WORLD BANK GROUP
Supported by ESMAP
Energy Sector Management Assistance Program

2017/75

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A KNOWLEDGE NOTE SERIES FOR THE ENERGY & EXTRACTIVES GLOBAL PRACTICE

THE BOTTOM LINE

The ability of pumped storage hydroelectric power (PSP) to supply large amounts of electricity at a moment's notice provides a strong complement to the natural variability of wind and solar generation, potentially easing the integration of renewables into Vietnam's burgeoning power system. But the availability of relatively inexpensive off-peak generation for pumping is a central part of the economics of PSP. In today's Vietnam, cheap off-peak power may be hard to come by.


Franz Gerner is the World Bank's energy sector coordinator for Vietnam and Lao PDR.


Debabrata Chattopadhyay is a senior energy specialist in the World Bank's Energy and Extractives Global Practice.


Morgan Bazilian is a lead energy specialist in the same practice.


Ky Hong Tran is a senior energy specialist in the World Bank's Hanoi office.

Is Pumped Storage Hydroelectric Power Right for Vietnam?

What is the best way to meet peak demand in Vietnam's growing power system?

For years, it has seemed as if pumped storage hydroelectric power might be the answer

The development of pumped storage hydroelectric power (PSP) has been under discussion in Vietnam for at least 15 years, spurred by sharp increases in peak demand for power and the wide gap between off-peak demand and the evening peak. In 2005 the Tokyo Electricity Power Company (TEPCO) produced a technical study of PSP and its potential for generating peaking power. Subsequently, Electricity of Vietnam (EVN) and private companies considered several PSP projects.

Selecting PSP projects is difficult. Building and fitting out basins of sufficient size and vertical drop typically costs at least $1,000 per kilowatt (kW) of capacity. And pumping water often requires up to 25 percent of off-peak generation. Other factors must also be considered. For example, the length and capacity of the transmission network between Vietnam's major load and generation centers (in the North and South regions of the country) may limit the potential of PSP to support peak demand in the South.

EVN selected the 1.2 GW Bac Ai in the South as Vietnam's first PSP project. Currently in the technical design phase, it is expected to begin full-scale operation around 2030. At least seven other PSP projects have been considered over the last decade. Some are the subject of feasibility studies; others are being considered under the ongoing revision of Vietnam's power development plan (PDP 7.3, approved in April 2016).

A thorough analysis of the future role of PSP in Vietnam's power mix requires consideration of the likely evolution of the balance between supply and demand, the variability of demand, the nature and timetables of other planned projects, and assumptions about the cost of fuel, among other factors. The analysis must take into account daily load patterns to assess the need for peaking support and whether that need is best met through PSP or other alternatives, such as combined-cycle gas turbine (CCGT) and hydropower plants, or imported power from the Lao People's Democratic Republic.

Given the complexity and importance of proper planning for PSP, the World Bank commissioned Lahmeyer International and the Vietnam Institute of Energy to analyze Vietnam's PSP development strategy in detail. The earlier prefeasibility studies, which underpin PDP 7.3, had presented simplified comparisons of investment costs, technology, and system characteristics to undertake an initial exploration of the potential of PSP in Vietnam.

The central questions examined in the study summarized here (Lahmeyer International and Vietnam Institute of Energy 2016) are whether the potential benefits of PSP outweigh its costs and if so, when, where, and how many megawatts should be introduced into the system and what technology should be adopted. It presents a detailed analysis of the economic storage potential in the northern and southern power networks and shows how the best-fit PSP candidate projects match this potential. Like the earlier studies, it supports the economic viability of PSP in Vietnam but under more conservative conditions. For example, the PDP contemplates commencing operations in 2023, whereas our more recent study recommends doing so only in 2027.

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Where does Vietnam's power sector stand today?

Rapid economic growth has multiplied demand for electricity

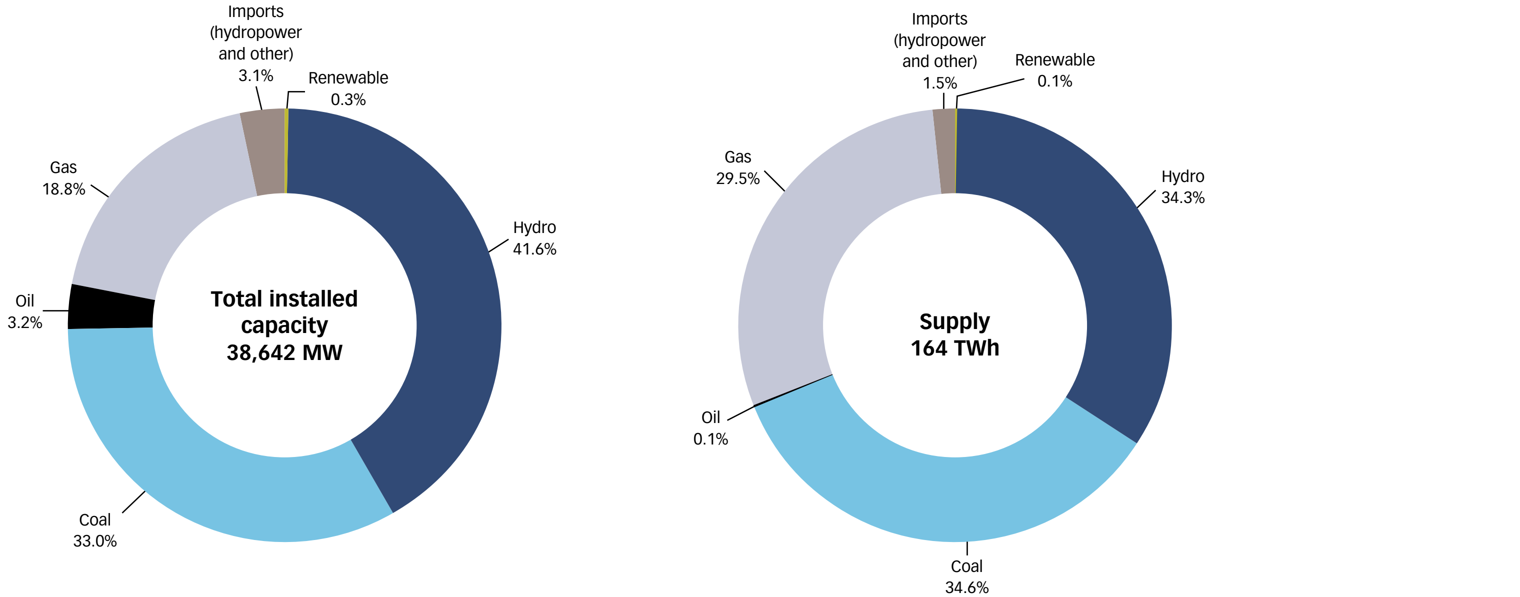
Coming on top of the frenetic growth between 1995 and 2005 (peak demand rose by 13 percent annually), the 10.7 percent average annual growth in electricity consumption between 2010 and 2015 brought annual electricity generation to approximately 164 terawatt hours (TWh) and peak demand (load) to nearly 26.2 gigawatts (GW) (including transmission and distribution losses and on-site plant consumption).

