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Electricity Supply, Demand and Prices in Myanmar – How to Close the Gap?

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Background

Myanmar has much less electricity per person than most Asian nations and also has a lower share of households getting grid power than its neighbors. This is beginning to change, as the share of households and the supply of electricity have begun to rise in recent years.[1] However, there is a huge deficit between current demand and available supply. Supply in 2012 would have had to increase by 50% to equal 2012 demand and the quality of electricity is not good. Blackouts and voltage fluctuations are common. This lack of power, except from high-priced diesel, creates higher costs and holds back economic growth. It also inconveniences 70% of Myanmar people who lack access to grid power and is a source of regional inequality greatly limiting wider economic development in most states and divisions.

Sources and Costs

Most electricity in Myanmar comes from hydroelectric sources – roughly 3000 megawatts out of 4200 MW in total capacity. Hydro sources can provide electricity at their rated capacity for roughly half of the year. In the dry season (3-4 months), the system can provide only 30-40% of full potential capacity due to a lack of water and limited reservoir size. The remaining time the system provides 2/3 to ¾ of full capacity. The old hydroelectric stations have very low costs and these costs underpin the basis of the very low 35 to 50 kyat per kilowatt-hour price paid by consumers, even after the recent price increases.[2] According to the Ministry of Electric Power, new hydroelectricity requires 60-70 kyat for a delivered price to cover its costs.[3] Gas electricity, accounting for less than a quarter of total generation capacity, would now have to charge 120-130 kyat/kWh to cover the cost of production and distribution. (This assumes natural gas costing $11 to $12 per million BTU.) However, these costs are in line with current costs in other Asian nations and do not reflect inefficiency. If the public or policy makers want to pay less than the cost of new power, there will not be much commercial interest or ability in producing additional supplies. Nor will friendly donor countries or organizations support many new projects selling below-cost electricity.

There is a big medium-term problem with electricity supply in Myanmar. There will be only modest additions to hydroelectric capacity in the period from 2014 to 2019 and very little net new natural gas for domestic use will come on line. Some new gas will become available from the Chinese Shwe Gas pipeline and other development, but substantial new gas supplies will only become available for domestic use in 2019-20. Meanwhile, some hydro that is now exported may be switched to domestic

[1] Total sales rose from 7717 million kWh in 2011-12 to 9629 million kWh in 2013-14, a rise of nearly 25% in two years. However, that still gives Myanmar only 189 kWh per capita compared to 229 kWh pc for Bangladesh and more than 1200 kWh per capita for Vietnam. It is unlikely that supply will continue to grow so fast in the next several years unless higher priced fuels are used.

[2] Recent price changes to non-residential electricity can raise price as high as 75-150 kyat per kWh. In Vietnam, a nation with similar reliance on hydroelectricity in the north and gas in the south, residential electricity prices in 2015 will range from seven to nine cents per kWh, two to three times as high as Myanmar's new household prices.

[3] Higher costs have been estimated by other sources.

use and some old gas-fired units will get more efficient new equipment and so be able to produce more electricity from the same amount of gas. However, these additions will fall far short of new demand growth during 2014-2019.[4] The more than 1400 MW of new gas units officially projected to be coming on line in 2015-16 will be forced to use, in part, LPG or even expensive liquid fuels if the official reports of limited additional supplies of natural gas for domestic use are correct. If world wholesale diesel or kerosene prices continue at their recently lower levels, the cost of electricity would be higher than current prices charged but much less than diesel electricity has cost in the past – over 400 kyat per kWh. Indeed, LPG-fired power in efficient generators could cover costs at current industrial power prices of K130 to K150 per kWh. (See Appendix 3 for discussion of electricity costs and fuel costs.)

