SERIS

Solar Energy Research Institute of Singapore

Methodology description:

SERIS future power price scenarios

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1 General

1.1 Background

In absence of a feed-in-tariff or other fixed-price power purchase agreements (PPAs), the financial benefits of a photovoltaic (PV) solar system are dependent on the future electricity price progression. There is a general misconception that future electricity prices should indefinitely rise with inflation or at least will be higher in the future than current price levels. In order to visualise financial return sensitivities, SERIS developed various price scenarios for the Singaporean power market, published in the regularly updated “Solar Economics Handbook” on the National Solar Repository (NSR) website [1]. This document should explain the methodology behind the development of these scenarios.

1.2 Disclaimer

This report represents the professional opinions of the members of the evaluation team. The evaluation team members, the Solar Energy Research Institute of Singapore (SERIS) and the National University of Singapore (NUS), exclude any legal liability for any statement made in the report. In no event shall the evaluation team members, SERIS, and NUS of any tier be liable in contract, tort, strict liability, warranty or otherwise, for any special, incidental or consequential damages, such as, but not limited to, delay, disruption, loss of product, loss of anticipated profits or revenue, loss of use of the equipment or system, non-operation or increased expense of operation of other equipment or systems, cost of capital, or cost of purchase or replacement equipment systems or power.

2 Introduction

The methodology is based on the assumption that Singapore’s wholesale power market will function under a competitive environment, where in general the most cost-efficient marginal generation plant will be the price setter according to the merit order. This analysis does not take into account extreme scenarios such as oil price shocks or massive declines (as seen, for example, following the financial crises in 2008) nor profit maximization strategies by generation companies (gencos). It aims to improve the understanding how certain parameters can influence future electricity prices in the medium to long-term. The scenarios do not take into considerations short-term influences, such as, for example, maintenance schedule, unexpected plant outages and demand changes, the reserve market mechanism etc., hence they are not appropriate to be used for trading activities.

Three types of scenarios were formed, the “most-likely”, the “maximum” and the “minimum”. It is important to understand that each scenario bundles together some “pessimistic” assumptions (i.e. for the minimum scenario) and some “optimistic” assumptions (i.e. for the maximum scenario). This work does not provide any views regarding the likelihood that all the underlying assumptions might indeed happen in a “bundled” fashion nor does it express opinion regarding the probability of each scenario occurring. There are many more scenarios possible, e.g. a high oil price scenario coupled with a low electricity demand environment. Further investigations can be provided on a more “customized” basis. Figure 1 and Figure 2 show how electricity prices have developed historically in Singapore.

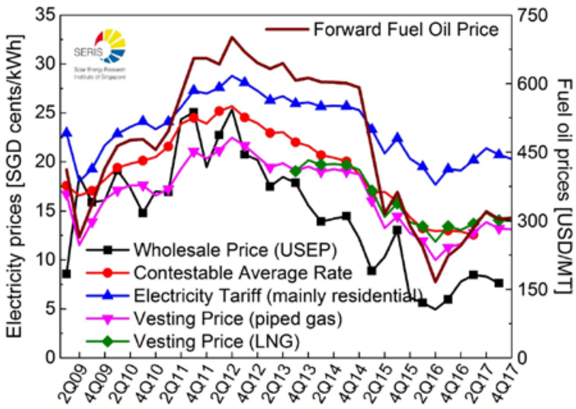

Figure 1: Historic electricity prices in Singapore, data source: EMA, SP Services, EMC, contestable average rate only available until Feb-2017, USEP available until 24th of September 2017

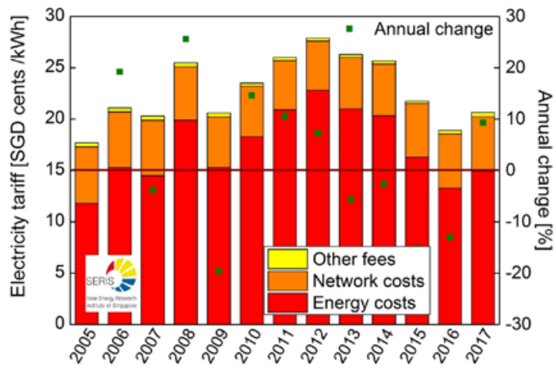

Figure 2: Electricity tariff composition, annual averages, data source: EMA, SP Services, 2017 quarterly: 1Q: 20.2, 2Q: 21.4, 3Q: 20.7, 4Q: 20.3