Hydropower generators account for almost 42 percent of Vietnam's installed capacity in 2014, and coal for another third (figure 1). Thermal generation (which accounts for most the rest of the country's generation) runs primarily on domestic coal (about 33 percent of total thermal power, concentrated in the North) and natural gas (about 19 percent of total, concentrated in the South and the Center, of which about one-third is OCGT and two-thirds CCGT). Oil plays a minor role in the generation mix (about 3 percent of the total). The capacity mix has been relatively stable over the last years.

In the fast-growing North, power is provided by hydropower plants linked to reservoirs in the Red River system and coal-fired power plants running on indigenous coal.

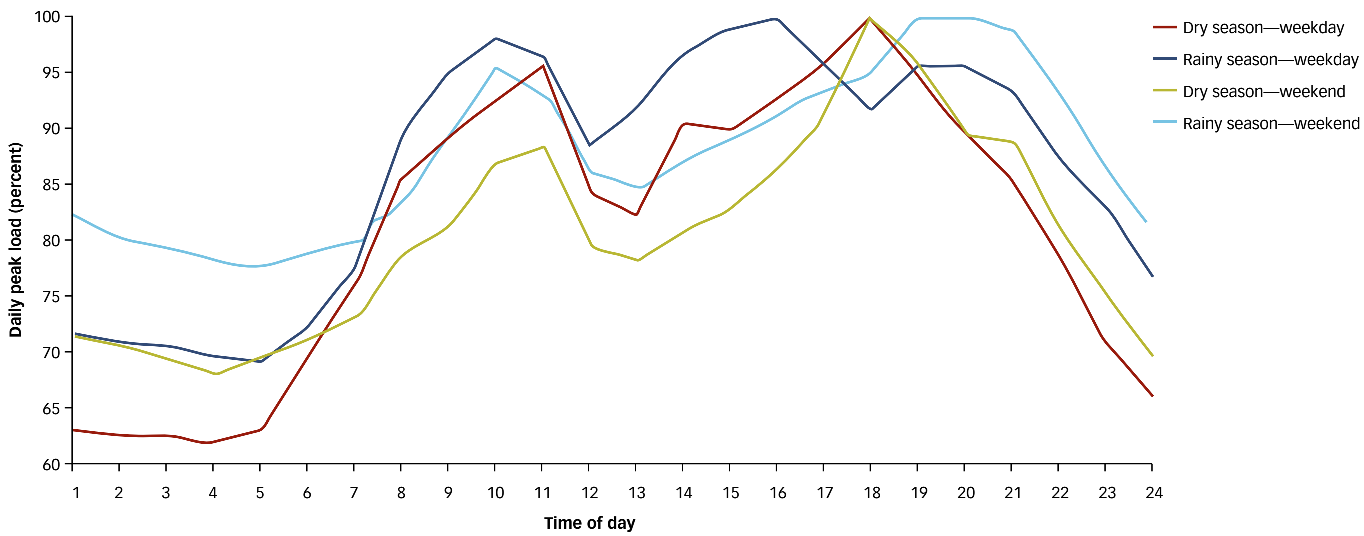
The Center region has the smallest population and the lowest electricity demand. Hydropower plants supply almost all of the region's electricity. In the South, numerous natural gas power plants located along the coast consume gas from offshore gas deposits. The largest gas power complex, located in Cà Mau, consists of two combined-cycle gas turbine (CCGT) configurations with a total installed capacity of 1,500 MW. Gas-fired plants supplied more than three-fourths of the power generated in the South in 2014.

Figure 1. Composition of installed capacity and supply of electricity in Vietnam, 2014



Source: Vietnam Institute of Energy 2016.

Figure 2. Normalized daily load profiles of electricity consumption in Vietnam



Source: Vietnam Institute of Energy 2016.

Since 2010 the most rapid increases in demand for electricity have come from the Center and the North, where growth rates have averaged more than 11 percent a year. The power network of the more-developed South still remains the country's largest, however, with peak demand exceeding 12 GW in 2015.

