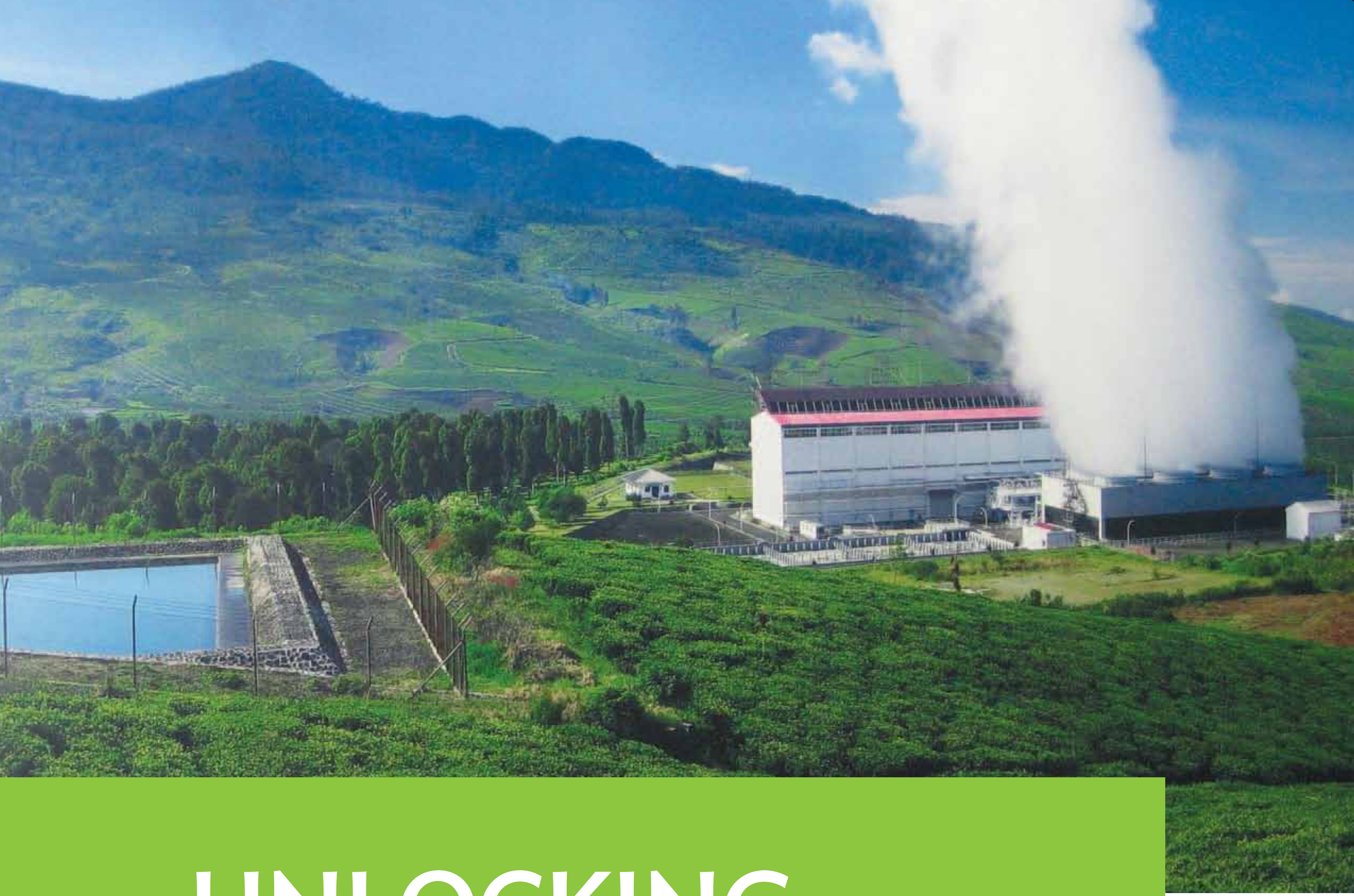

UNLOCKING INDONESIA'S GEOTHERMAL POTENTIAL

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ADB

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Cover photo of Wayang Windu geothermal power plant in West Java, Indonesia by Star Energy.

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Abbreviations

3G	geology, geophysics, and geochemistry
ADB	Asian Development Bank
ARGeo	African Rift Geothermal Development Program
BBP	binary bottoming plant
BPP	back pressure plants
CV	calorific value
CCT	clean coal technologies
CER	Certified Emission Reduction
COD	commercial operation date
CTF	Clean Technology Fund
DSCR	debt service coverage ratio
FIRR	financial internal rate of return
FIT	feed-in tariff
fob	free on board
FTP	Fast Track Program
FTP1	Fast Track Program 1
FTP2	Fast Track Program 2
GDE	Geo Dipa Energi
GDP	gross domestic product
GeoFund	Geothermal Energy Development Program
GHG	greenhouse gas
GSCC	global social cost of carbon
HFO	heavy fuel oil
IEA	International Energy Agency
IFC	International Finance Corporation
IFI	international financial institution (Asian Development Bank, World Bank)
INAGA	Indonesia Geothermal Association
IPP	independent power producer
IUP	Izin Usaha Pertambangan (Mining Business Permit)
JBIC	Japan Bank for International Cooperation

JICA	Japan International Cooperation Agency
LNG	liquefied natural gas
MEMR	Ministry of Energy and Mineral Resources
MFF	multitranche financing facility
MIGA	Multilateral Investment Guarantee Agency
MoF	Ministry of Finance
MSOE	Ministry of State-Owned Enterprises
MUV	manufacture unit value (index)
NPV	net present value
O&M	operation and maintenance
OPEC	Organization of the Petroleum Exporting Countries
PGE	Pertamina Geothermal Energy
PIP	Pusat Investasi Pemerintah (Indonesia Investment Agency)
PLN	PT Perusahaan Listrik Negara (State Electricity Company)
PPA	power purchase agreement
PSO	public service obligation
RUPTL	Rencana Usaha Penyediaan Tenaga Listrik (Electricity Power Supply Business Plan)
SAGS	steam above ground system
SOE	State-Owned Enterprise
WACC	weighted average cost of capital
WEO	World Energy Outlook (of the IEA)
WKP	wilayah kerja pertambangan (geothermal work area)

Currency and Units

All references to "dollars" and "$" refer to United States dollars
Except where noted otherwise, $1 = Rp11,500; 1¢ = Rp115
All references to "tons" refer to the metric ton (of 1,000 kg)

BTU	British thermal unit
GJ	gigajoule
GW	gigawatt
GWh	gigawatt-hour
kJ	kilojoule
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
MWe	megawatt electric
MWh	megawatt-hour

Foreword

Geothermal energy represents one of the key options for Indonesia to achieve a comprehensive approach to national energy development. The rapid increase in fossil-fuel based energy consumption, which is subject to volatility in the world oil market, is the main challenge facing the country's energy supply. At the same time, growing greenhouse gas emissions from the use of fossil fuels imposes costs on the economy and society. Geothermal energy provides one solution to these issues. It is a source of clean, renewable and environmentally friendly energy for power generation. Furthermore, as an indigenous and non-tradable energy source, it will enhance the country's energy security by serving as a natural hedge against the fluctuations of global fossil fuel prices. The Government of Indonesia has recognized the role of geothermal energy and has put major efforts into promoting its development with initiatives such as the Roadmap of Geothermal Development 2012–2025, the National Energy Policy 2014, the issuance of a new geothermal tariff in 2014 and the Geothermal Law No. 21 of 2014. Participation from all stakeholders, public sector as well as private sector, is essential to raise awareness of the role of geothermal power in the national energy strategy.

