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Case Study

Vietnam Electricity

<u>Background</u>

Vietnam has experienced rapid increases in demand for electricity for at least two decades and supply has strained to keep up. From a mere 8.7 million megawatt-hours (MWh) in 1990, output soared to 26.7 million MWh in 2000 and a projected 77.2 million MWh in 2008.[1] This torrid rate of growth of 14% a year since 2000 may or may not continue, given the uncertainties in the global and domestic economy. However, with a per capita electrical consumption of less than two-fifths of Thailand's, there is clearly room for continuing demand growth.

There has been a pattern of blackouts in Vietnam, particularly in the dry season. This can be traced to at least two causes. One is a high ratio of peak to off-peak demand. The maximum demand was 11,500 MW while off-peak is only about 6800 MW. A big difference between peak and off-peak demand requires investing in a lot of seldom-used capacity. That capacity, if it uses diesel oil, is very expensive with high oil prices. The other way is to use single stage gas turbines, as these also have low capital costs. Combined cycle gas plants are more expensive to put in place, but are also more fuel efficient, and these are used more for base load and intermediate-load power.

There is also a heavy reliance on hydroelectric power, which accounts for 40% of capacity and 25% of output. Current hydro facilities have limited reservoir capacity – a supply of a few days or one week at normal rates of use. Thus, during the dry season when flows into the reservoir are a small fraction of the wet season, it is not possible for full hydroelectric output to be maintained. While this problem can be and has been solved by installing backup thermal power, investors who build such installations will require returns equivalent to those combined cycle gas or coal plants that are normally used for base load (nearly full time) or intermediate load operation in other countries. Since EVN (the state electrical company) prefers to use hydropower when it is available since its costs them almost nothing extra, it is difficult for private investors and EVN to reach an agreement on terms for buying thermal power from coal or gas. Providing cheap and reliable electricity will require combining thermal and hydro power efficiently.

[1] These data refer to production. Sales or consumption are 12-13% lower than production due to losses. Losses have been falling as a share of production, and are expected to fall to 7.5% by 2015.

This case was written by David Dapice, Economist at the Vietnam Program, Harvard Kennedy School, The case is intended to serve as a basis for class discussion rather than to illustrate effective or ineffective handling of an administrative situation.

If base load thermal power is not built, the fallback option has been to install diesel generators or single stage gas turbines.[2] Modern diesels can get four kilowatt-hours per liter of fuel (though most used in Vietnam get less), but with the rising price of oil, this is becoming a very expensive option in spite of their low capital costs. The cost of electricity from a small diesel generator can easily exceed 30 cents per kWh, while the prices normally charged by EVN are 5-6 cents per kWh.[3] In any case, it is an unwanted burden for businesses to have to invest in backup capacity, fuel storage and worry about operations and maintenance. Vietnam's competitiveness will depend in part on being able to provide reliable electricity at a price no higher (if not lower) than that of its neighbors.

Thailand provides an excellent country for a comparison with Vietnam. It started its broad electrification and economic growth earlier and has a much larger installed base of generating plants which include hydroelectric and thermal – both gas and coal. EGAT, the Thai power company, is well regarded and provides electricity fairly reliably and at a competitive but unsubsidized price. While its current projected growth rate of 5-6% a year is much lower than Vietnam's, its 28,530 MW of installed capacity is more than double Vietnam's. (This includes EGAT and independent generating companies.) However, unlike Vietnam, hydro is only 13% of total power capacity, with thermal (coal and oil or gas) at 34% and combined cycle gas at 50%.[4] Their 2008-2013 plan has 54% from combined cycle gas, 14% from coal, and 31% of power purchased from Laos – mainly hydro. The remainder is small renewable sources. An allowance is made in their planning for a 20% reserve over peak demand. This balanced plan is judged to be least cost and will provide nearly 13,000 MW of new capacity from March 2008 to March 2013, though some of this will replace capacity to be retired. Gas is mainly provided from offshore wells, and Chevron has just signed a contract to develop a new field. The cost for gas in early 2008 averaged over various domestic fields and contracts was \$5 per million BTU. The range was from \$1.60 to \$6.58/ million BTU. Imported pipeline gas, however, was nearly double the domestic cost and future LNG contracts were in the \$12-\$15 range.[5]