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Vietnam's capacity reserve margin (the difference between installed capacity and average demand) is about 34 percent. However, there is a big difference between the reserve margin in the North (more than 40 percent) and the tight situation in the South. This large surplus, coupled with the significant share of hydropower, mean that the thermal contribution to peak demand (and thus variability in generation costs) is relatively small, except during the dry season, when hydropower supplies are reduced.

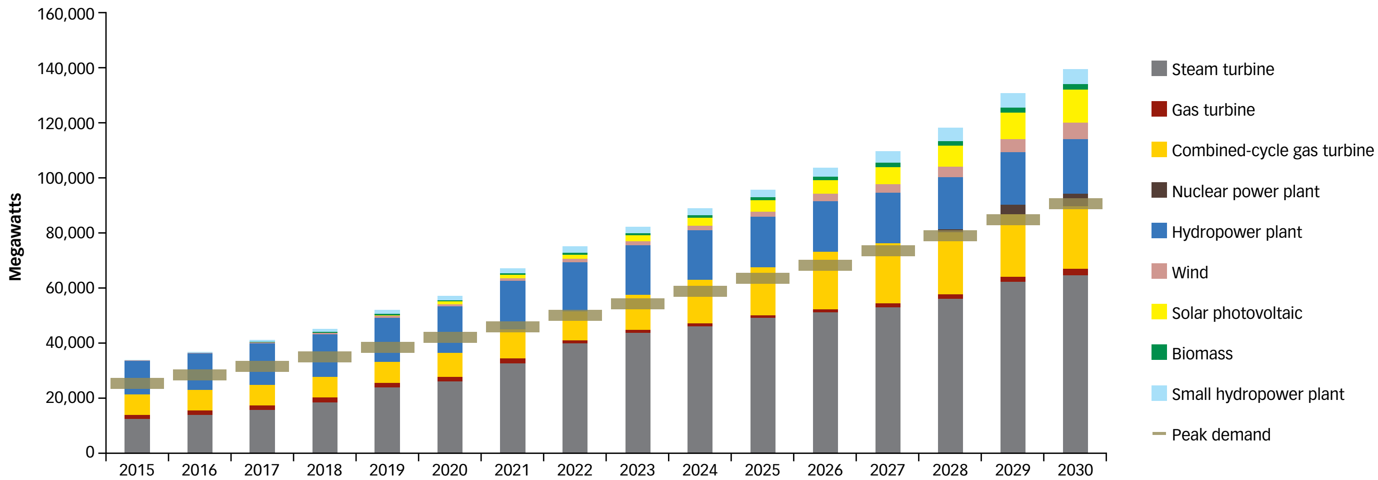
The capacity of the two 500 kV overhead transmission lines connecting the North and Center regions is about 1,800 MW. The lines connecting the Center and South regions comprise four 500 kV and three 220 kV overhead transmission lines with a combined capacity of 3,450 MW.

The system experiences a net positive load flow from the North to the Center and from the Center to the South throughout the year. The direction is reversed during the dry season, when electricity generated by gas and coal power plants in the Center and South is transmitted to the North. For several hours each day during the dry season, the high-voltage transmission system is operated close to its capacity limits.

Vietnam has cross-border connections with Cambodia, China, the Lao People's Democratic Republic.[1] Power exchanges (net

[1] Vietnam and its neighbors also exchange power through several medium- and low-voltage local networks.

Figure 3. Projected expansion of electrical power capacity in Vietnam, by type, 2015–30



Demand for electricity in Vietnam through 2030 is projected to grow at an average annual rate of 8.9 percent a year.2 The increases in generating capacity that have been planned to meet demand are based largely on new power plants burning coal imported from China, Australia, Russia, and Indonesia.3 If realized, the plans will quadruple coal-fired capacity to more than 60 GW, accounting for more than 40 percent of national generation capacity by 2030. … Capacity from renewables is expected to reach 20 GW by 2030.

imports) amount to just 2 percent of national power generation. Vietnam's North is connected with China through 220/110 kilovolt (kV) transmission lines. In 2014 the country imported 2 TWh of electricity from China and exported 885 GWh to Cambodia.

How is the balance of demand and supply expected to evolve?

To meet growing demand, massive increases in generating capacity are planned over the next 15 years

Demand for electricity in Vietnam through 2030 is projected to grow at an average annual rate of 8.9 percent a year.[2] The increases in generating capacity that have been planned to meet demand are based largely on new power plants burning coal imported from China, Australia, Russia, and Indonesia.[3] If realized, the plans will quadruple coal-fired capacity to more than 60 GW, accounting for more than 40 percent of national generation capacity by 2030 (figure 3). Over the same period, the share of hydropower in total capacity will drop to 22 percent, as its potential is nearly fully exploited already. Open- and combined-cycle gas turbines will contribute 20 percent of the system's capacity. Four nuclear power plants (with total capacity of 1.1–1.2 GW) were scheduled to be built at Phuoc Dinh and Vinh Hai, in the South from 2028 onwards. Those plans have recently been cancelled by the Vietnamese government owing to costs and safety concerns. The cancellation will increase the pressure to deliver other thermal assets for baseload generation.

Capacity from renewables is expected to reach 20 GW by 2030. The Center and South are expected to see the fastest growth in capacity fueled by renewable energy, with annual rates averaging

2 This forecast from Vietnam's current power system development plan (PDP 7, April 2016) is grounded in electricity sales, to which technical losses in distribution, transmission, and auxiliary consumption of power plants were added to derive the total required generation.