3 Historic wholesale power price regression analysis

Several independent variables influenced power prices in the past, ranging from changes in the oil price to the reserve margin, the quantity of vesting contracts, the steam plant capacity factor, the progress of liberalisation of end-customers, to name a few. Some of them became less relevant for the future, such as, for example, the steam plant capacity factor, with oil-fuelled steam turbines being almost entirely replaced by higher efficient combined cycle gas turbines (CCGTs). Others such as the quantity of vesting contracts influence end-customer prices even stronger than the Uniform Singapore Energy Price (USEP)[1] itself. Increasing liberalisation might change the hedging behaviour of gencos by lowering the amount of bilateral contracts and expanding their activities in trading directly in the National Electricity Market of Singapore (NEMS). Due to competitive pressure, gencos might even be willing to sell below their own short-run marginal cost (SRMC = fuel and variable operating and maintenance cost) in order to retain customers. This kind of extreme competition can only last for a restricted time period and has not been taken into account in this work. In addition, the share of the contestable clients' demand in percentage of total generated electricity was roughly constant at ~66% during the last ten years and hence is not meaningful to be included in a regression analysis.

It was therefore decided to concentrate on the two main influential factors: 1) fuel price development of the marginal conventional power plant in Singapore and 2) the supply-demand relationship, i.e. the reserve margin[2]. Figure 3 and Figure 4 show the historic relationship between USEP and these two depending variables. The time horizon was chosen from May 2013 onwards, in-line with the commissioning of the LNG terminal. The latter brought a relief to gas constraint issues of current piped gas volumes which were the main reasons USEP was elevated during 2011 and 2012. The reserve margin calculation was adjusted by excluding the ~ 2,720 MW installed oil-fuelled steam turbines. It is assumed that they will play a minor role going forward to produce electricity in Singapore. There is now plenty of gas and

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[1] *USEP = weighted-average of the nodal prices at all off-take nodes in each half hour. It is the uniform price of energy that applies for settlement purposes for all energy injections or withdrawals that are deemed to occur at the Singapore hub.*

[2] *The reserve margin is defined as the excess installed capacity in % of the system peak demand.*

CCGT capacities available and, in addition, the vesting regime, who supported the economics of these power plants lately, will be phased out soon.

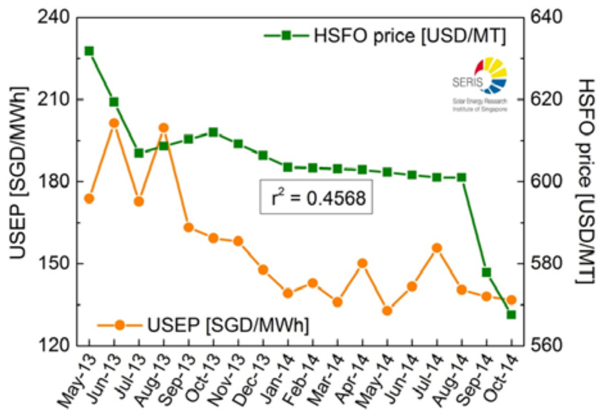

Figure 3: Historic correlation between USEP and HSFO price, HSFO = High-Sulphur Fuel Oil

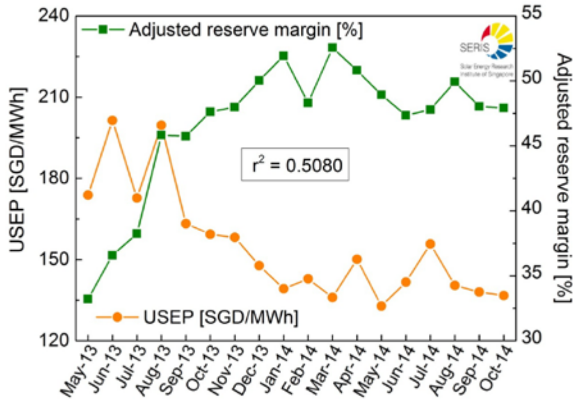

Figure 4: Historic correlation between USEP and reserve margin

The selected time horizon for Figure 3 and Figure 4 ends at October 2014, as from then onwards the major drop in oil prices lead to a significant fall in USEP. Both reached their lows in 1Q2016, a ~65% reduction from their October 2014 levels. During this time period, the adjusted reserve margin remained at elevated levels between 48-50%. The magnitude of the relationship between USEP and the two independent variables changed overtime. We believe that in the time period of May 2013 to October 2014, USEP's decline was caused mainly by the rising overcapacity. In contrast, thereafter, it was predominantly the significant reduction in oil prices which resulted in a further reduction of the USEP. It was therefore decided to only use the historic correlation between the adjusted reserve margin and USEP for the formula. On top of this, the fuel cost changes are then added. In Singapore, LNG-gas is more expensive than pipeline gas, hence it is assumed that the marginal power plant is a LNG-fuelled CCGT. Due to this fact, the model uses the Brent oil forward price instead of the high-sulphur fuel oil (HSFO) price as the benchmark going forward. Until now, all long-term import gas contracts are linked to oil price benchmarks with pipeline contracts pegged to the HSFO price and the LNG contracts linked to Brent oil price. In the medium term future, also with the introduction of the spot gas index at SGX and EMC under "SGX LNG Index Group (SLING)" the terms might be re-negotiated and the oil-price link might be gradually abandoned. This effect has not been investigated and is not yet included in this analysis.