The Vietnamese government has responded to surging demand and blackouts by approving an astonishing 48,000 MW of capacity for the period from 2007 to 2015 – more than four times the 2006 total capacity. Of this total, only 13.4% is from gas, the balance being for hydro (1/3) and coal (over ½). The coal plants include those using both domestic and imported coal. **The two major questions for this case are (1) what mix of electrical generating capacity will <u>reliably</u> supply the demand in Vietnam at the least cost; and (2) how can this be contracted for or constructed? That is, what prices need to be charged under what terms?**

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[2] In some countries, thermal base load at off-peak is used to pump "used" hydroelectric water back up into its reservoir for use at peak periods. This pumped storage shifts energy to when it is needed. Hydroelectric plants are very quick to respond to changing electricity needs. About 4 kWh of thermal off-peak base load are used to produce 3 kWh of peak load hydroelectricity. A lower reservoir is needed to hold the water.

[3] Prices are sometimes higher if rural cooperatives sell EVN power on to remote customers. In other countries, time-of-day pricing is used to limit peak-load demand.

[4] The remaining capacity is renewable and diesel.

[5] Natural gas, if liquefied, can be exported long distances and normally costs (for 1 million BTU) 40% to 80% of the same heat value of crude oil. Relative to coal, gas is from 1/3 to 3 times more for the same heat value. Costs per million BTU for oil, coal and natural gas are in Annex V.

Prices and Plans

One major problem that EVN has is that it costs more, on average, to add and deliver a kilowatt-hour of electricity than they are now allowed to charge for it. There is little change in projected energy prices in Vietnam going forward, and electricity prices are often one way used to help "control" inflation. To catch up with Thailand's electricity price of about ten cents per kWh, would require a 50% to 70% price increase for EVN. While EVN's historic hydropower is very low cost, the advantage of blending expensive new energy with older low-cost energy rapidly diminishes as demand grows so quickly. The appendix shows illustrative costs for new power from hydro, gas and coal units. In practice, the cost of coal or gas fuel and generating plants and the cost of finance (the interest rate and return to equity capital) will determine the actual cost of generating new supplies. However, a retail price has to include not only generating costs but also transmission, distribution and overhead costs. These are 2-4 cents per kWh in most cases except remote rural areas.

When there is a shortage, it is normal for prices to rise if there are not price controls. One solution that could be adopted would be to raise the buying price of EVN until there is adequate supply at all times. The problem with this solution is that private investors do not normally commit to building expensive electricity generators, and the gas fields or coal mines that supply them, without long-term contracts. But since the long-term cost of production is above what EVN can charge[6], EVN is reluctant to commit to long-term contracts that cover actual costs. The result is often a stalemate. However, full and immediate decontrol of power prices to consumers seems to be a difficult choice, though a phase-in might make such a choice eventually compatible with paying for new supplies.

Given that negotiation and long-term contracts are required, what considerations are relevant as Vietnam weighs its choices? The following is a partial list:

1. The cost of finance: Vietnam has had access to large amounts of capital at low cost. This tends to favor generating choices which have heavy initial investment costs but lower operating costs such as hydro, nuclear and perhaps coal. If this era of low cost finance is ending, then less capital intensive choices, even if somewhat more expensive to operate, such as gas, might become more attractive.

2. The cost of fuel[7]: Neither hydro (which uses no fuel) nor nuclear (where uranium is a small part of total costs) are of concern here. Natural gas can be sold at a price tied to oil or on a long-term agreed-upon price. If a buyer expected oil prices to drop, a variable gas price tied to oil would be preferable. If a buyer expected oil prices to rise, a fixed price contract would be favored. Recent gas prices in the US and Europe have been around $10 to $12 per million BTU, and these supplies are mainly domestic. Recent prices in Thailand from Thai fields have been about $5-$7 per million BTU, but $8-$10 (delivered pipeline price) from Burmese sources. A Thai LNG (liquefied gas) contract with Qatar will cost $15 per million BTU. Steam coal is

[6] In March 2008, EGAT, the Thai electrical utility stated that it had a power charge of 2.44 baht/kWh and a fuel tariff of .69 baht, for a total of 3.13 baht per kWh or 10 cents (US) at March 2008 exchange rates. The retail electricity price includes the generating costs and also overhead, transmission and distribution. In early 2008, the generation cost of coal was 2.45 baht/kWh; gas was 2.80 baht and fuel oil was 5.32 baht.