3 Annual growth in generation capacity is expected to average 11.2 percent in the South, 10.4 percent in the Center, and 7.3 percent in the North.

Table 1. Main features of five planned or prospective pumped storage hydroelectric power projects

Name		Bac Ai	Don Duong	Ninh Son	Moc Chau	Dong Phu Yen (East)
Location (province, region)		Ninh Thuan, South	Lam Dong, South	Lam Dong, South	Son La, North	Son La, North
Installed capacity (MW)		1,200	1,200	1,200	900	1,200/2,100[a]
Status		Technical design review	Feasibility study	Feasibility study	Prefeasibility study	Considered as potential
Year of entry into operation	Feasibility or prefeasibility study	Unit 1: First quarter 2026 Full: 2029	2026	2026–30	2024–26	—
	PDP 7.3 (base)	Unit 1: 2023 Full: 2029	2030	Project not mentioned	Project not mentioned	300 MW in 2028
Investment cost (millions of U.S. dollars)		980 (per feasibility study)	1,399 (per updated feasibility study)	1,023 (per feasibility study)	505 (per prefeasibility study)	1,222 (per Moc Chau prefeasibility study)
Investment rate (U.S. dollars/kW)		817	1,166	853	560	580

Note: Investment costs and rates refer to issue dates of studies. PDP = power development plan; — = not available.

a. The options for the Dong Phu Yen (East) project are to add from four to seven 300-MW units.

25 percent between 2020 and 2030. No formal plan for renewable energy expansion has been published, but the broad mix announced in PDP 7 is about 60 percent solar PV, 30 percent wind, and 10 percent biomass.

The interconnections between the power networks in Vietnam's three regions will be reinforced by the addition of two 500 kV lines between the North and the Center, raising transmission capacity to 3.6 GW after 2020, and two 500 kV lines between the Center and the South, raising capacity to 6.5 GW after 2023.

With improvements in the transmission network, imports of electricity from Lao PDR will increase substantially. The governments of Lao PDR and Vietnam have recently signed a memorandum of understanding under which Vietnam will import 1 GW of hydropower-generated electricity from southern Lao PDR into central and southern Vietnam by 2020. The level of imports through the interconnection will rise to 3 GW by 2025 and 5 GW by 2030.

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How far has PSP planning progressed in Vietnam?

This study analyzed the technical merits, cost, location, and connectivity of five proposed pumped storage projects

Under the original government plan, PSP development is to begin in 2023 with the first two blocks of the Bac Ai project, now in the technical design phase. Development in the North is then slated to continue with the commissioning of Dong Phu Yen (East) between 2028 and 2030. Development of Don Duong, in the South, is set to begin in 2030. Under the plan, PSP projects will reach a total capacity of 2,400 MW in 2030 (1,200 MW in the North and 1,200 MW in the South).[4]

[4] After the Bac Ai PSP was approved, EVN hired consultants to prepare feasibility studies for three other potential projects in the South: Don Duong, Ninh Son, and Ham Thuan Bac. It also requested a second study to rank these PSP projects. That study was conducted by Japan's electric power development company (J-Power) and Power Engineering Consulting Company (PECC). The final report was approved by the Vietnamese government in 2012. Several sites in the North have been considered at various times. They have not yet been ranked or even subjected to full feasibility studies, although Vietnam's Ministry of Industry and Trade intends to commission a ranking study similar to that conducted for sites in the South.

The chief benefits of PSP are the avoided or delayed costs of building, operating, and maintaining the thermal power plants that would otherwise be needed to provide peak power and reserve capacity.

Over the years, EVN and private companies have considered eight PSP projects. Five of them (table 1) were analyzed in the report summarized here; the others were not analyzed because essential information on them was not available.

For the analysis, data were grouped into four categories: technical, cost, site, and connections. The indicators for most criteria were taken as numerical or descriptive (qualitative) parameters from a 2004 study by the Japan International Cooperation Agency.[5]

To arrive at comparable project cost estimates, we converted all cost information to a common currency, referencing it to a common date (January 1, 2017), and drew up comparable bills of quantities for all projects by establishing common unit rates for comparable civil engineering activities and adjusting the bills of quantities for general items and cost surcharges applied at the same level.

Formulas were devised to compute scores for numerical indicators; assessment classes were used for descriptive indicators. Most scores ranged from 0 to 100, but for some criteria the minimum score was set at greater than 0. The combined score for each of the four data categories was derived by adding the weighted scores of all indicators, using the following weights: technical: 30; costing: 30; site conditions: 24; and connections: 16. Other weightings were used to test for sensitivities. A project's combined overall score was determined in a manner comparable to that used to compute the category scores.

The indicator-based evaluation procedure provided robust results for the overall appraisal of the projects and their costs. The sensitivity of the assessments was tested by modifying weighting factors.

Moc Chau (North) earned the highest score; three projects in the South—Bac Ai, Don Duong, and Ninh Son—ranked close behind (table 2). Dong Phu Yen (North) received the lowest score.

The quality and quantity of information on the projects' social and environmental impact varies widely, making assessment difficult, if not impossible. However, the risks and likely adverse impacts of planned sites appear minor to moderate—and susceptible to mitigation.

5 JICA, Master Plan Study on Pumped Storage Power Project and Optimization for Peaking Power Generation, 2004. http://open_jicareport.jica.go.jp/643/643/643_123_11761806.html. Technical parameters: installed capacity, storage capacity, gross head, ratio of head to waterway length, and cycle efficiency; cost parameters: investment costs and costs per kilowatt of installed capacity; site parameters: topography and geology, access, and upper basin catchment area; connection parameters: distance to water supply sources, length of existing access roads, and length of transmission line network.