This publication, "Unlocking Indonesia's Geothermal Potential," provides useful insights to policy makers, investors, geothermal industry practitioners, and all geothermal development stakeholders. The report identifies the main issues that are hindering geothermal power development and reviews geothermal related policies and regulations in Indonesia. Its analyses and recommendations cover key issues of the sector's development such as the geothermal tariff design, improvement in tendering processes, Power Purchase Agreements and price renegotiation, institutional and other financing issues.

I hope that all Indonesia geothermal stakeholders will benefit from the report. I believe that the report provides valuable inputs toward acceleration of the future development of geothermal energy in Indonesia.

Rida Mulyana
Directorate General of New, Renewable Energy and Energy Conservation
Ministry of Energy and Mineral Resources

Acknowledgments

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The authors of this report are Peter Meier, James Burke Randle, and James Vincent Lawless. The report reflects the contributions of Muchsin Qadir (World Bank), Yuki Inoue (consultant, ADB), Maura Lillis (consultant, ADB), Kazim Saeed (consultant, World Bank), Surya Darma (consultant, World Bank), Olivia Tanujaya (World Bank), and Yerri Anullah (legal consultant, World Bank). The team would also like to thank Richard Spencer (World Bank) for his helpful review. Pham Nguyet Anh (World Bank) and Pradeep Tharakan (ADB) directed the study.

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Executive Summary

This joint report of the Asian Development Bank (ADB) and World Bank presents a review of Indonesia's geothermal sector, prepared in the context of a request from the Government of Indonesia's Ministry of Energy and Mineral Resources (MEMR) for assistance with a planned revision. The ministerial regulation for the new geothermal tariff was issued by MEMR in June 2014.

The 2012 feed-in tariff (FIT) was a first attempt to unlock the sector. But this FIT raised as many new questions as it solved, and it is generally agreed that much more needed to be done to consult with stakeholders than had been done before. For this reason, MEMR has engaged extensively with stakeholders in the consultations for a new tariff issuance.

In our view, there are four main areas that need attention and that need to be addressed together. Only concerted and coordinated action in all areas simultaneously will unlock the sector. The underlying problem is really one of capital mobilization for a generating option that is unusually capital intensive: just to achieve an additional 3,000 MW geothermal capacity in the foreseeable future will require $4 billion in equity and $9.5 billion in debt finance (assuming $4,500/kW total cost, and 30% equity). The problem of mobilizing equity is primarily one of the adequacy of tariffs to enable the up-front equity needed for exploration—much more costly than in other countries where much of the up-front exploration effort was funded as a pure public good.

A key problem for raising debt finance is that even the international financial institutions (IFIs) (ADB, International Finance Corporation, World Bank/International Bank for Reconstruction and Development [IBRD]) are reluctant to fund up-front exploration and typically will provide financing only once 50% or more of the steam resource is proven. To date, targets for geothermal achievement have not been set with full knowledge of the incremental costs of achieving them.

Clarifying the Role of the State

There are two major issues to be faced. The first is how best to resolve the competing interests of the main state entities involved in the sector: the Ministry of Finance (MoF) is concerned about the increasing size of the public service obligation (PSO) to *PT Perusahaan Listrik Negara* (PLN), Indonesia's state-owned electricity company, which it regards as increasingly unsustainable. Reducing the magnitude of the PLN subsidy is its greatest concern in the power sector, which obviously conflicts with the probable incremental costs of geothermal energy and the need to increase the subsidy to achieve the geothermal targets. The Ministry of State-Owned Enterprise (MSOE) has as its main objective the satisfactory commercial performance of its enterprises, which include both Pertamina and PLN. Consequently the Pertamina Board of Directors (and in particular the director primarily responsible for investment planning) are reluctant to allocate equity capital to PT Pertamina Geothermal Energy (PGE) when compared to the much higher returns available in Pertamina's oil and gas plays. While an objective comparison of the resource risk in oil and gas versus geothermal energy might well conclude the risks are higher in oil and gas, these are more than offset by the very much higher returns. In short, the regulated returns in the electricity sector are not commensurate with the risks of the geothermal business—with the result that PGE faces a continuous battle for resources from its parent company. Finally, MEMR sees its role as the promoter of geothermal energy, and is responsible for supervising the sector's development, including responsibility for implementing the Geothermal Law, and for tariff setting. It is the entity primarily responsible for promoting geothermal energy, but whether its goals can actually be met—how to mobilize the equity and debt necessary to achieve successful project development—has been left to others.

These differences in objectives have not been helped by poor communication between MEMR and MoF in the matter of tariffs in the past. Indeed, basic principles of stakeholder consultation were ignored in the issuance of the 2012 FIT. Fortunately, that lesson has been learned by MEMR, and its efforts to consult with stakeholders in its new tariff issuance process has been exemplary.

The second issue is to clarify precisely the roles that each of the state entities currently active in geothermal should play. Pertamina still owns many (legacy) concessions that remain undeveloped, yet Pertamina is still bidding for new projects. Indeed, PGE was created by Pertamina to develop geothermal energy projects, but as noted, is not provided with the equity funding necessary to successfully develop the projects assigned to it. PT Geo Dipa Energi (GDE) was created in 2002 to develop some specific projects, but it too was not funded with the adequate equity. PLN Geothermal has experience with the power generation part of geothermal energy projects, but its role in developing particularly the smaller geothermal energy projects in the eastern islands remains unclear. The management of the Geothermal Fund has been given to an entity of the MOF—but it lacks the necessary technical experience.

In this respect, we support the efforts of PGE to enter into partnerships with qualified private developers as a way to bring in additional equity. However, this strategy will be successful only if the previously negotiated prices for PGE's projects, set many years ago, and prior to the recent rises in drilling costs, can be satisfactorily renegotiated.

Tendering

Competitive selection of private sector developers is mandated by the Geothermal Law. However, notwithstanding the good intentions of the law in devolving the tender process to the provinces, there is widespread concern that the tender process needs improvement. Particularly in the eastern islands, the tender process has resulted in winning bids at prices that are so low that few believe they can be implemented. In addition, many entities have won bids with insufficient technical and financial capacity. The alleged deficiencies are many, including lack of technical capacity of the tender committee (resulting in poor prequalification screening), bid bonds that are too small (so unqualified bidders are not excluded), and performance bond requirements that are not imposed.