[7] One million BTU of combined cycle gas produces about 150 kWh, while the same heat value of coal produces about 115 kWh. That works out to a coal fuel cost of 2-4 cents per kWh at $60-$120 per ton and a gas fuel cost of 5 cents per kWh with gas at $7.50, and 10 cents per kWh with gas at $15 per million BTU.

historically purchased under long-term contracts, with the boiler design of the coal plant optimized for the type of coal contracted for. However, volatile prices have resulted in more spot market purchases or shorter contracts. Since many countries have coal reserves, long–term prices tend to be more competitive and closer to the supply cost than for oil prices. However, due to the jump in demand for coal, recent contract prices have been much higher than the $20-40/ton often charged in recent years and are now closer to $60-80 or even over $100 per metric ton.[8] (Prices are FOB.) However, Vietnamese coal exports in 2007 averaged only $31 per ton. It is unclear if future coal plants in Vietnam will use imported or domestic coal supplies as exports are already shrinking and long-term supplies are uncertain.

3. The cost of investment: Given the previous two variables, the cost of investment is the third that will help to determine the choice of plant type. Costs for hydro depend on the site chosen, but are normally about $1500 per kW if interest is included during construction. Coal normally costs about $1200 per kW for large modern plants of high efficiency and low pollution, but smaller Chinese plants are only half as expensive per kilowatt. Combined cycle gas is about $600 per kW. Construction times are variable but quite long for hydro; 3-5 years for large coal plants and 2 years for combined cycle plants. Interest on funds expended during construction has to be added onto the materials and labor cost to get a total cost for each type of plant.

4. Carbon charges: This is a speculative item but one which should be considered. Though poor countries such as Vietnam will not be required to pay for their emissions in the medium future, they might be able to get paid for avoiding emissions. If there were a “carbon trading system” switching away from coal might prove profitable, since that it is the heaviest carbon source of any fuel.[9] Nuclear and hydro would benefit most from this but gas would be twice as clean as coal per kWh from a carbon perspective.

5. Flexibility: There is uncertainty about the growth rate of demand for electricity, especially as one goes deeper into the next decade. If a nuclear plant is decided upon, it requires starting five to ten years before it comes online and its size is often thousands of megawatts. Combined cycle gas, on the other hand, can be put in place within two years and in efficient sizes little more than 100 MW. Coal tends to be between gas and nuclear, with 300 to 600 MW plants taking 3-4 years to build. Hydroelectricity sizes are quite variable, from under 100 MW to Son La’s 2400 MW. The time required for construction is typically longer than for 300 MW coal, except for the smaller hydro units. In general, a less risky approach is to build units closer to when they will be needed. On the other hand, strong demand growth allows economies of scale from larger plants to be realized, and a cushion of extra power above likely peak demand is normal to ensure reliability.

[8] In early 2008, a combination of floods in Australian coal mines and cold weather and coal shortages in China, partly associated with price controls, drove spot steam coal prices up to over $140 a ton and contract prices for coking coal to $300 a ton. It is unclear how long these unusual prices will persist. Japanese utilities recently signed contracts for $130/ton. Prices for US steam coal are much lower, but limited quantities can economically be exported across the Pacific.

[9] There are various schemes to gasify coal and strip off the CO2 and inject it underground if the geology permits, or even to use it to grow algae biodiesel! These technologies are interesting but beyond the scope of this case. They may become relevant in a five year time frame however.