Table 2. Investment costs and assessment scores of five planned or prospective pumped storage hydroelectric power projects

Project	Investment cost (millions of dollars)	Total score (under base scenario)
Moc Chau	803 (884[a])	81.9
Bac Ai	1,275	81.7
Don Duong	1,256	79.9
Ninh Son	1,247	78.5
Dong Phu Yen[b]	1,346	72.5

Note: For Moc Chau, a new cost estimate will have to be obtained from a consolidated bill of quantities. Bac Ai should be reappraised in combination with an irrigation project planned in the ultimate vicinity.

a. Sensitivity case assuming 10 percent escalatation of investment costs for Dong Phu Yen.

b. Assumed to have 1,200 MW installed capacity.

Feasibility aside, how does PSP fit into Vietnam's power future?

To gauge PSP's economic potential, the study considered several configurations in the North and South

The benefits of PSP are calculated as the difference in total system-wide costs with or without PSP.[6]

The chief benefits are the avoided or delayed costs of building, operating, and maintaining the thermal power plants that would otherwise be needed to provide peak power and reserve capacity. The costs, of course, are the capital and operating expenses of generating PSP and integrating it into the transmission system. For capital costs, the benefits for specific years are annualized in the analysis that follows.

The analysis was done in two steps. The first simulates the entire system for 2025–30, assuming various PSP generation capacities ranging from 0 to 2,400 MW and various reservoir sizes, measured in terms of the full-load hours (FLHs) of demand that they can

6 The benchmark plan is PDP 7.3 without the Bac Ai PSP plant (so that the base case includes no PSP projects). Because the exclusion of Bac Ai might lead to peaking capacity shortfalls in the model, the study substituted generic gas turbines for the PSP that Bac Ai is projected to provide.

The total storage potential of the five candidate projects and the contribution of the two top-ranked projects are analyzed under two scenarios. The robustness of PSP's contribution is then tested under three variants of the base scenario (see figure).

Table 3. Assumptions of scenario analysis

Item	Available firm capacity	Regional availability of firm capacity	Annual percentage increase in demand
Scenario			
Base case	Reference	Reference	8.9
Low-demand	Lower than base case (about 11 GW)	Higher than base case in Center (2025) Higher than base case in South (2030)	8.1
Variants of base-case scenario			
Two-year delay	Lower than base case (about 11–14 GW)	Same as base case	8.9
No nuclear plants	Same as base case	Lower than base case in South (about 4.8 GW)	8.9
Interconnection with Lao PDR	Higher than base case (about 2.7 GW)	Higher than base case in Center	8.9

meet (from 2 to 12). The storage configurations were simulated separately in the networks of the North and the South. For the cost and efficiency of potential storage, the weighted average of the PSP candidate projects discussed above was used. The simulations yield the overall storage potential of the system.

The second step simulates implementation of the two top-ranked projects (Bac Ai and Moc Chau), to gauge the extent to which they achieve the overall potential of PSP. This step assesses the effect of the location and timing of individual PSP projects.

The quantitative analysis uses the Lahmeyer International Power System Operational Planning (LIPS-OP) model, which solves a mathematical optimization problem that minimizes system-wide operational costs (such as fuel and variable operation costs and start-up costs). LIPS-OP simulates the commitment and dispatch of the operational units of the power system simultaneously for each hour of the planning horizon, subject to various technical and economic constraints (fulfillment of load and reserve requirements for the system as a whole; technical capacity and ramping limits for individual units).

Although LIPS-OP is well suited to analyzing the operational implications of introducing new generation assets to a system, it does not account explicitly for investment decisions. Changes in the capacity mix of a system must be exogenously specified. New thermal units (that is, units to be commissioned in the year to which the analysis applies or delayed from earlier years) are assumed to be "avoided" in a specific year if PSP causes their capacity factor to drop by 40 percent or more compared with the benchmark case, such that investors would likely be dissuaded from investing in them.

The total storage potential of the five candidate projects and the contribution of the two top-ranked projects are analyzed under two scenarios. The robustness of PSP's contribution is then tested under three variants of the base scenario. The scenarios and sensitivities differ along the following key dimensions: (a) available firm capacity (thermal, hydropower, and power imports through interconnections); (b) regional availability of firm capacity; and (c) demand.

The *base-case scenario* reflects system development as specified in the reference scenario of PDP 7.3. Demand is assumed to grow at an average annual rate of 8.9 percent.[7] The *low-demand scenario* assumes growth of 8.1 percent a year. In line with this reduction, the low-demand scenario assumes that less new generating capacity (including less-variable renewable and hydropower capacity) is commissioned. Beginning in 2025, annual installations lag the base case significantly. By 2030, 10.8 GW less thermal capacity is added, an amount equivalent to 12 thermal power generation units. The total difference in capacity between the two scenarios in

[7] In order to capture the full effects of integrating PSP into the power system, the base capacity expansion scenario used in this study assumes no PSP. In fact, PDP 7.3 includes the Bac Ai PSP, but in our analysis, as previously noted, we wish to create a "No PSP" benchmark; to do that, Bac Ai is replaced by generic 250 MW gas turbine units assumed to come online as needed through 2030.

PSP projects have only limited potential to store water to meet full loads through 2030. In both scenarios evaluated (base and low-demand), economically viable storage potential does not exceed 1,500 MW. Given the sizes of PSP candidate projects, this potential could be met by one PSP plant built in the North or South, or by one in each network.