The principles that should apply to tendering have been well established in International Practice, as exemplified by the procurement rules of ADB and the World Bank (Section 7). These should be followed for Indonesia geothermal tenders. In particular, there should be a requirement to post a significant bid bond (stipulated as a percentage of the total project cost rather than just a percentage of the first year exploration program), of no less than $10 million. The winning bidder's bid bond should then be converted into a performance bond that can be released upon evidence of exploration drilling.

International experience demonstrates that the most effective way of improving the quality of a tender process for exploiting a natural resource is to improve the quality of resource information made available to bidders. No concession area—*wilayah kerja pertambangan* (geothermal work area)—should be put to tender without a complete and independently certified package of geology, geophysics, and geochemistry (3Gs). In the ideal case, and particularly in the eastern islands where the larger developers have little interest in developing smaller projects, subsurface information should also be provided, ideally with a minimum of three wells, with information presented to the standards of an internally accepted resource code (see Appendix 1), and again, independently certified. Proposals on how such a pre-tender exploration program should be organized, and the role of the Geothermal Fund, are presented in Section 9 of the report.

The value of up-front de-risking as a public good is widely acknowledged in international geothermal practice. Section 8 of the report presents an analysis of the impact of such de-risking on the tariff.

We argue that if this up-front de-risking were provided by the Geothermal Fund, its costs should be recovered from developers at the time of financial closure, at which point the weighted average cost of capital is much less than that of privately provided risk equity in the early stages of project development. Many of the principles that should govern an exploration program using public funds have been presented before (by ADB, the Japan Bank for International Cooperation [JBIC], and others). Here we provide further quantitative argument for doing so.

In the long term, Indonesia should establish a technically qualified, central tender entity to conduct tenders on behalf of local governments. During the preparation of this report, Indonesia's House of Representative passed the Bill on Geothermal Energy as a revision to the previous Geothermal Law No. 27 of 2003. One of the major changes in the new bill is that the geothermal concession tender and issuance of geothermal license for power development will be carried out by the central government (MEMR). The new bill assures the interests of the local governments through a production bonus sharing when the power plant starts operation commercially as well as applicable local taxes. The key point for such a centralized process is institutional longevity, which is essential to equitably regulate a process where project gestation times can be 8–10 years. The central government will likely require significant technical assistance, but the international finance institutions (IFIs) and bilateral donors would certainly be interested in providing this. The question of how the size of the production bonus will be determined by MEMR, and the mechanism for its recovery, will also require extensive stakeholder consultation.

Tariff Reform

We recommend a return to the prior system of tender-determined tariffs. The 2012 FIT system proposed in 2012 has the defect that with fixed prices, developers would then be selected on non-price qualifications only (i.e., a "beauty contest"), which many developers oppose on grounds that subjective evaluations are unreliable and unpredictable. If the improvements we recommend to improve the tender process are adopted, then the system of competitively determined bid prices can remain. However, the old ceiling price of 9.7 US¢/kWh needs revision. Indeed, any ceiling price set for a tender bid today should not be based on what is an appropriate ceiling today, but what is an appropriate ceiling for the date of commercial operation, which may be 7–9 years in the future.

We recommend that tariff setting be seen not so much as a one-time event, but as a process. This again is proven by international best practice for the regulation of renewable energy tariffs: most countries have a system of regular review of tariffs, based on a published methodology and stakeholder consultation. These principles are elaborated in Sections 2 and 3.

Our recommendation for ceiling prices is provided in Section 4: they should be set on the basis of the benefits of geothermal energy. Projects in which competitively bid costs exceed these benefits should not proceed. We recommend a return to the avoided cost approach proposed by Castlerock in 2010, but with a more transparent process to translate these principles into a formal methodology for forecasting a reasonable base price for projects whose commercial operation is 7–9 years away.

The benefits to Indonesia of increased geothermal energy are many. The first is the avoided costs of PLN. But PLN's avoided costs are very different in the case of the big systems on Java and Sumatra where the alternative is state-of-the-art coal (with high efficiency, state-of-the-art pollution controls), than on the eastern islands, where the alternative is the diesel or small coal systems, sometimes less than 25 MW in size, but whose unit cost may be double that of an ultra-supercritical coal project on Java. The second set of benefits relates to local regional economic development. It is one of the main goals of government policy to encourage economic development in the eastern islands, for which geothermal development provides an urgently needed contribution.

The third set of benefits relate to the avoided externality costs of thermal generation, notably that of avoided greenhouse gas (GHG) emissions. But this raises difficult questions of what value the Government of Indonesia should place on avoided GHG emissions and the extent to which that value may be higher than the current price in global carbon markets (an issue raised in the stakeholder consultations). This highlights the need for agreement between the three ministries noted above, on the incremental costs that Indonesia should be willing to pay.

In June 2014, MEMR issued a new geothermal tariff regulation (MEMR Regulation No. 17 of 2014) based on the tariff study recommended by the World Bank/ADB. The discussion on the new tariff is presented in Appendix 7.

Power Purchase Agreements and their Renegotiation

There are several aspects of the present power purchase agreement (PPA) process that could be easily resolved. The present system of time-consuming, *ad hoc*, post tender negotiation of tariff escalation terms should be dropped, and a single tariff escalation formula should be adopted for all projects (consistent with international best practice for renewable energy projects). The prospective PPA should be provided at the time of tender. All relevant terms and conditions, and particularly the schedules relating to the tariff, should be fixed in advance.

In the short term, the question arises of how to unblock projects stalled for lack of an adequate tariff. Developers argue that the inability to deliver a project on time and to the original tariff estimate has often been the fault of the government, due to inordinate delays in permitting and resolution of land issues. The proposed declassification of geothermal as a mining activity as one of the amendments to the Geothermal Law will be helpful to new projects, but that will not help the currently stalled projects. Therefore renegotiating some PPAs may be unavoidable if some of the currently stalled projects are to move forward. Successful conclusion of the proposed PGE private partnerships will depend on renegotiating prices established in some cases more than 10 years ago at levels that are no longer reasonable in view of the rapid increases in drilling costs over the past 3–5 years.

Notwithstanding that we recognize that PPA renegotiation should be primarily a matter for the contracting parties, i.e., between PLN and the developer, we believe there is benefit to MEMR in issuing a policy statement that sets out the principles that should apply, and the circumstances under which a renegotiation rather than cancellation should be considered—which should be limited to: (i) delays attributable to the fault of government (to be established by an independent third party); (ii) projects where delineation drilling after tender shows the project to be significantly larger, or significantly smaller than estimated at tender, and (iii) projects for which capacity of individual units was stipulated at time of tender, but where the developer subsequently wishes to install larger units (e.g., build 1 x 110 MW rather than 2 x 55 MW as originally stipulated; choice of unit sizes should be left to the developer at final design without penalty). Indeed, we argue that one of the reasons for the new central tender entity is to facilitate any subsequent PPA renegotiation that may be attributable to government delays.