There is some debate about demand growth, but one estimate (2012 ADB[5]) was that demand in 2012 was 12.5 million kilowatt-hours, while supply available for consumption in that year was only 8.3 million kWh.[6] In addition, a growing economy at this low development stage has a high growth of electricity relative to real output growth. In Indonesia and Vietnam, electricity use per capita grew 2-3 times faster than real GDP growth per capita and a 15% growth in underlying electricity demand is probably consistent with 7-8% GDP growth. (See Appendix 2 for their experiences.) The ADB growth cited as coming from the Ministry of Electric Power was 12.8% a year for electricity consumption. So, even if supplies doubled every five to six years – it would still not fully allow for closing the gap between demand and available supply that existed in 2012 or for increasing the coverage of households with grid connected power. Increasing thermal capacity to balance the dry season hydroelectric shortfalls would help to reduce blackouts. That is desirable but difficult since little new natural gas is available (apart from LPG) and coal plants take 5-6 years to build. If supplies grow more slowly than demand, there will be increased blackouts and reliance on expensive liquid fuels such as diesel, costing at least 400 kyat per kWh in 2013. This is expensive and slows growth. (Current diesel prices are lower, as discussed in Appendix 3.)

Aside from the limited new generation coming on-line and some diversion of exported electricity to domestic use, there is the possibility of negotiating with China to import electricity through Kachin state. This would require a strengthening and extension of the national grid, but this could be done in 1-2 years and could provide the Mandalay-Sagaing-Magway-Shan areas with more power. Extending this new supply to the Yangon area, currently the heaviest source of demand, would be expensive and would take more time. The transmission lines from the proposed dams above Myitsone will have to be built in

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[4] Most coal plants and medium-large hydro takes 5-7 years to complete construction, so unless they are already underway, they will not provide much supply up to 2019. Gas plants can be put in place much more quickly, but have to use more expensive diesel/kerosene or propane/LPG if natural gas is not available.

[5] Myanmar Initial Energy Sector Assessment, Asian Development Bank, October 2012, pages 28 and 58. A Project Appraisal Document from the World Bank (PAD 586, August 2013) has a similar projected growth rate on p. 78.

[6] The gross generation in 2012/13 was nearly 11 billion kWh but losses amounted to 2.7 billion kWh. While some of this is due to the old and inefficient transmission and distribution system which badly needs upgrading, some observers argue that at least half of the "losses" represent electricity used but not paid for by favored groups. A normal rate of losses is a third to two-fifths of the current loss rate.

any case, so moving them forward in time would not be a waste, since once the dams were built they could carry domestic hydropower to both the northern grid in Myanmar and to China.[7]

The construction of Chinese-financed dams in Kachin state, negotiated by the previous government, has slowed after the suspension of work on Myitsone, the largest of the proposed dams. There has been popular opposition to that particular dam (Myitsone) and it may or may not go ahead depending on the policy adopted after 2015 elections. However, the larger point is that the contractual terms for all of these Kachin dams are poor from Myanmar's point of view. While some of the power produced at these projects could be purchased above the 10% given "for free" to Myanmar (in return for providing the site), most of the power will go to China. If electricity is worth seven cents per kWh, then only 0.7 cents per kWh (provided as in-kind electricity) of total kilowatt-hours produced go to Myanmar. (Minor amounts of other taxes or payments are possible but will not likely amount to much.) In Laos, the return was more like two cents in cash or kind to the country per kWh produced. It would be cheaper for Myanmar to proceed more slowly and build these projects on its own with loans from external lenders if renegotiations cannot provide more beneficial terms for Myanmar, similar to those in Laos. Alternatively, the contracts could be reopened and other foreign bidders could compete. In any case, the production of these dams will not start until after 2020 since they take so long to build.

The following pages suggest short to medium and longer terms steps to accelerate the economic availability of electricity within Myanmar.

Short to Medium Term Steps

In the years from 2014-2018, there are limited options:

1. ***Take advantage of agreements to buy electricity from hydroelectric projects that are now exporting to China***. These agreements often allow some of the power to be diverted to domestic use if it is paid for and if the export customer agrees. This is done now with Shweli-1.

2. ***To the extent possible, buy a portion of currently exported natural gas for domestic use***. Most gas export contracts allow some small portion of the exported gas to be used domestically, and even more at the discretion of the export customer. However, Thailand currently gets a penalty payment from Myanmar because it does not supply as much gas as contracted, so this source is not likely to be large and in any case would be intermittent. One does not build new capacity based on uncertain and occasional gas supplies. When renewal of Thai gas export contracts comes up, allowing for more domestic diversion is also a possibility.