2030, including hydropower and renewable energy, is 13.6 GW. The basic assumptions of the two scenarios—and of three variants of the base-case scenario—are summarized in table 3.

In the low-demand scenario, capacity in the South is more than 7.7 GW lower than in the base case. Capacity shortages in that region's network produce sustained demand for energy transfer through existing interconnections. Because the drastic shortages in supply materialize only toward the end of the study period, the net capacity reserve margin drops from 21 percent in 2025 to –17 percent in 2030, at which point a significant amount of unserved demand (load shedding) may be expected.

The study tests three variants of the base scenario.

The first delays the commissioning of new capacity by two years. In contrast to the low-demand scenario, this variant does not cut demand or eliminate the commissioning of renewable energy or hydropower capacities. Variant 1 produces a shortage of 8–11 GW of thermal generation capacity for each year considered. The net capacity reserve margin (including additional renewable energy reserve requirements) drops to 12 percent in 2025 and to –5 percent 2030.

The second variant of the base case tests the effects of building no new nuclear plants. It introduces a deficit of thermal generation capacity of 1.2 GW in 2028 and 4.8 GW in 2030, corresponding to 15 percent and 44 percent of the capacity shortage in variant 1. The net capacity reserve margin (including additional renewable energy reserve requirements) drops to 9 percent in 2025 and –1 percent in 2030, as renewable energy and demand strain the required reserve.

The third variant tests the effects of current plans to enhance power transfers with Lao PDR over a high-voltage direct current interconnection capable of carrying up to 2,700 MW to the network in Vietnam's Center region. As this variant adds firm capacity to the system, the net capacity reserve margin (including additional renewable energy reserve requirements) stands at 19 percent in 2025 and 1 percent in 2030.

What does the analysis suggest?

The economic potential of PSP plants appears limited

Through 2030, the economic potential for PSP in the base case is just 600 MW and 4 FLHs of storage capacity in the North and 900 MW and 8 FLHs in the South. Storage development in the North would start with 300 MW in 2026 and be scaled up to 600 MW in 2027. In the South, PSP development would start with 300 MW in 2027 and be scaled up to 900 MW in 2028.

More than 90 percent of the accrued benefits of PSP would be derived from delayed investments in thermal power plants. Realizing the PSP potential in the North would defer 1,500 MW of CCGT units and 500 MW of OCGT units. The effect would be even more pronounced in the South, where a total of 3,000 MW would be deferred.

Step 1 of the simulation of the base-case scenario suggests that the weighted average capacity factors of all thermal generation assets would rise by 3.3–6.7 percentage points. The resulting effects on system-wide generation costs would yield only minor benefits compared with the benefits derived from avoided investments.

Under the low-demand scenario, the greatest net benefits of PSP would be reaped in the North, with storage capacity of 300 MW (4 FLHs) by 2030, and in the South, with storage capacity of up to 1,200 MW (8 FLHs). Timing is essential. In the North, PSP does not induce positive net benefits before 2030. In the South, the greatest net benefits are achieved when PSP development starts in 2027, with 600 MW (8 FLHs).

As under the base-case scenario, deferring the construction of new thermal capacity accounts for the bulk of total net benefits. A total of 1,420 MW of CCGT units and 250 MW of OCGT units could be avoided by 2030 if PSP capacity were available to serve the network in the South. Only marginal benefits could be expected from a PSP serving the network in the North.

In summary, PSP projects have only limited potential to store water to meet full loads through 2030. In both scenarios evaluated (base and low-demand), economically viable storage potential does not exceed 1,500 MW. Given the sizes of PSP candidate projects, this potential could be met by one PSP plant built in the North or South, or by one in each network.

The chief purpose of PSP in the Vietnamese context would be to provide reserve capacity. In the base-case scenario, only about 40 percent of Bac Ai's capacity would be dedicated to base-load power generation, and actual utilization rates would be even lower, as only peak demand is effectively targeted.

To determine the optimum PSP deployment, the study simulated the operation of the Moc Chau PSP plant in the North and the Bac Ai plant in the South, as well as a combination of both, for 2026–30. It estimated both operational benefits and benefits from deferral of the construction of new thermal plant capacity.

Table 4 summarizes the main results of the simulation of Bac Ai, based on opportunity costs of unserved demand of $144/MWh.[8] It shows both project-specific results and the wider effects on the power generation system as a whole.

Under the base scenario, and at the assumed opportunity costs, the Bac Ai PSP plant would yield a positive net benefit of $215 million in 2028. Under the low-demand scenario and all three variants of the base scenario, it would yield negative net benefits (though it would still be the best among the five projects analyzed).

The chief purpose of PSP in the Vietnamese context would be to provide reserve capacity. In the base-case scenario, only about 40 percent of Bac Ai's capacity would be dedicated to base-load power generation, and actual utilization rates would be even lower, as only peak demand is effectively targeted. The low-demand scenario and variant 1 (the two-year delay in commissioning new thermal capacity) lead to similar distributions.

PSP's role in providing reserves would be even more pronounced under variant 3 (interconnection with Lao PDR). In this case, less than 30 percent of Bac Ai's capacity would be used to generate power to meet base load. A much higher rate of power generation (68 percent) is observed only under variant 2 (no nuclear plants), where PSP would partly fill the generating gap.

Given the high investment costs of PSP projects and their relatively low utilization rates, the levelized cost of electricity of all PSP candidate projects is well above $0.10/kWh (before the cost of pumping); for Bac Ai it exceeds $0.19/kWh. From an economic point of view, the short-run marginal costs (reimbursed only during hours of operation) are not competitive with the country's average generation costs, which are on the order of $0.045/kWh.