The PPA should also clarify the arrangements for transmission connection. We recommend that, in general, the developer build transmission line to the nearest PLN substation, recovering costs by a non-escalating tariff adder (outside the bid tender price). These costs are a very small percentage of total capital cost, and which are not material to selecting a qualified developer. PLN would take over the line on the date of commercial operation of the generating project, and be responsible for its maintenance.

1 Introduction

1.1 Background

Indonesia has abundant geothermal resources that can help meet the country's rising electricity demand and increase electrification rates. Indonesia's estimated conventional hydrothermal geothermal resource base is generally considered to be among the largest in the world. The Government of Indonesia plans to achieve around 6,000 MW of installed geothermal power capacity by 2020, a more than a fourfold increase of the end-2012 capacity of 1,335 MW. This ambitious plan will require strong government support to materialize. Any shortfall in the expansion of geothermal power generation capacity will most likely be met by additional coal-fired power plants.

Over the past decade, the government has intensified its efforts to scale-up and speed-up geothermal power development.

- In 2003, the Geothermal Law (Law 27/2003) was promulgated, making geothermal the only renewable energy governed by its own law. The law mandated that future geothermal fields must be transparently and competitively tendered for development. It also permitted operators of the fields previously allocated to retain control of their assets. In 2004, the Ministry of Energy and Mineral Resources (MEMR) issued the "Blueprint for Geothermal Development in Indonesia," which was intended as a roadmap to develop 6,000 MW of geothermal power capacity by 2020. In 2005, the Directorate of Geothermal Enterprise Supervision and Groundwater Management were established by MEMR to strengthen sector management and support. This became the Directorate of Geothermal Energy in November 2010. In 2006, MEMR initiated the Master Plan Study for Geothermal Power Development in Indonesia funded by the Japan International Cooperation Agency (JICA), further solidifying knowledge and understanding about developing Indonesia's geothermal resources.
- In 2012, the MEMR issued a feed-in tariff (FIT) policy for geothermal electricity, based on the analytic work supported by the World Bank and/or Global Environment Facility Geothermal Power Generation Development Project.
- In 2012, the Ministry of Finance (MoF) established a geothermal fund with more than $200 million of initial capitalization to mitigate resource risks related to geothermal development. The Asian Development Bank (ADB) provided early technical inputs on the fund's scope and design.[1]

Despite these efforts, progress in the last few years has been slow. The perception that the Indonesian geothermal program has stalled is widespread, and exists among all stakeholders. From 2010–2013, just 135 MW was added, and best estimates suggest that by the end of 2016, no more than an additional 190 MW is likely.[2] No power purchase agreements (PPAs) were signed under the 2012 FIT. A step change in the pace of development for even 4,000 MW to be reached by 2020 is therefore required, achievable only by a focused action program by government to resolve institutional, regulatory, and tariff constraints.

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[1] AECOM, Geothermal Fund Report, Report to ADB, 2011; A. Wahjosoedibjo and M. Hasan. 2012. Geothermal Fund for Hastening the Development of Indonesia's Geothermal Resources. A paper presented to the 37th Workshop on Geothermal Reservoir Engineering. Sanford University, California. January.

[2] In 2014: Patuha, 55 MW. In 2015: Kamojang 5, 30 MW. In 2016: Ulubelu 3, 55 MW; Karaha, 30 MW; and Lahendong 5, 20 MW.

1.2 Objectives

The government has recognized these problems, and has proposed a series of actions to unblock the sector, including:

- amendments of the Geothermal Law (to declassify geothermal as a mining activity);
- a revised tariff issuance; and
- a new regulation on tendering.

To support the development of a new tariff approach, MEMR has requested assistance from the World Bank (IBRD) and ADB. This report describes the findings of the team of technical experts, and presents their recommendations. Our comments on the new June 2014 Geothermal Tariff Regulation are provided in Appendix 7.

1.3 Defining the Geothermal Resource

Estimates of the magnitude of the available Indonesian geothermal resource vary greatly. The 2007 West Japan Engineering Consultants study estimated the exploitable potential across 50 fields at 9,000 MW.[3] In 2011, MEMR revised the country's geothermal potential to 29,215 MW from 27,000 MW a decade earlier[4]—indeed, the 27,000 MW figure is cited in many World Bank reports,[5] and appears to be the basis for claims that Indonesia possesses 40% of the world's geothermal resources.[6]

The basis for these various estimates is unclear, for it is sometimes not fully appreciated that a resource is only that portion of a natural occurrence (whether of energy, petroleum, or minerals) that can feasibly and economically be extracted. Without the basis for such an estimate being made explicit, including assumptions as to the technology pathway and power prices, resource estimates are of very limited value. There is widespread perception that the estimate is too large, but no better estimate has been made, so no one knows by how much.

At the level of an individual geothermal resource, it is important to not only have a good grasp of the size of the resource for planning the development, but equally important to have the reliability of that estimate quantified so that risks can be assessed and financing issues identified.

In 2010, Castlerock Consultants reassessed the more significant geothermal resources in Indonesia on a consistent basis.[7] It is clear from their analysis that some of the resource capacities were not only initially overestimated, but have also had a tendency to be increased over time without new data or justification being available. A more rational, systematic, and transparent methodology is needed.

This issue is, of course, not unique to the geothermal energy sector: a number of estimating and reporting methodologies and codes have been developed in the petroleum and mineral industries, often probabilistically based. Only recently has a similar approach been taken in geothermal practice. Appendix 1 discusses the problem of reporting codes in detail.

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[3] West Japan Engineering Consultants. 2007. *Master Plan Study for Geothermal Development in the Republic of Indonesia*.

[4] The Geological Agency (under MEMR) issues an annual Geothermal Area Distribution Map and the Geothermal Potential in Indonesia.

[5] See, for example, World Bank. 2011. Project Appraisal Report: Geothermal Clean Energy Investment Project. Washington, DC.

[6] J. Wilcox. 2012. Indonesia's Energy Transit: Struggle to Realize Renewable Potential. *Renewable Energy World.com*. 14 September.

[7] Castlerock Consulting. 2010. *Phase 1 Report: Review and Analysis of Prevailing Geothermal Policies, Regulations and Costs*. Jakarta: Ministry of Energy and Mineral Resources.

A complicating factor with geothermal is that the value of the commodity produced—electricity—does not have an agreed international value as is the case for oil or mineral commodities. Therefore, country and even site-specific factors have to be taken into account, including the cost of transmission. Moreover, while petroleum or mineral resource estimates can be made on the basis of simple depletion, geothermal systems may be recharged by heat and fluids during the exploitation of a resource.

