum of then energy offers then the ∑ button will no longer be displayed.

At some stage you may want to model a situation where the capacity is not equal to the sum of the energy offers, in which case you can manually enter a capacity value.

If you leave the display with non-zero reserve offers in place, but the capacity is still set to zero, then you will be presented with the alert shown in Figure 146.



Zero Capacity

Zero capacity combined with non-zero reserve offers will result in this gen being scheduled zero energy and zero reserve, if the solve settings has Reserves selected On.
Leave with zero capacity in place?

Figure 146: Zero capacity warning

Island largest risk

The largest risk in each electrical island is determined via risk calculation constraints. For now we are only looking at one electrical island, and generator risks, i.e., AC risks. Multiple islands and HVDC risks are covered in Tutorial 7: HVDC Link.

When a model is solved with reserves enabled, each island is assigned a LargestRisk variable and the risk calculation constraint shown in Equation 16 is created for each potential risk setter. The constraint requires that the island's LargestRisk variable be larger than the risk presented by any potential risk setter in the island.

$$ClearedEnergy_{RiskGen} + ClearedReserve_{RiskGen} \leq LargestRiskAC_{Island}$$

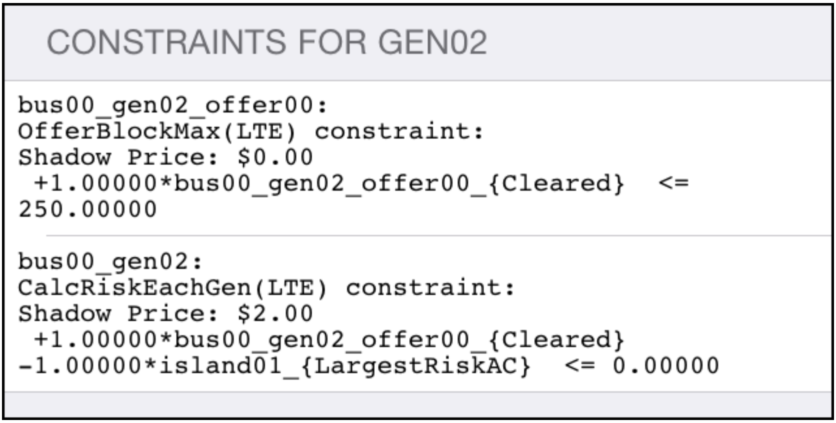
$$\forall RiskGen\ in\ Island$$

Equation 16: Largest Risk Constraint for generators

While it is only the loss of energy that will impact the system frequency, the generator risk calculation includes cleared reserve. This allows the reserve on a risk generator to be used to cover the risk of any other generator, while not covering its own risk.

Viewing the risk constraint

There is a risk calculation associated with every potential risk setter. Figure 147 shows the risk calculation constraint for gen02.



CONSTRAINTS FOR GEN02

```
bus00_gen02_offer00:
OfferBlockMax(LTE) constraint:
Shadow Price: $0.00
 +1.00000*bus00_gen02_offer00_{Cleared}  <=
250.00000

bus00_gen02:
CalcRiskEachGen(LTE) constraint:
Shadow Price: $2.00
 +1.00000*bus00_gen02_offer00_{Cleared}
-1.00000*island01_{LargestRiskAC}  <= 0.00000
```

Figure 147: Constraints for a potential risk setter

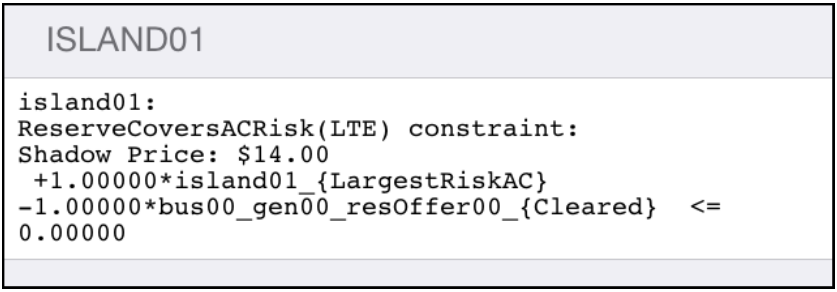
"Reserve covers risk" constraint

Each island has the "reserve covers risk" constraint shown in Equation 17 to ensure that the sum of the cleared reserve offers in the island is sufficient to replace the island's largest risk.