6. Technical considerations: Issues of pollution, reliability, and ease of varying output of the plant are also important. Many hydro plants have very low firm power due to uncertain dry season production. (Firm power is power that is almost always available for use. If the reservoir water level falls below the turbine intakes, the power production is zero until the water level rises.) On the other hand, hydro and gas can vary output quickly, while coal is better running at a nearly constant rate. These details matter in designing an integrated system.

7. Diversification: It is dangerous to rely too much on any single method of generating electricity. It is usually safer to have a mix. If gas alone were used, an earthquake might disrupt supplies by destroying pipelines. If hydro predominates, a severe drought could cause supply problems. Even coal, as was seen in early 2008, might suffer from shortages, even for long-term contracts.

Getting Prices to Costs

If EVN is going to be able to contract for sufficient power, an adequate price has to be charged. Different strategies could be employed, starting with higher prices for commercial/industrial users and higher household monthly use levels. If this were combined with more reliable power (reducing the need for backup generation), the total cost to larger consumers might actually be lower than it is now. Rather than simply raising all electricity prices to the marginal cost of new power, a variety of transitional strategies could be examined that might provide EVN with a politically feasible path to reliable and adequate supplies. There are, after all, economic and social costs to blackouts.

The proportion of total output that is hydroelectric will heavily influence the cost of gas or coal fired electricity. If hydro is the single largest source, then extensive idle time will be inevitable for thermal stations, since the wet/dry season power output ratio is so uneven. While coal can be stockpiled and gas output can vary from a developed field by +/- 30% from average, the investments would be idle longer if hydro were preponderant. The exception to this is Son La, a large hydro project in the north[10] with a very large reservoir that could produce more evenly over the year.[11] However, that single project is only about 15% of hydropower to be developed in the 2007-2015 period. So, part of the solution to reliable supplies is finding a role for both hydroelectric and thermal power.[12]

[10] While there is a high voltage line connecting north and south, it is of limited capacity. As a result, the northern and southern markets are semi-independent and might be analyzed separately. Most hydro power is in the middle and north of the country. The major choice in the south is between coal and gas. Gas is now planned at 4800 MW and coal at 8400 MW in the south to 2015. However, over 6200 MW of hydro capacity is planned for the middle region, and that, if connected to the south, would make thermal capacity redundant for much of the year.

[11] Another complication, not discussed here, is what happens to dry season flows of rivers if the Himalayan ice fields melt and/or foreign high level diversion projects take dry season water from rivers upstream.

[12] One possibility is to use hydropower for intermediate and peaking power; coal for base load and combined cycle gas for both base load and intermediate power, especially in the dry season.

Annexes:

I. Illustrative costs of hydro, coal and gas electricity – capital, fuel and O&M.
II. Coal reserve, production, price and import information.
III. Supply over time and projected; by type of user and type of fuel.
IV. Planned/ approved investments by region and hydro, coal and gas.
V. Trends in Oil, Natural Gas and Coal Prices

Annex I: *Illustrative Costs of Hydro, Coal and Gas-Fired Electricity Units (All Costs are per Kilowatt of Capacity or kWh for fuel and O&M)*

	Capital Cost/KW	Years to Build	Variable O&M/kWh	Fixed O&M/kWh	Heat rate per kWh (Efficiency)
Large Coal	$1200	4	0.4 cents	0.4 cents	8800 BTU (39%)
Chinese Coal*	$600	4	0.5 cents	0.5 cents	9000 BTU (38%)
Combined Cycle	$600	3	0.2 cents	0.2 cents	6600 BTU (52%)
Gas Turbine	$400	1-2	0.3 cents	0.4 cents	9000 BTU (38%)
Diesel	$200	1	0.5 cents	0.5 cents	9000 BTU (38%)
Hydroelectricity	$1400	3-6	0.1 cents	0.1 cents	-

*Estimate for 600 MW fluidized bed combustion Chinese generator. The Chinese O&M costs are estimated.