1.4 Geothermal Targets

From the standpoint of economic analysis, the optimum quantity of geothermal energy that should be in the energy mix is given by the intersection of the geothermal supply curve, and the avoided social costs of thermal energy. These principles are illustrated in Box 1.

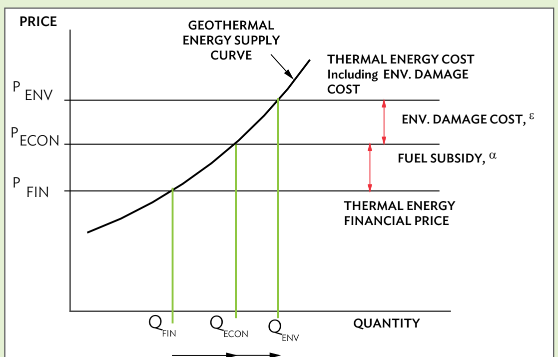
The avoided social cost is defined by *PT Perusahaan Listrik Negara* (State Electricity Company) (PLN) production cost (for which the fuel input, including coal, is now valued at border prices), plus the relevant externality cost, of which the largest component is the avoided cost of the cost of greenhouse gas (GHG) emissions. The local health damage costs associated with local air pollutants such as particulate matter less than 10 microns in diameter, sulphur oxides and nitrogen oxides are also a component of the economic cost of fossil generation, but are quite small compared to GHG emission damages (Section 4.7).[8]

Box 1: Economic Quantity of Renewable Energy

The economic rationale for renewable energy is straightforward: the optimum amount of renewable energy for grid-connected generation—which should be the basis for any target—is given by the intersection of the renewable energy supply curve with the avoided cost of thermal electricity generation. If the price of coal to *PT Perusahaan Listrik Negara* (State Electricity Company) (PLN) is subsidized (as it was in Indonesia until recently), with PLN's avoided cost $\boldsymbol{P_{FIN}}$, then the optimal quantity of geothermal energy is $\boldsymbol{Q_{FIN}}$. If the fuel subsidy α is eliminated, and the true economic cost of coal generation is $\boldsymbol{P_{ECON}}$, then the optimal quantity increases to $\boldsymbol{Q_{ECON}}$.

If one also adds to the cost of coal generation the global environmental damage cost ε, then the true social cost increases further to $\boldsymbol{P_{ENV}}$, and the optimal quantity increases to $\boldsymbol{Q_{ENV}}$. Obviously, the higher the damage cost ε, the higher is the quantity that is justified to avoid these environmental damage costs.

Uncertainty in the costs of geothermal projects results in uncertainty in the supply curve: if costs are higher than expected, the supply curve shifts up, and the optimal quantities decrease. Thus, the Castlerock report shows three supply curves, defined by the variation in cost and resource quality estimates (Figure 1.2).



Q_{FIN} = quantity supplied at PLN's avoided financial cost of thermal energy P_{FIN}, Q_{ECON} = quantity supplied at Indonesia's avoided economic cost of thermal energy P_{ECON}, Q_{ENV} = optimal quantity supplied at Indonesia's economic avoided cost including environmental damage cost P_{ENV}.
Source: Authors' calculations.

[8] The Castlerock report estimated the levelized production cost of coal generation in the Java–Bali grid at 6.3 US¢/kWh; the local damage cost at 0.1 US¢/kWh, and the greenhouse gas (GHG) emission damage cost, based on $20/ton, at 1.4 US¢, i.e., 14 times greater than the local damage cost. Currently, most World Bank project appraisals for geothermal projects use a value of around $30/ton CO_2, at which level the relative importance of local externalities are correspondingly smaller. The $30/ton can be taken to be the World Bank's current estimate of the global social cost of carbon (GSCC) used in economic analysis. This is unrelated to the estimates of market prices (the Clean Development Mechanism [CDU] and the EU emissions trading system [ETS]), which is currently much lower (and which should be used only in financial analysis).

Coal is the least-cost generation option for base-load in Indonesia. That is true even when local environmental externalities are taken into account (i.e., damage costs from local air pollutants). Gas would only be least cost for base load generation at very high valuations of GHG emissions (Section 4.6). Geothermal electricity is by its nature suited to continuous production and therefore would substitute for coal in the large coal-dominated grids of Java–Bali and Sumatra.

The Castlerock Assessment

No such economic analysis was prepared to support the government's geothermal targets. Indeed, one of the first tasks in the Castlerock study was to reassess the field-by-field estimate of probable potential. This analysis takes into account the probabilistic variations in input parameters, and the revised potentials represent the expected value of commercial potential (Table 1.1).

Table 1.1: Castlerock Reassessment of Geothermal Work Area Potentials

		GoI	Castlerock	Change	No Change	Capacity Increase	Capacity Decrease	No Potential
		MWe	MWe	MWe	[ ]	[ ]	[ ]	[ ]
1	Tangkuban Perahu 1, West Java	110	0	**−110**				1
2	Kamojang 5 & 6, West Java	100	60	**−40**			1	
3	Ijen, East Java	110	0	**−110**				1
4	Iyang Argopuro, East Java	55	0	**−55**				1
5	Wilis/Ngebel, East Java	165	39	**−126**			1	
6	Rawa Dano (Kaldera Danau Banten)	110	217	107		1		
7	Cibuni, West Java	10	59	49		1		
8	Cisolok, Cisukarame, West Java	50	30	**−20**			1	
9	Darajat, West Java	110	0	**−110**				1
10	Karaha Bodas, West Java	140	103	−37			1	
11	Patuha, West Java	180	94	**−86**			1	
12	Salak, West Java	40	0	**−40**				1
13	Tampomas, West Java	45	0	**−45**				1
14	Tangkuban Perahu 2, West Java	60	0	**−60**				1
15	Wayang Windu, West Java	240	180	**−60**			1	
16	Baturaden, Central Java	220	0	**−220**				1
17	Dieng, Central Java	115	41	**−74**			1	
18	Guci, Central Java	55	0	**−55**				1
19	Ungaran, Central Java	55	62	7		1		
20	Seulawah Agam, North Sumatra	55	24	−31			1	
21	Jaboi, North Sumatra	7	4	**−3**			1	
22	Sarulla 1 (Namora I Langit), North Sumatra	330	220	**−110**			1	