The underlying formula is shown in the following equation (acronyms are explained below):

$$USEP_{fm} = (285 – 279\ (ARM_{fm}))*(1+(CFOPC_{fm})*(FCS_{fm}))$$

The model operates with monthly average USEP values, while the output of the different scenarios are summarised into annual values. The outputs are adjusted regularly to make the figures "up-to-date". For example estimated values for the year 2017 already take into account "real" USEP values until the latest available data point (e.g. for the 3Q2017 Solar Economics Handbook, until September 2017), with the monthly values of October to December added based on the formula above. The term "FM" refers to a particular month in the future, where the regression formula was applied with regards to the estimated adjusted reserve margin (ARM) for this particular month. The cumulative forward oil price change (CFOPC) compared to the reference month (October 2014) is then added. This relationship is thought to be linear and added in full if the market remains in an overcapacity situation (defined as ARM > 35%). The reason being that in overcapacity situations, the USEP should reflect SRMC, which contain mainly fuel cost. If the ARM goes below 35%, the market will become more balanced and USEP should start to reflect the long-run marginal cost (LRMC) of a new CCGT, hence the change of the oil price will only be added according to the estimated fuel cost share (FCS). The main underlying input parameters for this formula are discussed in the following sections.

4 Oil price scenarios

Oil price scenarios are built upon the available forward price curve for Brent oil prices (see Figure 5). For the 3Q2017 Solar Economics Handbook the 29-September-2017 forward curve have been chosen. As the forward pricing is only available until 2024, a flat development has been assumed thereafter. While the most-likely scenario is based on the available market curve, the minimum and the maximum scenarios are -25% and +25% of this curve, respectively. In all three scenarios a flat development after 2024 at the prevailing level is assumed (see Figure 6).

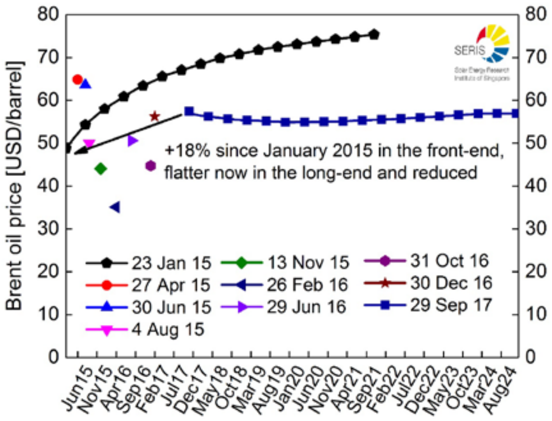

Figure 5: Latest forward price curve for Brent oil prices, data source: CME Group, Brent crude oil futures settlements

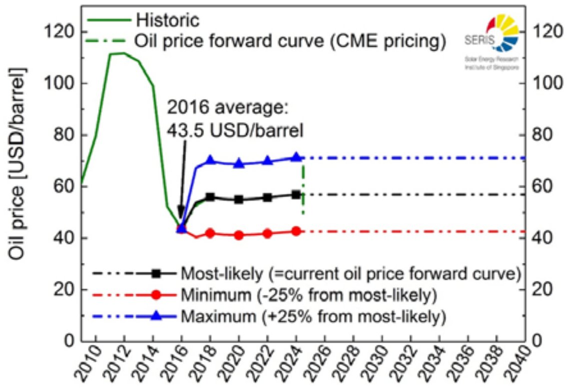

Figure 6: Future oil price scenarios as per 29-Sep-2017, Brent forward price curve until 2024, +25%/-25% for the maximum and minimum scenario, respectively, flat growth assumption thereafter

5 Adjusted reserve margin scenarios

The estimation of the adjusted reserve margin is based on three input parameters: i) possible changes of the installed conventional capacity in the future, ii) the annual growth expectations of system peak demand and iii) peak shaving estimation from newly added solar capacity.

Regarding the future development of installed capacity, historical generation capacity is based on EMC data (see Figure 7) and capacity additions announced in the annual report “Singapore Energy Market Outlook” (SEMO) from the Energy Market Authority (EMA) [2] and other industry inputs if any. The 3Q2017 Solar Economic Handbook was still based on SEMO 2016, which expected an addition of 300 MW of embedded generation in 2017. The 4Q2017 Solar Economics Handbook will be updated with the recently published SEMO 2017, which estimates an installed capacity of ~13,500 MW by end of 2017. Any potential retirements of old oil-fired steam turbines do not affect the scenarios, as they are already excluded from the reserve margin considerations in this work. In addition, based on the government’s minimum reserve margin of 30%, the model adds new CCGT capacity as soon as the adjusted reserve margin drops below 30% (for the most-likely scenario) and below 25% (for the maximum scenario). Regional transmission constraints are not taken into account. So far any retirement without replacement of the current CCGT fleet is not taken into consideration.