[7] There are 8300 megawatts of capacity in five dams upstream of Myitsone and not including Myitsone. The most advanced is Chibwe (2000 MW) but Pashe (1600 MW), Lakin (1500 MW), Phizaw (1500 MW), and Khaunglanphu (1700 MW) are all feasible sites. They will need transmission lines to China and further south in any case.

3. ***Hasten the completion of existing hydro projects*** now under construction including the Shwe Li-3 project (1050MW), which appears to be a sound project that could increase national capacity by a significant amount within the next 5 to 6 years.

4. ***Use LPG (propane) as a transition fuel for gas generators*** until additional natural gas is available. These generators can use either fuel and be put in place quickly. The propane is half the cost of diesel electricity but still a third or so more expensive than natural gas at today's prices. If industrial users want reliable power at all times, they could agree to pay the higher cost of propane-fueled power. If oil prices continue to fall and were reflected in local fuel prices, even kerosene would become an option for use in combined cycle generators.

5. ***Work on energy efficiency and reduced transmission/distribution losses***.

6. ***Promote off-grid or mini-grid renewable supplies*** such as solar, wind, biofuels generators or mini-hydro. These can provide modest household supplies to rural households and a backup supply to town users.

7. ***Larger scale, grid connected solar projects***, possible in the Dry Zone with its strong solar resource, offer fairly rapid roll-out possibilities (6 to 12 months construction period for 50MW scale plants), predictable day-peak power generation and a complement to dry season (low water) hydro-electric challenges. However, efficient use of grid-connected solar requires careful execution of systemic load balancing and grid management to maximize benefits and generation costs are likely to be 140 to 150 kyat per kWh, even with modest interest charges on loans for the solar investments. However, this is still much less than current diesel power. Solar can also lock in production pricing for 20 to 25 years, as there is no variable future cost as with carbon-based fuels.

8. ***Investigate the possibility of rapid extension of transmission lines from Mandalay to China to buy electricity supplies from China*** if these are available for sale. Vietnam buys Chinese electricity at 60-70 kyat/kWh equivalent price. Current grid transmission connections are weak from Kachin to the central grid and nonexistent from Kachin to Yunnan, though the distance to extend the grid is less than 100 km.

9. ***Renegotiate existing Chinese hydroelectric contracts*** to reflect equitable terms or proceed with large-scale hydroelectricity with other foreign or domestic funding.

Longer Term Steps

In the years 2019-2023:

1. ***Switch interim LPG or kerosene to natural gas*** as natural gas becomes available.

2. ***Bring new coal plants online*** if they meet environmental standards.

3. ***Bring new natural gas generators online*** if domestic gas supplies are adequate, likely if significant new commercial discoveries are made in deep sea blocks set to be explored over the next 3 to 5 years.

4. ***Extend and strengthen the transmission lines*** to bring increased hydroelectric production to centers of consumption. Most large hydroelectricity is in remote regions with modest demand.

5. ***Ensure that any future China hydro investment has terms that allow partial purchase of power above 10% for domestic use***. This is now the case with existing export-oriented dams and should not be difficult to negotiate when it is not already in the contract. Import and export prices of power should be similar.

6. ***Continue work on rural grid expansion*** and ***promotion of decentralized energy sources***.

While the suggested steps are all feasible, several are controversial. Comments are made below, in particular on coal and hydroelectric plants because they are the center of much controversy and discussion – much of it warranted.

Comments on Coal Plants

There has been public skepticism concerning new coal generating plants. This is understandable. Many coal plants in the past emitted large amounts of soot and sulfur. Sulfur led to acid rain downwind. Some kinds of coal are also high in mercury, a toxic metal that can poison fish and water supplies. Nobody wants a polluting plant burning millions of tons of coal a year so that others in distant towns can have reliable electricity. However, technology has evolved considerably and new coal plants can be designed to use low-sulfur coal and catch almost all of the ash particles generated from burning. Processing of coal before burning can also remove over half of the mercury. If investors involve the community from the beginning and arrange for some of the output to ensure plentiful local power supplies, there should be more understanding and less resistance to new coal plants. Paying an annual fee to the district or districts affected by the plant for local use would also promote acceptance. Taking community leaders to visit and take videos of clean coal plants in the region might be one way to persuade local communities that coal plants, if done properly, are good neighbors. While coal will almost always be more polluting than natural gas or hydroelectricity, it does have a place in the energy mix and should not be rejected simply because old technologies were dirty. Low sulfur coal most likely will have to be imported. Indonesia is a major exporter and should be a reliable supplier.