The picture changes only when PSP is compared with the generation cost of peaking units ($0.20–$0.25/kWh).[9]

Under all three variants of the base-case scenario, capacity deferral is lower than under the base scenario and less sustained through 2030. Thus the benefits from avoided or deferred investments in thermal units are not large enough to offset investment in the Bac Ai plant. Although the presence of Bac Ai would enable more efficient use of existing plants, the cost savings are smaller than the investment costs, as shown in table 5 by the changes in thermal power plant capacity factors and the corresponding evolution of average system generation costs.

Largely as a consequence of increasing reserve capacity, PSP can improve system reliability, make regional networks more self-reliant under ordinary conditions, smooth transfers of power and reserves, and permit deferred investments in thermal plants built and operated solely to provide reserve capacity. The extent to which these potential benefits are realized varies depending on the amount of overcapacity in the individual networks, the level of unserved demand, the value (or opportunity cost) of that demand, and the reserves needed to cover the loss of one or more large generation units and renewable energy generators.

Would the Bac Ai PSP plant make Vietnam's generation system more reliable? The answer is revealed by calculating the loss-of-load-probability (LOLP) for each scenario and variant.[10] Under both the base-case and low-demand scenarios, the LOLP could be halved by adding firm capacity in the form of PSP from Bac Ai, but there may be more cost-effective ways of achieving the same improved reliability through demand response, gas turbines to provide peaking power, interconnection with hydropower generators in Lao PDR, or some combination of these. Moreover, when surplus capacity is present (as in variant 3), the reliability benefit from PSP falls significantly.

Particularly in cases where generation and reserve capacity are insufficient (as indicated by system capacity margins close to or below 1—that is, available firm capacity falls below the annual peak demand), unserved demand is considerable toward the end of the study period. Unserved energy was evaluated at an opportunity cost of $144/MWh, which reflects solely the variable cost of back-up generation. But Vietnam's energy productivity profile in 2015 suggests that the opportunity cost of unserved demand for energy is many times

8 Assumes diesel-fired gensets, a fuel price of $2/gallon, and an average efficiency of gensets of 30 percent.

9 The (cost-minimizing) simulation of the Vietnamese system implicitly accounts for pumping cost, the cycle efficiency of PSP, and thus the actual generation cost.

10 LOLP represents the probability or fraction of a given year during which demand cannot be met.

Over the long run, only delayed or avoided investments in thermal plants could be great enough to offset the substantial investment costs of PSP projects. … Under the base-case scenario, the net economic benefits of a PSP plant in the South are about $215 million in 2028, when the bulk of the capacity deferral would occur. Under the low-demand scenario, no positive net economic benefits of PSP could be expected.

Table 4. Projected performance of best plant (Bac Ai) at opportunity cost of unserved demand of $144/MWh, under both scenarios and base-case variants

	Scenario		Variants of base scenario		
	Base	Low demand	Two-year delay	No nuclear plants	Interconnection with Lao PDR
PSP results, Bac Ai plant					
Year of commissioning	2027	n.a.	n.a.	n.a.	n.a.
Capacity (MW and [full load hours])	1,200 [7.7]	1,200 [7.7]	1,200 [7.7]	1,200 [7.7]	1,200 [7.7]
LCOE[a] ($/MWh)	198.8	244.7	198.8	198.8	198.8
Annual supply (GWh)	1,739	2,812	2,305	1,322	2,427
Annual energy share in 2028 (%)	39	34	35	68	28
Annual reserve share in 2028 (%)	61	66	65	32	72
Annual primary reserve potential (GWh)	269	421	174	128	249
Annual secondary reserve potential (GWh)	787	1,434	1,332	294	1,500
System results					
System capacity margin in 2030 without RE (%)	1.2	0.96	1.09	1.15	1.23
Average system generation costs in 2030 without PSP ($/MWh)	45.08	44.29	55.25	45.36	44.91
with PSP	45.05	44.25	55.1	45.32	44.89
Loss-of-load probability in 2030 without PSP (hours)	0.75	10.9	63	6.4	0.78
with PSP	0.33	5.5	62.2	5.2	0.8
Net benefits in 2028 ($ millions)	215	n.a.	n.a.	n.a.	n.a.
Maximum avoided thermal capacity by 2028 (MW)	3,000	960	150	710	710
Avoided fossil-fuel generation by 2028 (GWh)	–517	–600	–556	–580	–516
Avoided unserved demand by 2028 (GWh)	577	549	4	–2	1
Percent change in capacity factors of thermal power plants by 2028 (vs. no PSP)	+3.5	–1.4	+0.2	+4.2	+4.8

Source: Lahmeyer International and Vietnam Institute of Energy (2016).

Note: Opportunity cost of unserved demand for energy assumes diesel-fired gensets, a fuel price of $2/gallon, and an average efficiency of gensets of 30 percent.

n.a. = not applicable (PSP not included in scenario); PSP = pumped storage power; LCOE = levelized cost of energy; RE = renewable energy

a. Assuming energy capacity factor of plant of 9 percent.

If an interconnection to Lao PDR is built, no PSP would yield net benefits. Vietnam and the Lao PDR have signed a memorandum of understanding under which Vietnam intends to import 5 GW of hydropower by 2030. In the presence of such a large and easily regulated source of additional power, PSP would no longer yield benefits from avoided investments in additional thermal generation or fuel costs from operating plants more efficiently.