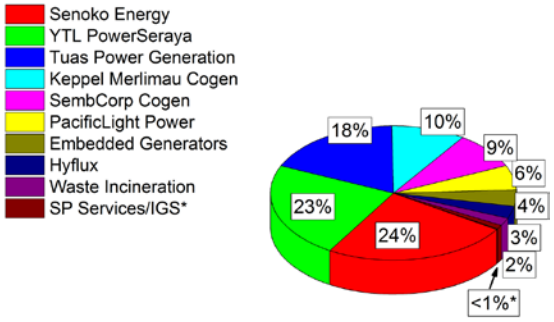

Figure 7: Installed capacity as of 21-Sep-2017, 13,482 MW, *SP Services and IGS owners have started to register PV systems who chose EMC registration, IGS = Intermittent Generation Sources, data source: EMC

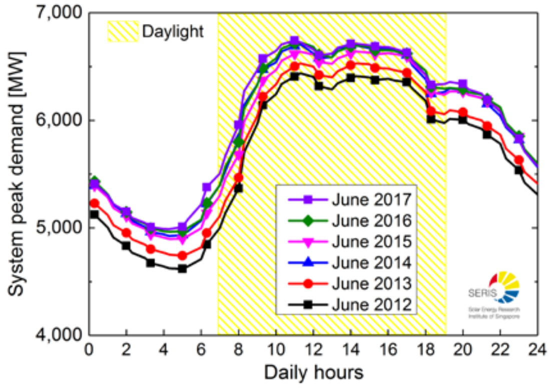

Figure 8: Historic average daily system peak demand profile, excluding weekends/public holidays, data source: EMA

As solar PV generation is variable and non-dispatchable, it is not taken into account in the installed capacity calculation mentioned above. However it is taken into account within the peak demand estimation, as in Singapore, especially on working days, the system peak demand occurs during sunshine hours (see Figure 8). Due to temperature losses, especially occurring on hot sunny days, and other uncertainties, only 50% of the expected installed PV capacity is assumed to “shave” the peak system demand. The expected installed PV capacity follows the Solar PV Roadmap [3], published in 2014 following the baseline scenario (see Figure 9) expecting 650 MW_p, 3 GW_p and 5 GW_p by 2020, 2030 and 2050, respectively. While the minimum scenario expects 100% achievement of this baseline scenario, the most-likely and maximum scenario expect 75% and 50%, respectively.

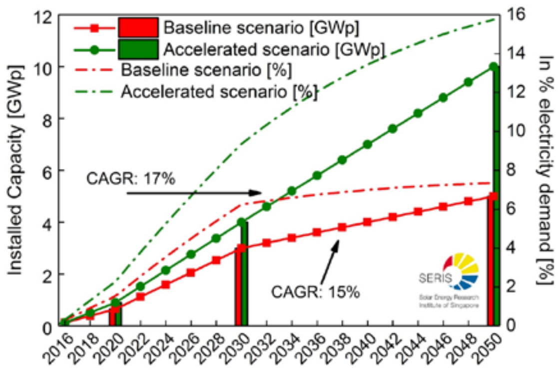

Figure 9: Future solar PV potential in Singapore according to the Solar PV Roadmap, annual electricity demand growth assumed for this specific graph: 2%

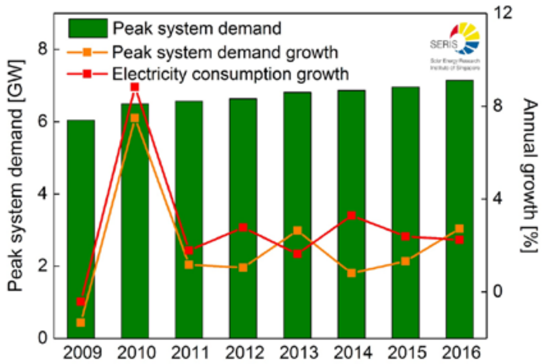

Figure 10: Historic peak system demand, +2.7% in 2016 compared to 2015, electricity consumption +2.2%, data source: EMA

Peak system demand has grown on average 2.5% p.a. from 2009 to 2016, 1.7% p.a. over the last five years, excluding 2009 and 2010, which were rather untypical years due to the financial crises situation (see Figure 10). The relationship between GDP and electricity demand growth in Singapore varies within the last ten years as can be seen in Figure 11. While GDP growth during 2013 was almost double the electricity demand growth, there were other years where electricity demand surpassed GDP growth. Based on the last ten years dataset, in general it can be concluded that in years where economic growth was weak (i.e. 2009, 2012) due to its demand inelasticity, electricity consumption growth surpassed GDP growth. In contrast, when GDP growth is strong, electricity demand growth is lower (i.e. 2010, 2011). In the last three years, the electricity demand growth was very much aligned with GDP growth. However, electricity demand growth might vary from the peak system demand development, highlighted in Figure 10. Important for the reserve margin calculation is the peak system demand pattern and not the annual demand growth. However, without significant time-of-use pricing in Singapore and the absence of other strong incentives to save during peak hours, it is assumed that the peak system demand will grow similarly to electricity demand growth. Currently the Ministry of Trade and Industry (MTI) expects GDP growth of 3.0 to 3.5% in 2017, 1.5 to 3.5% in 2018 [4].