continued on next page

Table 1.1 *continued*

		GoI	Castlerock	Change	No Change	Capacity Increase	Capacity Decrease	No Potential
		MWe	MWe	MWe	[ ]	[ ]	[ ]	[ ]
23	Sarulla 2 (Silangkitang), North Sumatra	110	128	18		1		
24	Sorik Merapi, North Sumatra	55	53	**–2**			1	
25	Muaralaboh, West Sumatra	220	30	**–190**			1	
26	Lumut Balai, South Sumatra	220	204	**–16**			1	
27	Rantau Dadap, South Sumatra	220	172	**–48**			1	
28	Rajabasa, South Sumatra	220	49	**–171**			1	
29	Ulubelu 3 & 4, Lampung	110	146	36		1		
30	Lahendong 5 & 6, North Sulawesi	40	40	0	1			
31	Bora, Central Sulawesi	5	0	–5				1
32	Merana/Masaingi, Central Sulawesi	20	0	–20				1
33	Hu'u, Sumbawa	20	20	0	1			
34	Atadei, Lembata	5	5	0	1			
35	Sokoria, Flores	5	5	0	1			
36	Jailolo, North Maluku	10	10	0	1			
37	Songa Wayaua, North Maluku	5	5	0	1			
38	Sungai Penuh, Sumatra	110	66	**–44**			1	
39	Hululais, Sumatra	110	137	27		1		
40	Kotamobagu 1 & 2, Sulawesi	40	40	0	1			
41	Kotamobagu 3 & 4, Sulawesi	40	34	**–6**			1	
42	Sembalun, Flores	20	0	**–20**				1
43	Tulehu, Maluku	20	20	0	1			
44	Suoh Sekincau, South Sumatra	230	219	**–11**			1	
45	Sipoholon Ria, North Sumatra	75	0	**–75**				1
46	Bukit Kili, Sumatra	83	23	**–60**			1	
47	Gunung Talang, Sumatra	36	0	**–36**				1
48	Suwawa, Sulawesi	110	14	**–96**			1	
49	Bedugul, Bali	10	208	198		1		
50	Ulumbu, Flores	10	10	0	1			
51	Mataloko, Flores	3	3	0	1			
	Total	4,524	2,774	**–1,750**	10	7	20	14

GoI = Government of Indonesia, MWe = megawatt electric.

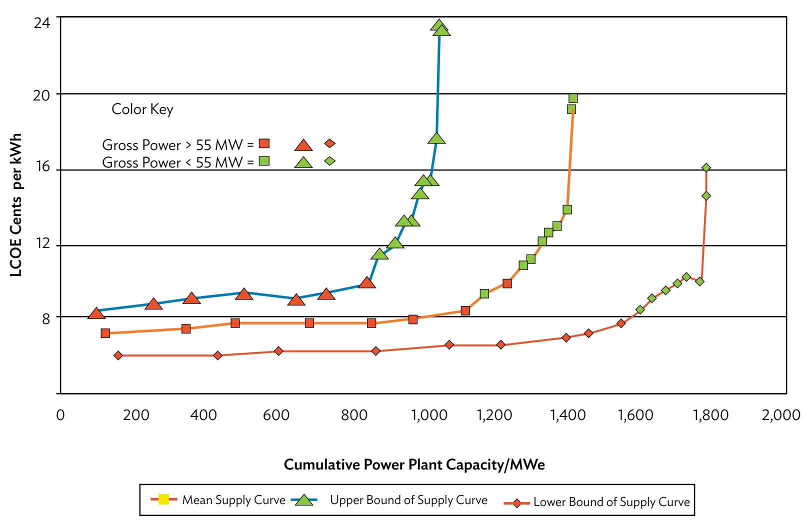
Source: Castlerock Consulting. 2010. *Phase 1 Report: Review and Analysis of Prevailing Geothermal Policies, Regulations and Costs.* Jakarta: Ministry of Energy and Mineral Resources. Exhibit 4.1.

Of 51 *waliyah kerja pertambangan* (WKP) (geothermal work areas) examined, only 10 show no change, and seven show an increase; while 20 WKPs show a decline, and 14 (or 27% of the total number) show zero potential. The total potential of these fields is therefore reduced from 4,554 MW to 2,774 MW. Castlerock's detailed field-by-field assessment estimates suggest cumulative additions of about 2,100 MW by 2020, or a total of 3,435 MW when the existing projects are included.

Castlerock then went on to provide the first rigorous evaluation of the geothermal supply curve for the main geothermal areas: Figure 1.1 shows this for Sumatra. As explained in Box 1, such supply curves are fundamental to the rational formulation of targets. The Castlerock supply curves are grounded in detailed probabilistic modelling of exploration drilling (and its likely probability of success), which permitted calculations of upper and lower bounds.

Where these curves intersect, the cost of coal generation provides the target—so at 6 US¢/kWh, the median supply curve intersects at around 1,000 MW. If the value of avoided GHG emission damage costs were 2 US¢/kWh, the Sumatra target should be set at around 1,300 MW: the lower bound curve (most optimistic) has a value of 8 US¢/kWh at the higher value of around 1,700 MW.

Figure 1.1: Geothermal Supply: Sumatra



kWH = kilowatt-hour, LCOE = levelized cost of energy, MW = megawatt, MWe = megawatt electric.

Note: The (upper) blue line is the upper bound of the cost, but provides, at any given cost, the lowest supply; the (lower) brown line is the lower bound of cost, but provides, for any given price, the lowest level of supply.

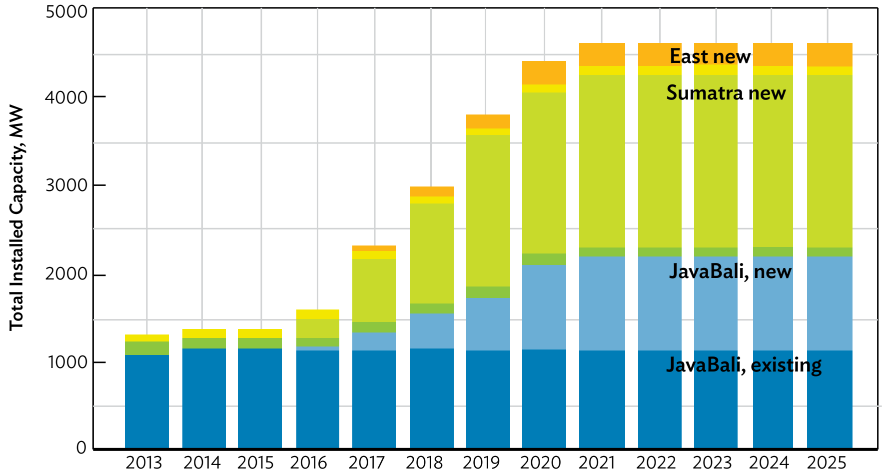
Source: Castlerock Consulting. 2010. *Phase 1 Report: Review and Analysis of Prevailing Geothermal Policies, Regulations and Costs.* Jakarta: Ministry of Energy and Mineral Resources.

2013 World Bank Assessment

In September 2013, the World Bank prepared a revised project status report, provided in Appendix 3. Figure 1.2 shows the resulting distribution of geothermal projects by region.