Table 5. Projected performance of best plant (Moc Chau) at opportunity cost of unserved demand of $1,200/MWh, under variants to base scenario

	Variants of base scenario		
	Two-year delay	No nuclear plants	Interconnection with Lao PDR
PSP results, Moc Chau plant			
Commissioning date	2026	2028	2029
Capacity (MW and [full load hours])	900 [6.9]	900 [6.9]	900 [6.9]
LCOE[a] ($/MWh)	133	133	133
Annual supply (GWh)	2,114	1,988	1,914
Annual energy share in 2028 (%)	18	28	28
Annual reserve share in 2028 (%)	82	72	72
Annual primary reserve potential (GWh)	274	273	271
Annual secondary reserve potential (GWh)	1,452	1,158	1,099
System results			
System capacity margin in 2030 without RE (%)	1.09	1.15	1.23
with RE	0.95	0.95	1.01
Average system generation costs in 2030 without PSP ($/MWh)	55.25	45.36	44.91
with PSP	55.38	45.41	44.95
Loss-of-load probability in 2030 without PSP (hours)	63	6.4	0.78
with PSP	62.4	4.9	0.85
Net benefits in 2028 ($ millions)	336.9	58.1	381.6 (2030)
Maximum avoided thermal capacity by 2028 (MW)	150	710	710
Avoided fossil-fuel generation by 2028 (GWh)	–659	–842	–839.3
Avoided unserved demand by 2028 (GWh)	335	466	467
Percent change in capacity factors of thermal power plants by 2028 (vs. no PSP)	+0.1	+0.1	+1.4
Capacity factor, domestic interconnections, in 2028 (%)	60.8	54.9	57.6

Source: Lahmeyer International and Vietnam Institute of Energy (2016).
Note: Assumes diesel-fired gensets, a fuel price of $2/gallon, and an average efficiency of gensets of 30 percent.
PSP = pumped storage power; LCOE = levelized cost of energy; RE = renewable energy
a. Assuming plant energy capacity factor of 12 percent.

higher. Once the wider impact of outages on the economy is taken into account, the opportunity cost may be closer to $1,200/MWh.[11]

Table 5 presents the results of the analysis at the higher opportunity cost. Because a large share of unserved energy occurs in the North, Moc Chau becomes the PSP project that produces the greatest economic benefit. At the higher opportunity cost, implementing the Moc Chau PSP, by providing reserve capacity, could free up more than 600 GWh of fossil fuel–based generation to meet unserved demand.

But whatever benefits flow from reducing unserved demand, neither Moc Chau or any of the other candidate PSP projects would yield positive net benefits under variant 3: an expanded interconnection with the Lao PDR that would provide three times the capacity of Moc Chau. In the presence of such a large and easily regulated source of additional power, PSP can no longer be justified in terms of avoided investments or fuel costs.

The bottom line?

Only delayed or avoided investments in thermal plants may be great enough to offset the substantial investment costs of PSP projects

Vietnam's PDP 7.3, updated in April 2016, contemplates the construction of several PSP projects before 2030. Development is presently set to begin in 2023, with two blocks of the Bac Ai PSP in the South, and continue in the North, with the development of the Dong Phu Yen (East) project between 2028 and 2030. Development of Don Duong, in the South, would commence in 2030. If all three plants were built, PSP capacity would reach 2,400 MW in 2030 (1,200 MW in the North and 1,200 MW in the South).

Over the long run, only delayed or avoided investments in thermal plants could be great enough to offset the substantial investment costs of PSP projects. (PSP yields only marginal benefits in terms of fuel costs—not enough to offset its investment costs.) Under the base-case scenario, the net economic benefits of a PSP plant in the South are about $215 million in 2028, when the bulk of the capacity deferral would occur. Under the low-demand scenario, no positive net economic benefits of PSP could be expected. Delays in the scheduled commissioning dates of new thermal plants could increase the benefits of PSP, because PSP plants could be used to generate power during hours of peak demand, in addition to their primary role of increasing reserve capacity.

Under reasonable assumptions about Vietnam's likely rate of economic growth and the stability of its energy supplies, the Bac Ai PSP plant would yield positive net benefits—but only if commissioned in 2027, four years later. Only if a significant shortage of energy were expected (a shortage equivalent to 8 GW or more of thermal generation capacity) would a PSP project in the North be viable—and then only if the current level of energy productivity were maintained or increased. If those conditions materialized, then the Moc Chau PSP plant would yield positive benefits by meeting demand that would otherwise go unserved (assuming an opportunity cost of $1,200/MWh, derived from Vietnam's current energy productivity).

If an interconnection to Lao PDR is built, no PSP would yield net benefits. Since the Lahmeyer International study was conducted the governments of Vietnam and the Lao PDR have signed a memorandum of understanding under which Vietnam intends to import 5 GW of hydropower by 2030. In the presence of such a large and easily regulated source of additional power, PSP would no longer yield benefits from avoided investments in additional thermal generation or fuel costs from operating plants more efficiently.

[11] Energy productivity is based on 2015 GDP of $193.6 billion (World Development Indicators Database, accessed September 28, 2016).

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This summary was prepared by a World Bank team consisting of Franz Gerner (task team leader), Debabrata Chattopadhyay, Morgan Bazilian, and Ky Hong Tran. It is based on a study commissioned by the World Bank on behalf of the Ministry of Industry and Trade of the Republic of Vietnam. That study was conducted in 2016 by Lahmeyer International GmbH and the Vietnam Institute of Energy. The lead author of the study report was Lahmeyer's Tim Hoffmann.

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