Equation 17: Reserve covers risk constraint

$$\sum_{\substack{Gen \\ in\ Island}} ClearedReserve_{Gen} \geq LargestRiskAC_{Island}$$

The constraints for an island can be viewed via the Constraints option on the Results display, as shown in Figure 148.



```
island01:
ReserveCoversACRisk(LTE) constraint:
Shadow Price: $14.00
 +1.00000*island01_{LargestRiskAC}
-1.00000*bus00_gen00_resOffer00_{Cleared}  <=
0.00000
```

Figure 148: The "reserve covers risk" constraint on the Constraints display

The risk constraints become more interesting when multiple islands are involved, as shown Tutorial 7: HVDC Link.

Reserve offers in the objective function

Cleared reserve offers are included as a cost to the objective value, as shown in Equation 18.

Equation 18: Objective function including reserve offers

Maximize:

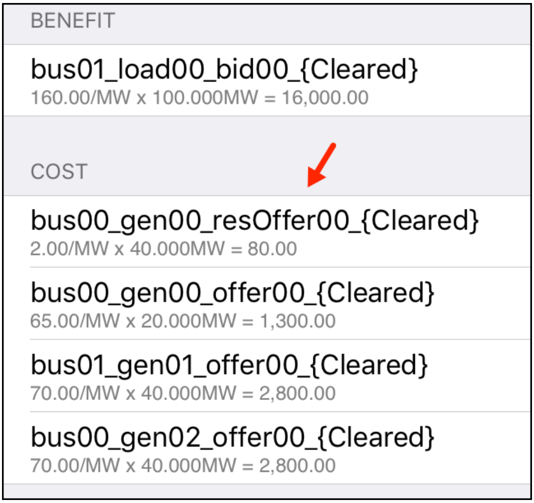
$$ObjectiveValue$$

$$= \ loadBid_{Cleared} \times loadBid_{Price}$$

$$-genOffer_{Cleared} \times genOffer_{Price}$$

$$-reserveOffer_{Cleared} \times reserveOffer_{Price}$$

The objective value calculation for the latest solve can be viewed via the Objective option on the Results display, as shown in Figure 149.



BENEFIT

bus01_load00_bid00_{Cleared}
160.00/MW x 100.000MW = 16,000.00

COST

bus00_gen00_resOffer00_{Cleared}
2.00/MW x 40.000MW = 80.00

bus00_gen00_offer00_{Cleared}
65.00/MW x 20.000MW = 1,300.00

bus01_gen01_offer00_{Cleared}
70.00/MW x 40.000MW = 2,800.00

bus00_gen02_offer00_{Cleared}
70.00/MW x 40.000MW = 2,800.00

Figure 149: Reserve offers in the objective value calculation

Explaining the reserve price

To explain the reserve price in Figure 144 we can use the same mechanism that was used to explain bus prices, i.e., add a $0 quantity and see how it improves the objective value. To this end, add gen03 to bus01 as shown in Figure 150, change its energy offer to be 0MW and add a 1MW reserve offer at $0, with capacity set to 1MW and "Risk" selected to OFF.

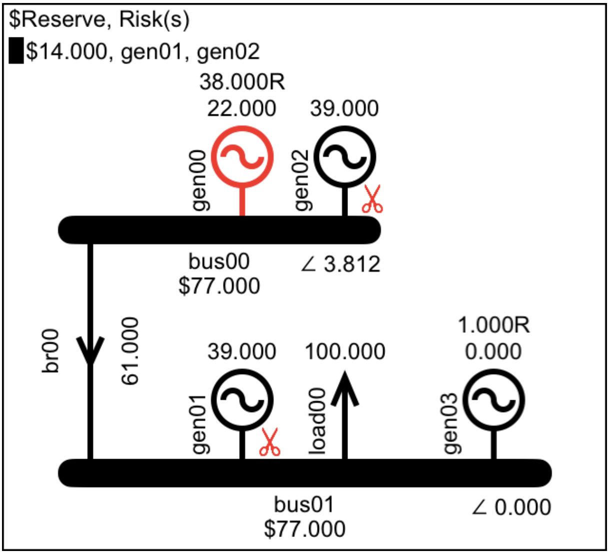


Figure 150: Explain reserve price by adding 1MW of $0 reserve

From the results display we can confirm that adding the $0 reserve has resulted in a $14 improvement in the objective value. From the result in Figure 150 we can explain this $14 improvement as follows…