It is important to realize that a single coal unit has a usual capacity of 400-600 MW and most coal stations have at least two such units. A typical station might have a capacity of 1000 MW (1 million kilowatts) and run for 6000 hours a year, producing six billion kWh a year. Since a ton of good steam coal produces about 3000 kWh, the annual coal consumption of one station is on the order of two million tons a year or 5-6 thousand tons a day. If the coal is of lower thermal quality, even larger amounts must be used. Handling such large amounts of coal requires either dedicated trains (unit trains) running frequently from a coal mine on heavy gauge track, or ocean transport on large ships that need deep channels and ports with specialized unloading facilities. These are major investments and they have a major impact on the area in which they operate. Putting coal plants in Myanmar coastal locations runs the risk of damage from major cyclones and expenses for flood protection may further raise costs. Furthermore, to ship coal from suppliers in Indonesia or Australia requires larger scale ships and therefore, deep water access not easily found near most Myanmar population centers. These are not reasons to ignore coal, but they help to explain why, carbon and pollution aside, they are not a universal or simple solution to power generation requirements.

Comments on LPG and LNG

The differences between LPG (liquefied petroleum gas) and LNG (liquefied natural gas) are not always clear. LPG is propane or butane gas under slight pressure which turns into a liquid at normal temperatures. It is often used for household cooking and delivered in small cylinders, but can be used in place of natural gas in many generators. It currently sells for $15 to $16 per million BTU (import price) and can be delivered in small ships of 10-30 thousand tons. It does not require elaborate or costly ports or handling equipment. LPG is a plausible transition fuel for gas-fired generators that will be commissioned in 2015-18 but not able to use domestic natural gas until a few years later when extra domestic gas supplies should become available. LPG is also cheaper than kerosene or diesel alternatives.

LNG is super-cold natural gas which has turned into a liquid. It is typically delivered in specialized ships which are really floating thermos bottles, specially designed to handle the very cold liquid. Recently, most LNG tankers have been very large – up to 12 meters (39 ft) in draft and require costly specialized storage facilities on shore, which take several years to build. Because the cost of the ships and the onshore facilities needs to be repaid over an extended period, most LNG contracts are for many years, usually at least twenty. If Myanmar will produce more domestic natural gas for its own use starting in 2020, the cost of domestic natural gas would be less than that of LNG. This would make the large onshore investment in equipment unattractive. Besides this, there are not deep water ports capable of handling large LNG ships close to population centers where electricity is needed. For all of these reasons, LNG is not a plausible fuel for local use in Myanmar unless in the long-term there are inadequate domestic supplies of natural gas for domestic use. This does not currently appear to be the case.

Comments on Large Hydroelectric Projects

The exploitation of hydroelectric sites has been a top-down affair in which local communities have not had much input. This is changing and affected communities, especially in ethnic areas, now expect and should get a role in planning or even investing in “their” projects. Because this is tied into the peace negotiations, this participation often slows down the pace of investment. For example, an investor will often prefer a high dam as this has a better rate of return, but a high dam will displace more area and people with its reservoir. It is also more of a risk downstream if the dam fails. Local groups often argue for dams of medium height or even run of the river dams that do not store large amounts of water. These negotiations are important to the locality but take time to complete. Competent engineers from the Ministry of Electric Power have to be involved to explain the tradeoffs to the affected groups.

In addition, thorough hydrology studies (how much water flows through the proposed dam site – not just on average, but maximum and minimum flows over many years) and environmental assessments can take several years if done properly. This may seem like a tedious detail, but one does not want a dam to underestimate the maximum flow! It could lead to large releases of water and poor management of the reservoir level. These assessments can take 3-5 years to complete. Even then, the influence of water pressure on rock formations causing earthquakes in the region or of downstream sediment deposition may not be well understood.[8]

Once the design and studies and assessments are completed, large dams can take 5-10 years to complete. These intervals are one reason why it takes so long for projects to come online. While hydroelectricity is a low cost source of power with no ongoing carbon or particulate emissions, it is not costless or without risk. This does not mean it should not be developed, but neither should it be rushed.