Note that the bulk of the new capacity that can be expected by 2020 is in Sumatra where 1,820 MW is expected, compared to just 570 MW in Java/Bali, and 240 MW in the eastern islands (where project size is likely to be quite small, constrained by the relatively small loads). The 4,400 MW that can

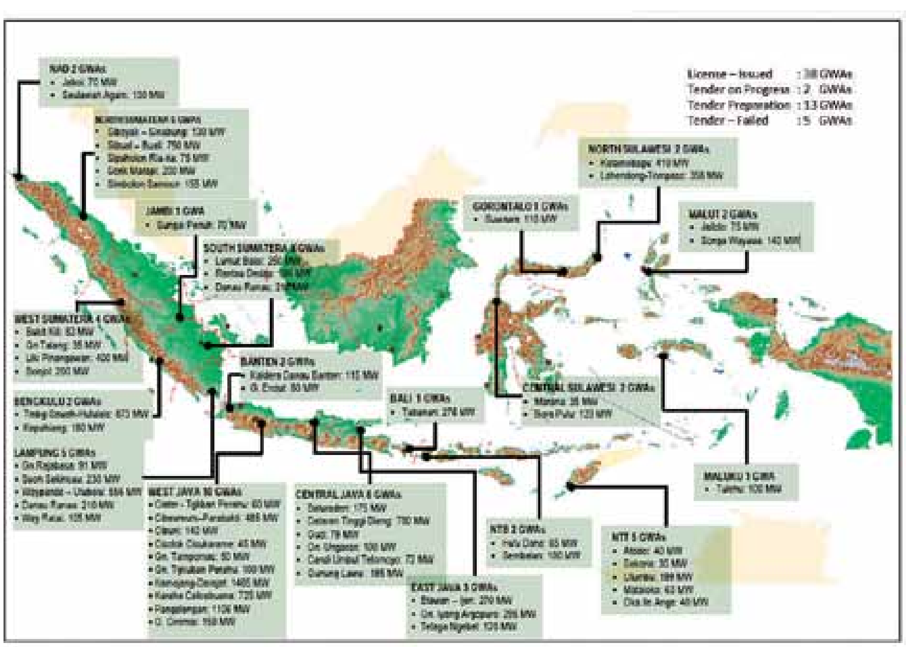
Figure 1.2: Spatial Distribution of Geothermal Projects



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
JavaBali, existing	1,124	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164
JavaBali, new	0	0	0	30	170	400	570	970	1,040	1,040	1,040	1,040	1,040
Sumatra, existing	123	123	123	123	123	123	123	123	123	123	123	123	123
Sumatra, new	0	0	0	190	730	1,115	1,727	1,822	1,942	1,942	1,942	1,942	1,942
East, existing	88	88	88	88	88	88	88	88	88	88	88	88	88
East, new	5	15	18	20	70	110	115	240	273	273	273	273	273
Total	**1,340**	**1,390**	**1,392**	**1,615**	**2,345**	**3,000**	**3,787**	**4,407**	**4,630**	**4,630**	**4,630**	**4,630**	**4,630**

MW = megawatt.
Source: World Bank, 2013.

Figure 1.3: Status of Geothermal Working Areas

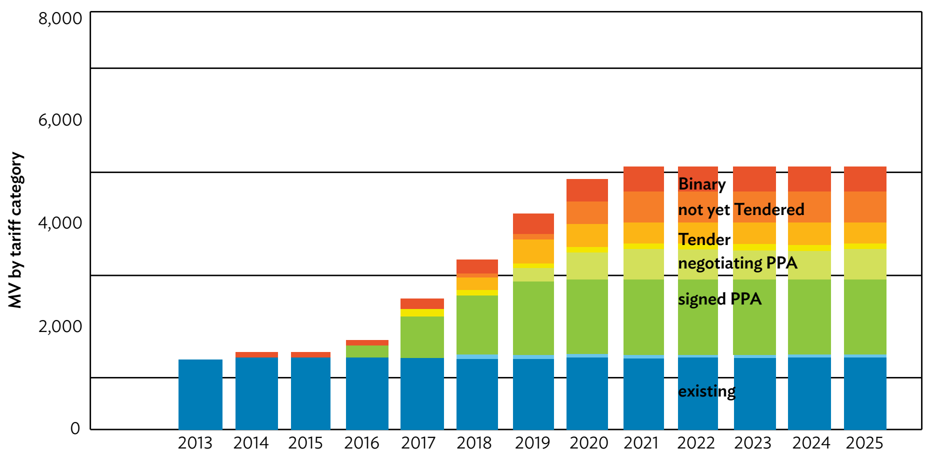


GWA = geothermal working areas, MW = megawatt.
Source: R. Mulyana. 2013. Government's Programs to Accelerate Geothermal Energy. Paper for the Indonesia International Geothermal Convention and Exhibition. Jakarta. June.

reasonably be expected by 2020 is somewhat lower than the total inventory of projects in the more optimistic MEMR forecast (5,816 MW).[9]

Figure 1.4 presents the same data, plus the potential addition of binary bottoming plants (BBPs), but broken down by the status of the tariff. Only 415 MW of new projects expected by 2020 have yet to be tendered (plus an additional 466 MW of potential BBP add-ons). Assuming no renegotiation of existing PPAs, any new tariff issuance would affect only these new projects.

Figure 1.4: Geothermal Projects by Tariff Status



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing	1,335	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375
PLN	5	5	8	10	50	75	75	95	95	95	95	95	95
Signed PPA	0	0	0	190	770	1,165	1,440	1,450	1,450	1,450	1,450	1,450	1,450
Negotiating PPA	0	0	0	0	0	0	227	517	567	567	567	567	567
Reneg PPA	0	5	5	5	115	115	115	115	115	115	115	115	115
Tender	0	0	0	0	0	220	440	440	440	440	440	440	440
Not yet Tendered	0	5	5	35	35	50	115	415	588	588	588	588	588
Binary	0	99	99	116	194	287	395	466	489	489	489	489	489
Total	**1,340**	**1,489**	**1,491**	**1,730**	**2,538**	**3,287**	**4,181**	**4,872**	**5,118**	**5,118**	**5,118**	**5,118**	**5,118**
FracNewTariff	0%	7%	7%	9%	9%	10%	12%	18%	21%	21%	21%	21%	21%
FracNoSigned PPA	0%	7%	7%	9%	14%	20%	31%	40%	43%	43%	43%	43%	43%

PLN PT = *Perusahaan Listrik Negara*, PPA = power purchase agreement.
Source: Authors' calculations.

The view that Indonesia's geothermal targets can be reached at negligible incremental financial cost is a major issue for the sector—a perception encouraged by the relatively high quality of the first few geothermal projects that are now operating (the "low hanging fruit"). The highest cost among the currently operating projects is 9.8 US¢/kWh, while most have costs below 8.5 US¢/kWh. It is also pointed out that whatever may be the difficulties, the 1,335 MW that is in place ranks third in the world, behind only the US and the Philippines.

Nevertheless, by whatever target is used as the yardstick, the impression that the geothermal program has run into serious difficulties is widespread. There is general agreement among all of the stakeholders that reaching 4,000 MW will require major reforms in policy and the institutional framework.