Most hydroelectricity units can only be run for about 4000 hours per year, while coal and combined-cycle gas units are often run as base-load for over 6000 hours per year. Gas turbine (single cycle) and diesel are peaking units, and can be assumed to run for 2000 hours per year or less. The cost of coal (25-27.5 million BTU/metric ton) can be estimated at $40, $80 and $120 per ton (low, medium and high price scenarios); the price of gas per million BTU at $6, $10 and $14; and the price of diesel per liter at 60 cents, 90 cents and 120 cents. The fuel cost can then be estimated per kilowatt-hour of electricity:

	Fuel Costs in US Cents per KWH			***Fuel prices***		
	Low	Medium	High	Low	Medium	High
Large Coal	1.4	2.8	4.2	$40	$80	$120 (per ton)
Chinese Coal	1.44	2.9	4.3	$40	$80	$120 (per ton)
Combined Cycle	4.0	6.7	9.3	$ 6	$10	$ 14 (per mln BTU)
Gas Turbine	5.4	9.0	12.6	$ 6	$10	$ 14 (per mln BTU)
Diesel	15.0	22.5	30.0	$.60	$.90	$1.20 (per liter)

It is useful to calculate the per kWh fixed cost of generating electricity in addition to the fuel cost. In order to do this, we have to know the cost of the original investment, the interest rate and/or cost of equity, the number of hours used per year, and the lifetime of the generating plant. In the table below, a 10% cost of capital and equity is assumed.

Fixed Costs per Kilowatt and Kilowatt-Hour

	Capital Cost Per Kilowatt	Years in Service	Hours per Year	Fixed Cost, cents per Kilowatt-hour
Hydroelectricity	$1400	40	4000	3.5
Large Coal	$1200	30	6400	2.0
Chinese Coal	$ 600	20	6000	1.2
Combined Cycle Gas	$ 600	20	6000	1.2
Gas Turbine	$ 400	15	2000	2.6
Diesel	$ 200	10	2000	1.6

In order to arrive at a total cost of generating electricity, all costs must be considered: the fixed cost, the fuel cost and the O&M costs. ***The medium fuel price scenario is used for gas but the high diesel and coal price scenario is used below.***

Total Costs of Generating Electricity in Cents per Kilowatt-hour

	Fixed	Fuel	O&M	Total
Hydroelectricity	3.5	- -	0.2	3.7
Large Coal	2.0	4.2	0.8	7.0
Chinese Coal	1.2	4.3	1.0	6.5
CC Gas	1.2	6.7	0.4	8.3
Gas Turbine	2.6	9.0	0.7	12.3
Diesel	1.6	30.0	1.0	32.6

These are only indicative prices based on the assumptions. It is quite possible to get different costs per kilowatt-hour if different assumptions are made.

Annex II: *Coal in Vietnam: Imports Ahead?*

Vietnam produces about 40 million tons (MT) of coal a year and exports 75-80% of it. This may not continue. Priority will be given to satisfying domestic demand, which is expected to rise to 35- 42 MT a year by 2010 and 80 MT by 2025. By 2010, coal exports are expected to fall to 12 MT and cease altogether after 2015. Even the 2010 export level would depend on raising coal output to up to 54 MT, but output in 2006 and 2007 and the first part of 2008 has stayed around 40 million tons at annual rate.

Complicating the coal picture is the difference between hard coal (anthracite) which is mainly used in steel making and soft coal (steam or thermal coal) used for generating power. Vietnam’s coal is primarily anthracite. While it is possible to use hard coal for power, it is a little like feeding caviar to chickens- it works but is not a good idea! Recent prices for anthracite coal in Asia under a one-year contract were over $300 a ton, while soft coal usually costs (well) under $100 a ton, though lately it has sold for $120. In Vietnam, coal prices were recently raised to about $35 a ton for local industrial buyers.

There are supposed to be vast coal resources in Vietnam, but the level of proven reserves is only 150 million tons, and this figure has not been changed for many years. While various sources refer to over 30 billion tons of probable reserves, many of these are located hundred of meters deep in the Red River Delta. There has to be more exploration, drilling, mines created and years of installing supporting infrastructure in order to get at it and bring it to the surface. In fact, it is not known for sure just how much of the coal is economically useful – how much is worth extracting at current prices.