Perhaps the least risky type of hydro project is "run of the river" dams where there is no dam or a small dam holding only modest amounts of water. This design does little to change the flow of the river. The obvious problem is that during dry periods, there may be little output and using stored water to meet high periods of demand during the day or week is limited or impossible. This design works best if there is a minimum dry season flow or if a large upstream dam provides a reliable flow. There are limited sites in Myanmar that meet these requirements, but they might be fast-tracked since the risks are lower.

There are huge amounts of potential hydroelectric capacity – some estimates exceed 40,000 MW. This is ten times the current capacity of Myanmar from all sources. On the other hand, *if* demand really does need to double every six years for eighteen years, the capacity in 2032 would need to be 32,000 MW. This sounds like an absurdly high amount and is above the high estimate of the Ministry of Electric Power[9], but it would amount to about 2000 kWh per capita, less than the current Thai usage and equal to Vietnam's per capita generation in a few years. Given the long lags in building these dams, it is important to negotiate the ability to purchase significant amounts of power for domestic use, even from dams invested with foreign capital and initially destined for export. Significant amounts of power should be available in twenty years, not fifty.

[8] Sediments are what create and maintain river deltas. If sediment flow ends up trapped behind a reservoir instead of washed downstream to the Ayeyarwady Delta, the Delta could lose fertility and even area to the ocean. This has happened with the Mississippi Delta in the United States. Some dams can be "flushed" periodically to reduce sediment trapped by the reservoir, but a lot depends on design and management.

[9] In 2014, one planning document had a 2030 high case of 14,542 MW of peak demand. This represents an annual compound rate of growth of 10-11% from current peak demand but only 7-8% annual growth from current peak capacity – which is inadequate. If the supply-demand gap is to be closed, the capacity growth will have to exceed demand growth based only on future economic growth.

The question of who should build the hydroelectricity and where is complicated. Chinese groups, based on agreements with the previous government, have contracts to build several large dams at Myitsone and north of that site under favorable terms for the investors. It had been assumed that the cost of building these dams would be close to those in Yunnan, or about $1000 to $1200 a kilowatt. However, recent discussions with CPI suggest a much higher price – perhaps as much as $1800 per kilowatt. This is odd in that steel and cement prices are dropping. It may be useful to have companies from other nations, such as from Europe, also bid on large hydroelectric projects. This competition would help ensure that cost estimates coming from China are realistic. For example Shweli-3, with 1050 MW potential, could be accelerated with foreign investors (who are currently seeking an investment role) and could serve as an upper limit on allowable costs. It is currently slated to be finished around 2020, but this could be accelerated by more intensive effort.

Concluding Comments

The Ministry of Electric Power has highly competent engineers that know how to build out an electrical system and they are getting planning help from international aid organizations and the Japanese and Norwegian governments. There is not a problem of technical capacity. There are, however several issues which slow things down.

One is the price of electricity, which is now charged at a fraction of the cost of new power. The Ministry (or the national utility if it is corporatized) is in a situation where the more new non-industrial power it sells, the larger its losses. This leads investors to (rationally) demand a government guaranty for the purchase of new power at a realistic price. If this condition is not met, it is uncertain that there will be enough funding to buy the contracted amount. Until prices charged to customers cover costs of new power, government guaranties are needed.