For this work, peak system demand growth rates of 1%, 2% and 3% were assumed for the minimum, most-likely and maximum scenarios (not yet including the reductions from solar addition, as explained before). So far it is expected that peak demand will grow indefinitely at these rates. This might not happen in case more stringent climate change policies are enacted (such as the announced carbon tax). After including the peak-shaving assumptions from solar, the “net” average demand growth annually is assumed to be (until 2030) -0.4%, 1.1% and 2.5% for the minimum, most-likely and maximum scenarios, respectively.

Combining all these underlying assumptions, the adjusted reserve margin scenarios are visualised in Figure 12. In the minimum scenario, overcapacity would remain and no additional conventional power capacities are needed with the exception of the embedded generation added in year 2017. In the most-likely scenario, new F-class CCGT of one unit each (408 MW [5]) will be added every second year from 2032 onwards. This is needed to ensure that the adjusted reserve margin remains within the 30% minimum requirement. Regarding the maximum scenario, two units are added in 2026 and 2029, and then again every second year from 2032 onwards in orader to keep the adjusted reserve margin at around 25% adjusted reserve margin.

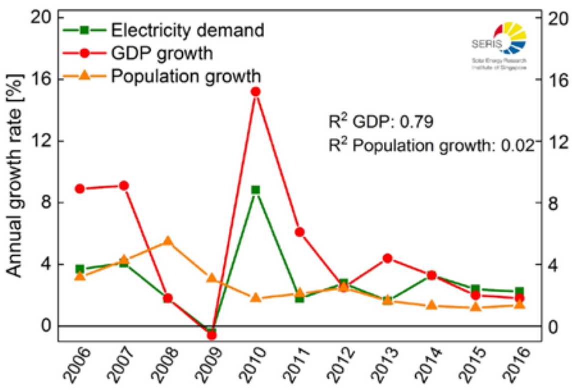

Figure 11: Electricity demand drivers, data source: EMA, Singapore Department of Statistics, Ministry of Trade and Industry (MTI)

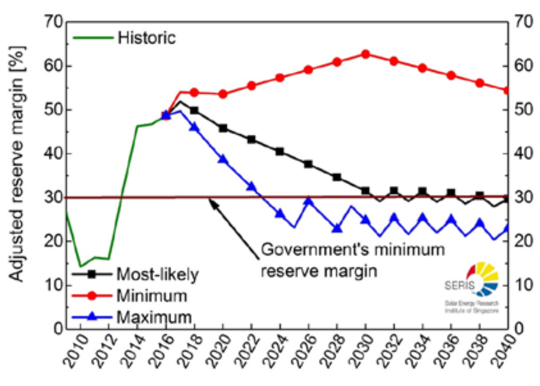

Figure 12: Adjusted reserve margin scenarios, future CCGT added as soon as reserve margin < 30% (<25% for the maximum scenario)

Table 1 provides a summary of the key assumptions for calculating the adjusted reserve margin scenarios over a time horizon from 2017 to 2042. The outcome is highly sensitive to the demand growth assumption and at which point in time new capacity will be added. The addition of bulky new gas power plants causes the spikes in the energy prices. Under the minimum scenario, the adjusted reserve margin gradually increases, reaching its peak in 2030 before declining thereafter. The reason for this is that annual additions of PV capacity need to be ~235 MW_p to reach 3 GW_p by 2030 (according to the baseline scenario in the PV Solar Roadmap, see Figure 9). After 2030, annual additions of solar decline to ~100 MW_p to meet ~4 GW_p by 2040, hence during this period, annual demand growth will outweigh peak-shavings from solar, reducing the reserve margin from then onwards.

Table 1: Underlying assumptions for calculating the reserve margin (2017 – 2040)

Scenarios	Annual system peak demand growth (%)	PV Solar Capacity installed by 2040 (MW_p)	Conventional Capacity addition 2017-2040 (MW)
Minimum	1%	4,200	300
Most-likely	2%	3,150	2,748
Maximum	3%	2,100	6,827

6 USEP scenarios

Based on these oil price and the adjusted reserve margin assumptions, Figure 13 shows the three future price scenarios for the USEP. It can be observed that the most-likely scenario roughly follows the current SGX USEP futures price curve which is added as a dotted green line. To test whether these outcomes are realistic, the progression of the SRMC and LRMC of a new entrant CCGT is added (see Figure 14 to Figure 16).