Because gen00 was binding on its capacity constraint, the extra 1MW of free reserve allowed reserve on gen00 to reduce by 2MW… 1MW because of the 1MW of $0 reserve and 1MW because the risk was reduced by 1MW. The risk was reduced by 1MW because the 2MW decrease in reserve freed up capacity on gen00 allowing for a 2MW increase in the generation, which in turn allowed the generation on the risk setters to reduce by 1MW each. This reduction in risk saves 2MW of scheduled reserve on gen00 at 2 x $2 = $4, and the energy at gen00 is cheaper by $5/MWh than the gen01 and gen02 energy that it replaced, saving 2 x $5, for a total of $14.

Explaining the energy price

We are going to explain the $77/MWh energy price by zeroing the reserves on the dummy generator gen03 and solving to take us back to our original result, then giving gen03 an energy offer of 1MW at $0. The result is shown in Figure 151.

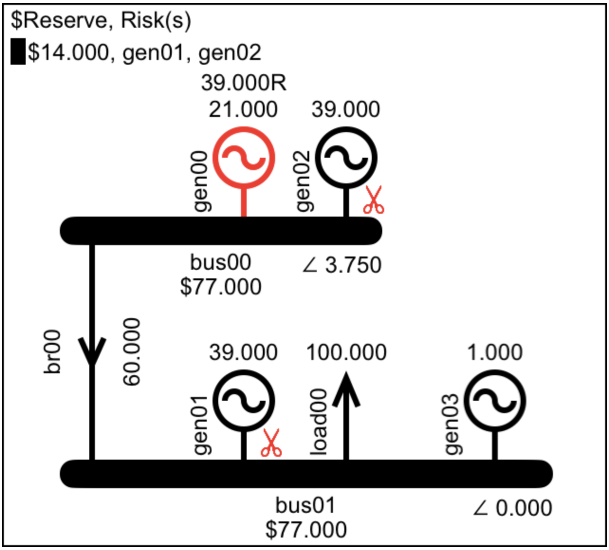


Figure 151: Explain energy price by adding 1MW of $0 gen

The 1MW of $0 energy allows the risk to be reduced by 1MW on both of the risk setters… 1MW of energy from gen01 is replaced by the extra 1MW and 1MW of energy from gen02 is replaced by increasing gen00 generation by 1MW, which is possible within the limits of the capacity constraint because the reserve requirement has decreased by 1MW.

Overall the benefit is due to 1MW less energy from gen01, which saves $70, plus the $2 reserve saving due to 1MW less risk, plus the benefit due to the increased generation at gen00 being $5 cheaper than the energy at gen02 that it replaces, for a total benefit of $77.

Note that because the result that explained the reserve price, i.e., Figure 150, still had the $77/MWh energy price, we could have added the $0 energy and explained the $77/MWh price using that model (i.e., with the $0 reserve offer still in place), but it would be a different explanation because it explains a different result (even though it would explain the same price).

Co-optimisation of energy and reserve

As shown above, adding 1MW of energy or reserve helps to explain the energy and reserve prices. However, without employing this method it would be difficult to intuitively explain the prices due to the interaction between the various trade-offs that are being made when the model is solved.

The process of making the trade-offs between energy, risk, reserve and capacity is referred to as the co-optimisation of energy and reserve.

PLSR% Constraint

The ability of a reserve provider to increase its generation in response to a drop in frequency can be limited by its generation output. For example, a generator that is generating 10MW may not be able to provide another 30MW of generation within the rapid timeframe required when providing reserve. However, if the reserve provider was generating 100MW, then another 30MW may not be a problem.

To model the situations where this limitation will impact on the ability of a generator to effectively provide reserve, the LP model includes the Partly Loaded Spinning Reserve percentage (PLSR%) constraint.

The PLSR acronym refers to reserve (R) that is available when the generator is already generating, i.e., spinning (S), and has spare capacity, i.e., is partly loaded (PL). There are other means of providing reserve (not mentioned here) that do not involve PLSR; the PLSR% constraint only applies to PLSR.

The PLSR% constraint restricts the maximum cleared reserve (specifically PLSR) to a percentage of the cleared energy, as described by Equation 19.