Australian coal companies are the "swing" suppliers for China and much of Asia. They foresee Vietnam needing to import coal for its power plants – they estimate 20-30 million tons a year in the 2012-2015 period. If anthracite can be exported from Vietnam at premium prices, it would certainly make sense **not** to become self-sufficient in coal, but rather to export the high priced coal and import the cheaper coal. While steam coal was quite expensive during the first quarter of 2008 due to Chinese demand and mine flooding in Australia, it may eventually come back down in price, though Japanese utilities did sign steam coal supply contracts for $135 a ton early in 2008. On the other hand, US coal prices varied from about $50 to $115 a ton in May 2008.[13] Any of these prices are well below the anthracite prices of over $300 a ton now locked in supply contracts between POSCO (a Korean steel company) and Australian producers.

If coal costs $100 a ton instead of $35 a ton, the fuel cost will be triple and more efficient plants would become desirable, even if they were more expensive. A modern efficient coal plant requires about 8800 BTU for one kWh while a less efficient coal-fired plant might require 11,000 BTU per kWh. Pollution is also less from the more efficient plant.

Annex III: Supply of Electricity in Vietnam (in billions of Kilowatt-hours)

	1990	1995	2000	2005	2006	2007	2008est.
Production	8.79	14.67	26.7	52.1	59.1	67.1	77.2
	2010	2015	2020	2025			
Projected	105.8	227.0	363.0	484.0			

Electric Generating Plant Situation in 2007:

	# Plants	MW Capacity	% of Total
Hydro	14	4487	36.6
Coal	6	1630	13.3
Gas	4	4746	38.7
Oil	3	575	4.7
Others	NA	832	6.8
Total	*27*	*12,270*	*100.0%*

In 2004, hydroelectricity accounted for 18.1 billion kWh (39.2%); coal for 7.2 billion (15.6%) and oil/gas for 20.9 billion kWh (45.2%). This includes EVN-produced and also purchased electricity. In 2004, industry and construction accounted for 45% of demand; residences for 45%; agriculture for 1% and commerce/other for 9% of total electricity demand.

Sources: Asian Development Bank for 1990-2006 production in Key Indicators 2007. For projected production and type of generating plants, data is taken from the website of the 2008 Vietnam Electricity and Coal Forum and Exhibition, which is to be held in Hanoi from October 29 to November 1st. (www.cpexhibition.com/energy/08/energyo8.htm) For 2004 sources and uses of electricity, p. 11-12 of Power Strategy: Managing Growth and Reform, (World Bank 2006) was used.

[13] There are several different types of coal with various amounts of heat value (measured in BTU per pound) and sulfur levels. Transport costs also influence the mine-mouth cost of each coal.

Annex IV: Planned Investments in Vietnam from 2007 - 2010 (in Megawatts)

	Hydro	Coal	Gas	Total
Capacity	5726	4490	3404	13620
(%)	42%	33%	25%	100.0%

Planned Investments from 2007 to 2015 in Vietnam (in Megawatts)

Capacity	15389	25890	6404	47683
%	32.3%	54.3%	13.4%	100.0%
Of which				
North	5911	11090	0	17001
Middle	6479	2400	104	8983
South	954	12400	6300	19654

Source: EVN. This list includes both 51 EVN and 76 IPP projects. There are 2045 megawatts not allocated by region. Note that power will come on-line according to the investment plan in each time period.