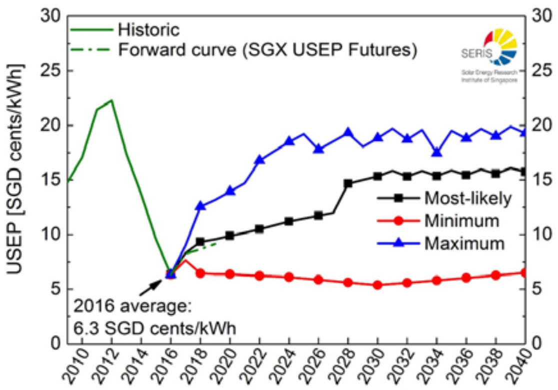

Figure 13: Future wholesale power price scenarios (i.e. USEP) based on the 29-Sep-2017 Brent oil forward price curve.

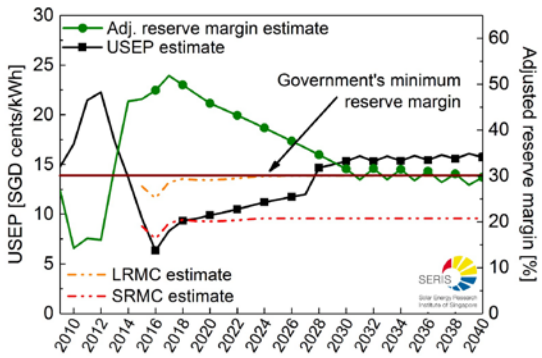

Figure 14: Most-likely USEP and reserve margin future scenarios compared to prevailing SRMC/LRMC future assumptions.

In a competitive wholesale power market, the price should reflect the SRMC of the marginal power producer in case of an oversupply situation. In contrast, in case of a tight market environment, the price should reflect or even exceed the LRMC in order to incentivise new investments. Future scenarios of the SRMC and the LRMC of a new CCGT in Singapore are based on EMA's methodology to determine the vesting contract prices [6]. The current values use the basis determined in the 2017-2018 review, with annual fixed cost and the variable non-fuel cost at 40.8 SGD/MWh and 7.5 SGD/MWh, respectively. Both are adjusted by a small cost inflation amount of 0.5% per annum until 2026, flat thereafter. The fuel component is then adjusted by the different future oil price scenarios.

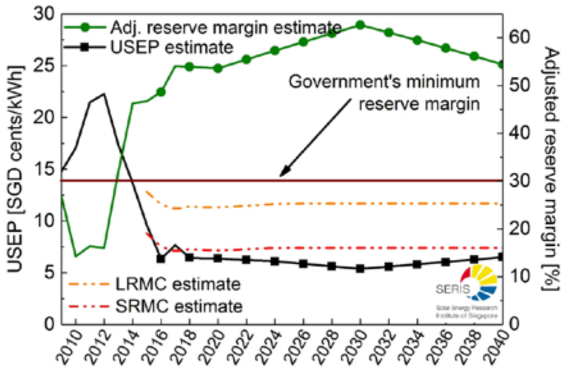

Figure 15: Minimum USEP and reserve margin future scenarios compared to prevailing SRMC/LRMC future assumptions.

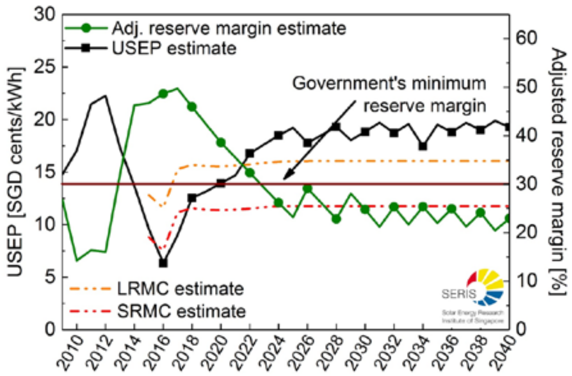

Figure 16: Maximum USEP and reserve margin future scenarios compared to prevailing SRMC/LRMC future assumptions.

It is illustrated that in the most-likely scenario (see Figure 14), in-line with the gradual reduction of the overcapacity, USEP will recover and surpass estimated LRMC when adjusted reserve margin is getting closer to the 30% minimum requirement. This will be just in-time to incentivize new investments. A faster recovery trend is happening in the maximum scenario (see Figure 16) where the minimum reserve margin is already reached in year 2023. Due to a more aggressive assumption, that power station will only be installed when the reserve margin goes below 25%, USEP prices remain elevated, slightly above the LRMC estimates. In contrast, no recovery does occur under the minimum scenario (see Figure 15) where USEP will remain depressed, even at a slightly lower level than the LNG-fuelled SRMC estimates.