The Ministry is completely aware of this and tried to raise the price of electricity. The policy was correct but the execution was clumsy – little groundwork was laid with opposition groups in Parliament or consumers. There was a backlash and reversal and then more modest steps. What is needed is a five year plan to gradually increase electricity rates to their marginal cost – that is the cost of new power. This needs to be explained and negotiated beforehand. A “lifeline” rate of 35 kyat per kWh can be kept for households with low total consumption, say less than sixty kWh of usage a month. If there were eventually five million such households consuming 500 kWh a year, the total subsidy cost would be about $200 million a year. This should be transferred to the Ministry or utility either as cash or through low-cost gas or hydroelectricity, providing it is passed on to poor consumers. (Some observers believe that one reason for high costs and losses is that exemptions from payment or low rates are given to influential customers. If half of all “losses” of power were eliminated, this alone would pay for most of the deficit.) Over time, more and more households will want to consume more electricity than the cutoff lifeline amount and the lifeline subsidy costs will diminish. Special deals should also be available between private generators and factories in industrial zones. If buyer and seller agree on a premium price to sell reliable power, this should be legal.

A second problem is that the Ministry is currently performing two roles. On the one hand, it is a regulator. It sets the conditions for private participation in stand-alone generators or in public-private partnerships. On the other hand it is a player, itself generating and selling power. In most cases, these functions are separated to avoid conflicts of interest. Creating a national utility that was corporatized and could even sell minority shares to outsiders is one possibility. In some cases, this utility sells its generating assets and concentrates on the transmission and distribution of electricity. In others, it keeps some legacy plants but most new power generation is purchased under contracts supervised by the Ministry. More clarity and guidelines are necessary because it is not always clear now what is allowable. Clear laws and guidelines would speed the process of increasing supply.

A third problem – and it is critical – is that the Ministry of Electric Power has about 1400 MW of natural gas-fired capacity said to be coming on line in 2015-2016 but we were told there is not enough natural gas available to run all of these projected plants. Unless Myanmar is willing to abrogate natural gas export contracts – a severe and undesirable step even if previous agreements were unwise – it will have to either curtail its expansion plans or temporarily use more expensive fuels such as kerosene/diesel fuel or propane to run the generators. Since propane is about half the cost of kerosene, it is preferred. Going forward, explicit coordination between electricity generation choices and the availability of fuel should be better coordinated beforehand.

Finally, there has been almost no discussion of the regional inequalities of current electricity policy. The current low price of electricity restricts expansion to underserved states and villages. In 2010-11, the per capita availability of grid electricity in Yangon was 170 times that of Rakhine and fourteen times that of Ayeyarwady region. By insisting on electricity prices below the cost of new power, there is not enough money to provide the same amount of power (or at least the opportunity to buy the same amount) as in more favored regions. The same argument applies to villages or even households – still 70% of the total – who have no access to grid electricity. The populist argument for cheap power is not only wrong - it is actually an impediment to national equity. So long as a “lifeline” rate is available, there is no reason why others should be subsidized while most go without.

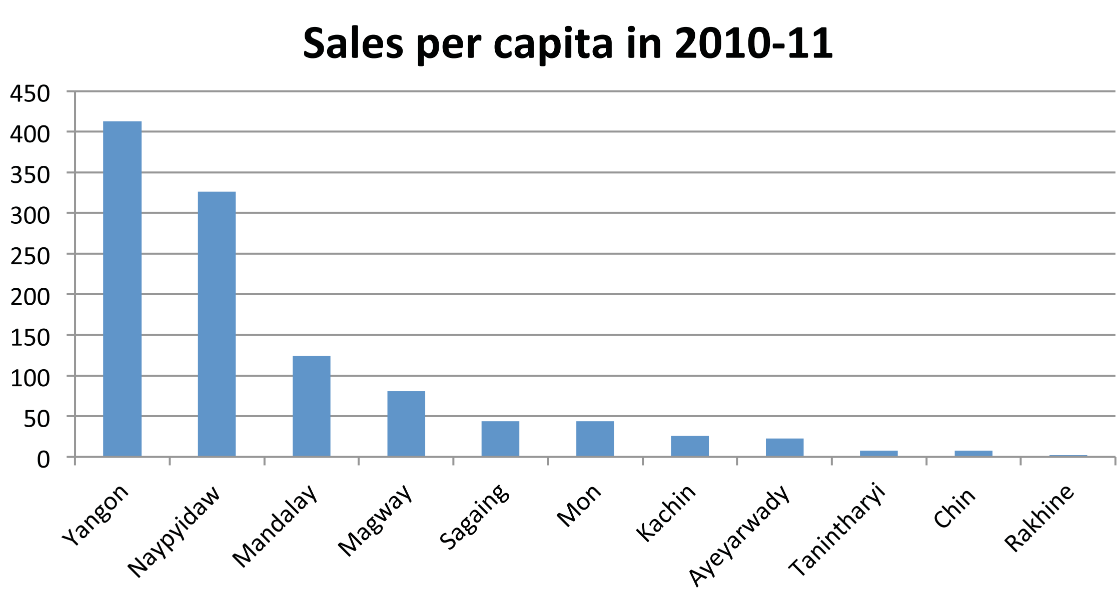
Appendix 1: Grid Electricity Sales by Selected Regions in 2010-2011