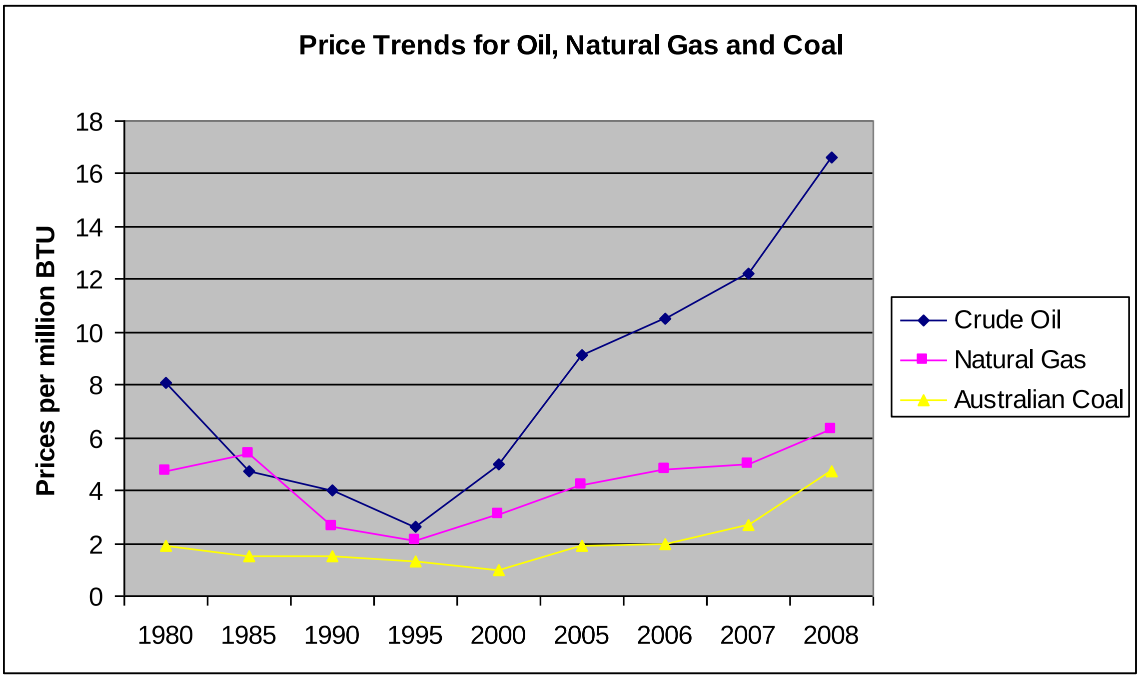
Annex V: Price Trends for Oil, Natural Gas and Coal

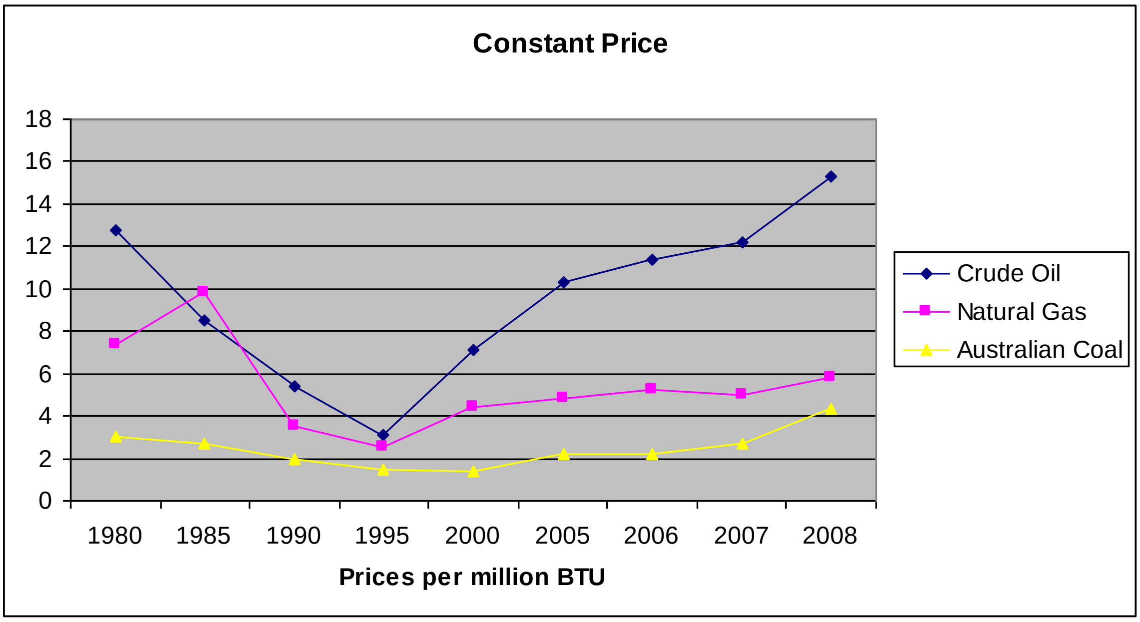
	1980	**1985**	**1990**	**1995**	**2000**	**2005**	**2006**	**2007**	**2008**
Crude Oil ($/barrel)	$47	$27	$23	$15	$28	$53	$64	$71	$96
Natural Gas ($/MMBTU)	$4.7	$5.4	$2.6	$2.1	$3.1	$4.2	$4.8	$5.0	$6.3
Australian Coal ($/ton)	$51	$40	$40	$34	$26	$51	$53	$70	$124
(World export price index)	63.2	55.0	73.4	85.1	70.8	88.2	92.4	100	108.4