Equation 19: PLSR% constraint

$$ReserveCleared_{Gen} \leq PLSR\%_{Gen} \times EnergyCleared_{Gen}$$

Demonstrating the PLSR% Constraint

Demonstrate the PLSR% constraint by building and solving the model shown in Figure 152, using the default energy offers, and the reserve offers shown in Table 7. Note that you can move between the reserve displays for the various generators by using the navigation buttons highlighted in Figure 153.

	Reserve offer quantity	**Reserve offer price**	**Can Set Risk**	**PLSR%**
gen00	60MW	\$2/MWh	Y	50
gen01	60MW	\$80/MWh	Y	OFF
gen02	0	0	Y	OFF

Table 7: Reserve data for PLSR% example

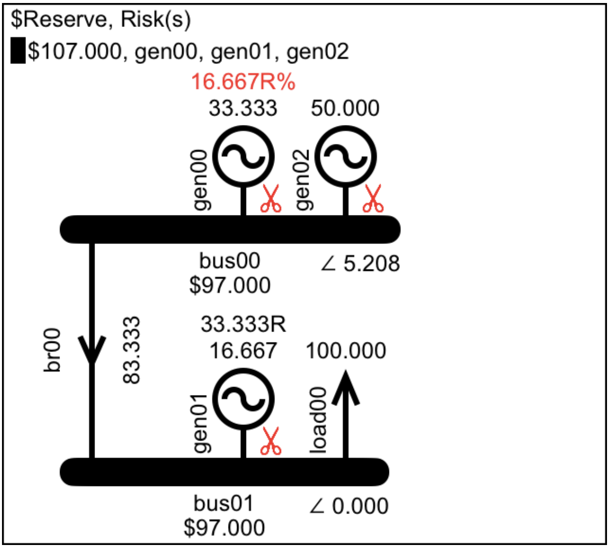
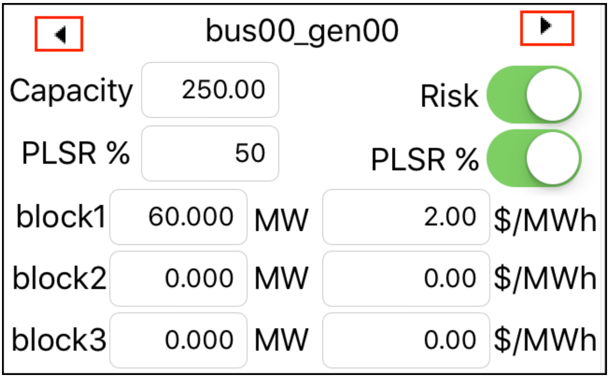


Figure 152: PLSR% constraint applied to gen00

The PLSR% value of 50 is entered by switching on the PLSR% option, as shown in Figure 153, and then entering the value. As per Equation 19 the maximum reserve that can be cleared by gen00 will be capped at 50% of its cleared generation.


bus00_gen00

Capacity 250.00

Risk

PLSR % 50

PLSR %

block1 60.000 MW 2.00 $/MWh

block2 0.000 MW 0.00 $/MWh

block3 0.000 MW 0.00 $/MWh

Figure 153: Switch ON PLSR% to enter a PLSR% value (navigation buttons indicated)

Solve the PLSR example with the solve settings for “Include Reserve” and “Include PLSR%” set to ON.

The result in Figure 152 shows that the solver has wanted to schedule gen00’s cheap reserve but the PLSR% constraint has capped the reserve to 50% of the generation. The reserve quantity for gen00 is displayed in red with a % symbol after it; this indicates that the scheduled reserve is binding on the PLSR% constraint, i.e., the solver would have scheduled more reserve on gen00 if it were not for the PLSR% constraint.

Summary

This tutorial demonstrated how risk and reserve constraints are employed to ensure that generation capacity is available to respond in timely fashion in the event that energy supply (generation) is unexpectedly disconnected from the power system.

We saw how the result balances the requirement to schedule reserve with the limits of generation capacity and the driving objective of minimizing overall cost, by co-optimising the cleared energy and cleared reserve quantities. Co-optimisation makes the resulting prices less intuitive, but they can still be explained by adding a suitably small reserve or generation quantity priced at $0 to demonstrate the value of an incremental MW.

We also explained the PLSR% constraint, which models the relationship between a generator's scheduled energy output and its ability to provide reserve.