Table of Grid Electricity Sales by Selected Regions in 2010-2011

Region	Sales (Million kWh)	Population (Millions)	Sales per capita (Kilowatt-hours pc)	% of Yangon
Yangon	2893	7.0	413	100
Mandalay	1038	8.4	124	30
Magway	454	5.6	81	20
Nay Pyi Taw	359	1.1	326	79
Bago	346	6.0	58	14
Shan	311	5.7	55	13
Sagaing	285	6.5	44	11
Ayeyarwady	226	8.0	23	6
Mon	136	3.1	44	11
Caching	42	1.6	26	6
Tanintharyi	14	1.7	8	2
Rakhine	8	3.3	2.4	0.6
Chin	4.5	.55	8	2

Sources: Myanmar Initial Energy Assessment, p. 56 for electricity sales (ADB)
Myanmar Agriculture at a Glance, 2013, p. 13 for population (Ministry of Agriculture)
Per Capita sales and % of Yangon from calculations

Graph of Per Capita Electricity Sales (kWh per capita) by Selected Regions in 2010-11



Source: ADB "Myanmar Initial Energy Assessment" 2012

Note that relatively little of the current consumption is in the north of the country where much of the hydroelectricity is located. This will necessitate building expensive transmission lines to bring much of the northern hydro to centers of heavy consumption. This makes gas or coal relatively more attractive in the south, although smaller "local" hydro is competitive in these areas.

The other point is that current off-grid alternatives, such as household-level solar, are relatively expensive compared to subsidized grid prices but much less than diesel. A 100 watt collector and battery can cost as little as $200, although the cost with a proper controller, better battery and good quality panels is closer to $450. This will produce 150-200 kWh a year, depending on location – the Dry Zone has less rain and more sun. If capital costs are 2% a month to households – and this is modest – then even the cheaper system costs $50 a year plus replacements for batteries, resulting in an effective electricity cost of at least K 300 per kWh or nearly ten times the current utility cost for most households with central connections. While larger solar systems have lower interest or capital costs, the "solution" of solar at a household level, while desirable, is not cheap in terms of cost per kWh. While household solar is much better than diesel or nothing, it is not an excuse to avoid the rapid extension of the central grid, which also provides more power on demand. Prices should be brought in line with costs so that investment to cover most households is possible.

Appendix 2: Electricity and Real GDP growth in Indonesia and Vietnam

From 1980 to 1990, Indonesia had real per capita GDP growth of 3.6% while electricity per capita consumption grew at a rate of 13.4%. The ratio of electricity to GDP growth (both per capita) was 3.7. Indonesia in the 1980's had real per capita GDP equal to that of Myanmar in 2013. During this period, Indonesia invested heavily in electricity but still failed to meet the actual demand of those connected; in addition coverage of population in remote islands and villages saw only moderate progress. Even in 2000, only about three-fifths of households were connected to the grid.

From 1990 to 2010, Vietnam had real per capita GDP growth of 5.6% while electricity per capita grew at 12.5%. The ratio of per capita electricity to per capita GDP growth was 2.2. In the 1990's, Vietnam had a level of real per capita GDP similar to that of Myanmar in 2013. During this period Vietnam invested heavily in electricity and blackouts, while not uncommon, were reduced while extension of national grid power to more than 95% of all communities was accomplished. Electricity demand growth in Vietnam is projected at 10% a year in this decade, even with real GDP growth slowing to 5-6% and in spite of an already-high level of electricity use per capita.