Real Energy Prices

Crude Oil ($/barrel)	$74.4	$49.1	$31.3	$17.6	$39.5	$60.1	$69.3	$71	$88.6
Natural Gas ($/MMBTU)	$7.4	$9.8	$3.5	$2.5	$4.4	$4.8	$5.2	$5.0	$5.8
Australian Coal ($/ton)	$80.6	$72.7	$54.5	$40.0	$36.7	$57.8	$57.4	$70.0	$114.4

Sources: IMF International Commodity Series; Crude Oil is blended Dubai, Trent, and West Texas Intermediate; Natural Gas, priced in US $ per million BTU is Russian gas from 1980-90 and Indonesian LNG to Japan for 1995-2008; Coal is Australian export steam coal with 26.4 million BTU/ton. The 2008 figure export price index is estimated by IMF staff as of April 2008 from the World Economic Outlook database. The 2008 energy prices are January to March averages.





Note: All data from IMF. A barrel of crude oil has 5.8 million BTU

Questions for Discussion:

1. How secure are the estimates for future growth? Would prices closer to long-term supply and distribution costs of about ten cents per kilowatt-hour change the growth rate? (If electricity prices rise relative to all prices by 10%, electricity demand drops 1-2% in the short term and 3-6% in the longer term. The opposite is also true – if electricity prices are stable and others rise, the relative cheapness of electric power will drive consumption higher.)
2. How fast would growth have to proceed to use up most of the capacity planned to be available in 2010? (Assume 4000 hours a year for hydro and oil/other capacity; and 6400 hours/year for coal and gas.) How much reserve capacity should there be, given the large amount of hydro capacity with uncertain dry-season production?
3. If demand were lower than projected, what is the best mix from EVN's point of view? How would EVN's choice of generating sources influence returns to IPP's?
4. What is a rational pricing stance for EVN to offer in negotiations given the costs of production for IPP's and the allowable electricity price that EVN can charge?
5. Should EVN encourage more hydroelectricity? (It is the cheapest source when available, according to the cost calculations, but may become increasingly unreliable in the dry season as Himalayan glaciers melt completely and dry season river flows fall.) Should it rather promote more thermal? (They are more reliably available and might help avoid blackouts in the dry season.) What is the best way to encourage one type of generation or another?
6. What are the best sources of thermal supply? Does your answer vary by region? Does you answer depend on the prices of different fuels? (That is, suppose the price of one fuel stayed in the medium scenario, but another fell to the low scenario.)
7. Suppose an IPP were offered a chance to sell electricity at five cents per kWh to EVN for up to 6500 hours a year with a minimum guaranty of 3000 hours. What kind of IPP (or generating plant) would find this possibly attractive? Should the price at which EVN is willing to buy electricity depend on long-term fuel costs?
8. Should EVN follow EGAT and negotiate separate charges for capital and interest from IPP's and then an additional charge for the cost of fuel? How would this be monitored to avoid overcharging for the fuel price?
9. What price structure would allow a price increase with the least amount of political resistance? Should there be a subsidized "lifeline" rate for households that use small amounts of electricity, but higher charges for heavier residential users? Should industrial electricity cost more or less than residential?