These USEP future scenarios build now the basis for the estimations of end-user electricity prices.

7 Electricity tariff scenarios

Figure 2 illustrates the different parts of the historic electricity tariffs. The energy cost is fully reflective of the vesting prices, the LRMC of new gas-fired power plants in Singapore, regulated by EMA. These are currently significantly higher than wholesale power prices, reflecting the overcapacity situation. Figure 17 illustrates the historic development of the vesting contract quantities compared to the quarterly demand.

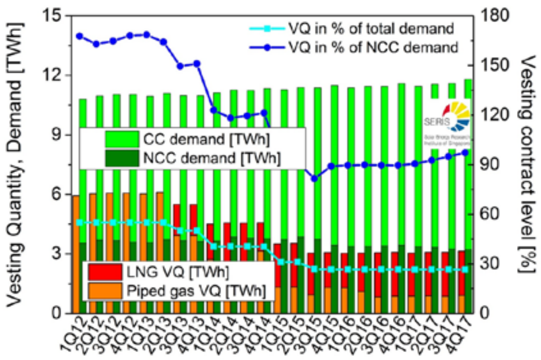

Figure 17: Historic quarterly vesting quantities, if < non-contestable demand, contestable clients need also to pay for the support of the regime

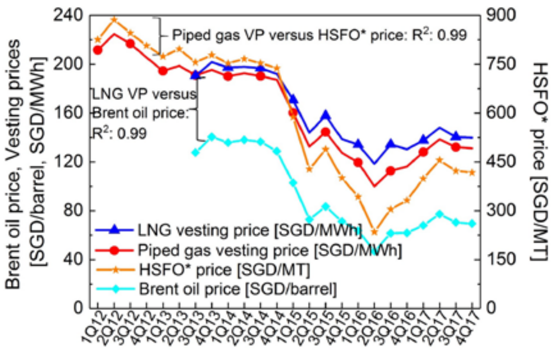

Figure 18: Historic quarterly vesting prices, high correlation with underlying fuel price benchmark, data source: SP Services

While the original vesting regime, which was mandatory for vested installed capacity prior the initiation of the regime (i.e. 1 January 2004) will be phased out by July 2019 [7] the vesting regime supporting LNG-fuelled CCGT will remain until June 2023. The latter comprises ~18-19% of total demand and entitled power plants are remunerated at the regulated LNG vesting price with the historic development shown in Figure 1 and Figure 18.

The cost of this regime (~430 SGD million per quarter in 2017) is first passed-through to the non-contestable clients, with contestable clients required to pay only if there is any left-over. Under the regulated tariff, for non-contestable clients, the wholesale power price is therefore of less significance, unless the vesting quantity drops below the non-contestable clients' demand level and SP Services can source by other means (e.g. by buying outright at USEP or by tendering out its excess power needs above the vesting quantities). This happened since 1Q2015 where the vesting quantities were lower than the non-contestable load, hence on average SP Services bought power in the market for ~10% of its total needs.

Due to the expected full retail liberalisation during the 2nd half of 2018, it is assumed for this work that the non-contestable demand will sharply decline by ~17% (2018), ~40% (2019), ~16% (2020) and ~3% (2021) during the next four years. Under this assumption, after a period of four years, 42% of the original non-contestable demand (4Q2017 as a basis) will remain with SP Services at the regulated tariff and the rest will have become contestable. Due to this effect, it is assumed that the excess load above the vesting quantities will be eliminated during 2018. Hence the energy cost of the electricity tariff will therefore fully reflect the LRMC scenarios including an addition of ~1.7 SGD-cents/kWh (historical difference observed between the energy cost of the electricity tariff and the vesting price). The implication for contestable clients, who need to bear the rest of the vesting regime cost is discussed in the next section.

The current grid fee of 5.3 SGD-cents/kWh is expected to increase at 0.5% per annum and t remain flat from 2026 onwards. The other fees of ~0.42 SGD-cents/kWh are expected to remain stable. Figure 19 illustrates the scenarios for the electricity tariff. The decline in 2023 is due to the expected re-pricing once the LNG vesting regime is phased out, especially when the market has not reached market equilibrium (i.e. under the minimum and most-likely scenario). Under these conditions SP Services is expected to re-negotiate better power sourcing deals.

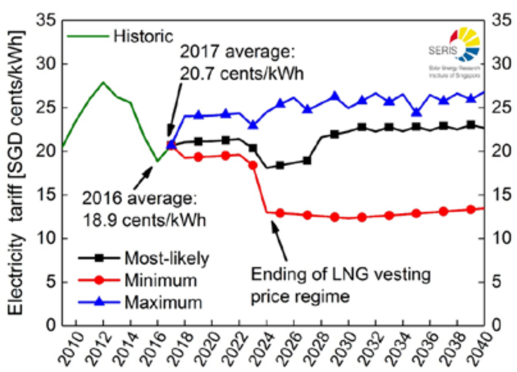

Figure 19: Future average electricity tariff scenarios based on the 29-Sep-2017 Brent oil forward price curve, assuming link to LNG vesting price supports the tariff until July 2023.