In light of the experience of these two ASEAN economies, it is reasonable to expect that for Myanmar a 7.5% GDP growth and 6.5% real per capita GDP growth would imply electricity demand growth of at least 15% per year, or a minimum per capita electricity-to-income growth ratio of 2.3. This does not assume major development of heavy industry but does assume an extension of grid electricity to those not now served and a reduction in blackouts. Both increased service and reduced blackouts are part of the planned improvement in electricity service.

Appendix 3: Fuel Costs and Electricity Prices

Thermal electricity can be generated using different fuels. The most familiar is the diesel engine, which uses 0.3 liters per kWh in most engines, though the newest ones can reduce this to 0.27 liters. When diesel cost $1 a liter, this meant that just the fuel cost of diesel would be $0.30 or nearly 300 kyat/kWh. However, recent declines in the price of crude oil and thus refined product have allowed Singapore wholesale diesel prices to fall to as low as $.60 per liter, or a fuel cost of only $.18 per kWh. Capital, maintenance and operating costs add to this – though they will depend on the intensity with which the generator is used. The efficiency of diesel is 33-37%.

Gas generators can also use fuels such as LPG (methane and related gases under slight pressure at normal temperatures), kerosene or diesel as well as natural gas. Natural gas is preferred since it is cheaper and cleaner. A gas generator can be single cycle (like a jet engine) or combined cycle, in which the waste heat from the single cycle generator is used to make more electricity in a steam cycle. The efficiency of a single cycle gas generator is 35% to 38% while a combined cycle generator (which is more expensive to build and takes longer to put into place) can run 50-55%. At high fuel prices, combined-cycle is cheaper overall.

The cost of natural gas varies but pipeline gas ranges from $7 to $12 outside of North America for 1 million BTU or 1000 cubic feet. A combined cycle generator can extract 160 kWh from that much gas, so its fuel cost would range from 4 to 8 cents per kWh. A single cycle generator might get only 105 kWh from the same amount of gas, and its fuel cost would be from 7 to 11 cents per kWh. Capital, maintenance and operations costs would be added to the fuel cost to get total cost of the power generated; distribution costs have to be added to get the retail cost. However, prices of industrial electricity are in the range of actual costs of combined-cycle gas power.

LPG costs $700-$800 per ton in bulk amounts delivered to Yangon. There are about 50 million BTU per ton, which works out to $14 to $16 per million BTU. This is 1.5 times as much as pipeline natural gas costs so the fuel costs would be 1.5 times more than pipeline gas. If LPG were used in a combined cycle unit, the fuel cost of the electricity would be 100 to 110 kyat per kWh. This is higher than the current price of grid electricity for consumers but not industrial customers. For households, using this or other liquid fuels would create losses that require subsidy or higher prices.

To summarize:

Normally, diesel is the highest cost but most easily produced form of electricity. As diesel fuel prices fall, the fuel cost of diesel electricity falls as well and it is now about twenty cents (200 kyat) per kWh at world wholesale prices, but **not** local retail prices. The delivered cost of diesel electricity has to include distribution costs (if not on-site) and capital and operation costs. Together, these exceeded forty cents in the past and are at least thirty cents now.

Production from single stage gas generators is a bit more efficient than diesel and also can use a variety of fuels (LPG, natural gas and kerosene) as well as diesel. These generators can be set up in a few months but waste most of the fuel energy by producing heat as well as power. They are less expensive than diesel but normally have a larger minimum size so are better for large companies or utilities.

Combined cycle units are the most fuel efficient and produce the lowest cost thermal electricity at current gas and liquid fuel prices. They cost more in investment per kilowatt and take longer to build and work best for utility connections or large industrial zones.

Solar electricity is an interesting alternative in the Dry Zone as a backup to hydroelectricity, especially if there are financing alternatives available at low interest rates from international development banks keen to invest in renewable energy projects and from national Export-Import banks eager to support their manufacturers.

Power purchased from China could be available as quickly as transmission lines could be built and terms agreed to with the Southern Grid, the Yunnan utility. This should be cost-competitive in the north with any other source of electricity. The same is true of domestic hydropower, but building this in quantity will take at least five years and as much as a decade.