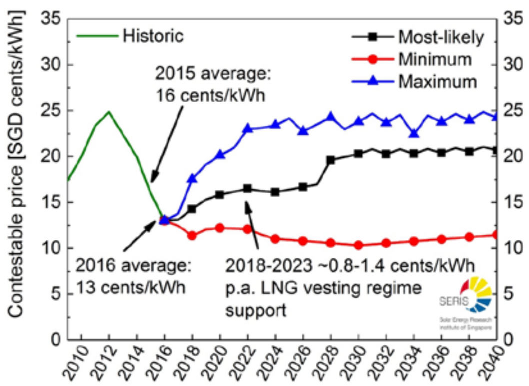

Figure 20: Future average contestable power price scenarios based on the 29-Sep-2017 Brent oil forward price curve, assuming that the energy portion is linked to USEP scenarios

8 Average contestable client power price scenarios

As retailers sell various products to contestable clients, future electricity price scenarios should be based on individual contracts. This would also allow to take into account the point in time where the contract is up for renewal. Besides contract terms, the pricing conditions of contestable client contracts can also differ, either they can be fixed or floating (e.g. pegged directly to the HSFO or Brent oil price index). For this work, a highly generalised average price assumption was used. Historic average values have been derived from EMA's data on volume and revenue figures by retailers for contestable clients [8].

Going forward, for the average contestable client the general assumption was made that the energy cost component should mirror the USEP scenarios as illustrated in Figure 13. This is quite a simplification as in reality retailers tend rather to price products in the range of SRMC plus margin. However, in the current overcapacity situation, the assumption is that USEP builds the floor for the energy component pricing. On top of the USEP, different fees are added with ~1.2 SGD-cents/kWh in total, comprising the difference between wholesale power prices (WEP[3]) and USEP and other Market Support Services (MSS) and Power System Operator (PSO) fees. The grid charge varies among contestable clients not only with consumption (i.e. use of system charge, smaller part of the overall grid charge), but as well with usage of peak capacity (contracted and un-contracted capacity charges, bigger part of the overall grid charge). It was assumed that the average grid charge is ~3.5 SGD-cents/kWh, inflated by 0.5% per annum until 2026, and flat thereafter.

Due to ongoing liberalisation, as discussed under the electricity tariff section, it is assumed that contestable clients will need to also support the LNG vesting price regime until 2023. Hence these additional fees are added from 2018 onwards (~0.8-1.4 SGD-cents/kWh on average per annum ranging from 2018 to 2023) helping to boost prices slightly during this period. In reality this might not happen in a highly competitive market, when retailers might decide not to pass-through this additional cost to end-consumers. Figure 20 illustrates the different scenarios for the future average contestable client price.

9 Limitations

There are many other factors which can influence power prices in the future which are not taken into consideration, for examples:

i) drastic change in regulation, e.g. mandatory energy efficiency targets, high carbon tax (would need to be higher than currently proposed SGD 10-20 per ton to really be a game changer)
ii) intense competition driving down USEP below SRMC
iii) bankruptcy of a main gencos leading to a halt of CCGT production and hence will tighten the market quicker than anticipated
iv) enabled import/export exchange with Malaysia (so far interconnection is only used for daily balancing activities)
v) faster adoption of the ASEAN Power Grid (APG), with Singapore agreeing to import a large amount of renewables from other Southeast Asian countries

[3] *The WEP is the net purchase price paid by retailers, it is the USEP including various fees to cover the administrative costs incurred in the wholesale market.*

vi) extreme development of oil prices, and/or a faster de-link of gas purchase terms from oil prices, with contracts being based on spot gas prices

In addition, the formula is based on the historic relationship between USEP and the reserve margin, which might not repeat itself in the same magnitude in the future. It is also noteworthy that each scenario represents a combination of assumptions. For example in the minimum scenario, not only a pessimistic oil price has been taken into account, but as well coupled with low demand growth and a high adoption of solar PV (which should enable peak-shaving, and hence represents a “negative” demand, increasing the reserve margin). There are many more possibilities how underlying parameters might be combined to different scenarios. In addition, the “minimum” scenario does not reflect a “worst-case” scenario (e.g. in the event of drastically dropping oil prices).

10 Conclusion

While this analysis simplifies some assumptions regarding future power prices it can help to understand the sensitivities of returns of solar PV installations in Singapore towards future power price developments. The model is continuously adjusted not only taking into account latest oil prices, but also changes in the regulatory framework and the overall industry, with all underlying assumptions being updated regularly.

11 References

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