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9 Government of Indonesia, Ministry of Energy and Mineral Resources. 2014. Energy as the Strategic Resources to Fulfil Nation's Growth and Prosperity, and the Role and Prospect of Geothermal. Paper presented at the Indonesia International Geothermal Convention and Exhibition. Jakarta. 4–6 June.

1.5 Scope

Section 2 of this report discusses tariff design, and the advantages and disadvantages of alternative approaches. In particular we discuss the question of whether tariff ceilings should be based on estimates of production costs, or on the basis of estimated benefits.

Implementation and procedure of the proposed methodology is discussed in Section 3. We discuss how tariff ceilings should be applied (for example, if a tender price is offered for a base tariff valid at the commercial operating date (COD) some 6–8 years from tender, one should not calculate a ceiling based on today's conditions), and stress the importance of transparency and stakeholder consultation.

Section 4 presents the calculation of tariff ceilings based on benefits. The main potential pitfall of such calculations is an attempt at great precision: given the uncertainty of all forecasts, such precision would be entirely spurious. For example, in the case of the benefit of the avoided local health damage costs from thermal generation, one should not pretend that these can be estimated exactly, especially where these are based on unreliable extrapolations of health damages estimated in other countries.

Issues surrounding PPAs are discussed in Section 5. Many geothermal projects are currently stalled because of problems with long delays to projects, or resources proving to be much smaller than originally envisaged. Renegotiation of PPAs between PLN and developers should be subject to a formal policy issued by MEMR. The main principles of tariff adjustments are presented here.

Section 6 presents our estimates of the incremental costs of the geothermal targets, and the likely impact on the Ministry of Finance (MoF) subsidy to PLN, followed by a discussion of our recommendations for improvements to the tendering process in Section 7.

A quantitative analysis of the impacts of funding early-stage exploration on the tariff follows in Section 8. While the concept has long been proposed as one of the options for the Geothermal Fund, the calculations presented here further reinforce the previous recommendations of ADB and others for doing so.

Other key constraints to be unlocked are presented in Section 9. This includes the need for a more nuanced presentation of the targets, the potential for PGE commercial partnerships, financing issues (how to mobilize the $10 billion needed to reach the target), geothermal risk mitigation (including the optimal use of the Geothermal Fund), and technology paths to faster development (BBP, larger unit sizes).

The report concludes in Section 10 with a summary of recommendations, as presented to the stakeholder consultation meeting held on 28 January 2014.

The report is interspersed with stakeholder questions or comments posed to us during the consultations leading up to this report, along with our responses to these concerns.

Seven appendixes are provided. Appendix 1 discusses reporting codes. Appendix 2 discusses the connection costs of geothermal projects compared to the costs of connecting large fossil fuel projects. Appendix 3 provides a detailed project status review (as of October 2013). Appendix 4 discusses tariff structure and project finance (and addresses stakeholder consultation meeting concerns about criteria for bankable projects). Appendix 5 presents a detailed technical discussion of technology pathways to faster development (particularly the possibility of retrofitting some existing projects with BBPs where steam conditions are suitable). Appendix 6 presents an estimate of the exploration drilling costs for the next 3,000 MW of geothermal projects. In Appendix 7, we comment on the new geothermal tariff regulation issued by MEMR in June 2014. Finally, in Appendix 8, we comment on the 2014 revision to Geothermal Law No. 27 of 2003.

2 Tariff Design

2.1 General Principles of Tariff Design

The design of renewable energy tariffs should be guided by the following principles:

- A tariff should be rational, and in support of clearly defined objectives. This would ensure that the resources are not developed for their own sake simply because they exist, and because it is generally held to be desirable.
- The tariff methodology should be transparent (and documented as part of a tariff issuance), with clearly stated assumptions.
- A tariff should promote economic efficiency.
- Recovery of any incremental costs should be transparent, credible to lenders, and equitably allocated.
- A tariff should be consistent with legislative requirements (in the case of Indonesia, this means compliant with the 2003 Geothermal Law and its 2014 revision, as well as subsequent regulations).
- A tariff should be adaptable to changing circumstances. This requires the methodology to have a defined basis and provide for review and updating to a clearly stated timetable.
- Stakeholders should be consulted. While consensus is not always achievable, concerns should be addressed.
- The tariff policy environment should be stable. While ceiling prices may require annual updating, the methodology should not be changed at frequent intervals.

The important questions in the detailed design of a tariff for geothermal energy are:

- Whether tariffs should be fixed and available to all (as in so-called "feed-in" tariffs), or whether tariffs should be set competitively.
- If tariffs are fixed, whether they should be based on production costs or on benefits.
- If tariffs are set competitively, whether they should be subject to a ceiling.
- Whether a ceiling should be based on an estimate of production costs, or on benefits.
- How the incremental costs (i.e., the difference between the geothermal tariff and PLN's avoided costs) are recovered.

The distinction between economic and financial analysis is worth noting. Financial analysis deals with the cash flows among the various stakeholders, while economic analysis deals with economic flows from the perspective of the economy as a whole and includes consideration of externalities (such as damage costs from local air emissions and GHG emissions) that are not reflected in financial cash flows. From the economic perspective (i.e., from the perspective of the optimization of resources in an economy), the ideal tariff—whether at the wholesale level (such as PLN's purchases of geothermal power from developers), or at the retail level (PLN's sales to consumers)—should reflect the economic costs of production (and for consumer tariffs, the additional economic costs of transmission and distribution). This ideal tariff should also be determined as a first step, so that the economic costs of other objectives can be quantified (for example, it might be desirable for lifeline consumer tariffs to protect low-income consumers to reflect the equity objective, but the costs of doing so should be made explicit, and ideally be covered not by cross-subsidies from other consumers but by direct government subsidies).

2.2 Fixed Tariffs or Competitively Bid Tariffs

Definitions

Two types of fixed tariff are in general use: FITs and avoided cost tariffs. In international practice, a FIT is generally understood as being based on the production costs of the technology in question, as in the original German model. Malaysia and the Philippines have such FITs (though in neither country is there such a tariff for geothermal). The distinguishing feature of FITs is that they are technology specific, and often differentiated by project size and other technical characteristics (such as additional bonus payable for projects that meet criteria for domestic content or other technical attributes seen as desirable). Fixed FITs have led to overcapacity at high prices, abandonment of programs, and an increasing backlash from consumers and governments (Box 2).

Box 2: Global Experience with FITs

Although fixed feed-in tariffs (FITs) have been very successful in some countries at enabling large installed renewable energy capacity, particularly in Europe, there is increasing concern about the growing impact on consumers and government budgets, leading to some abrupt recent policy reversals (such as in Spain, and in the United Kingdom in the case of solar FITs). In Germany, the consumer surcharge that funds the FIT has now risen to over 5 US¢/kWh, and there are increasing calls for a shift to a more competitive system.[a]

In several developing countries, FITs were unsuccessful at achieving targets, even where tariffs were seemingly quite high: both Brazil and South Africa have replaced FITs by renewable energy auctions, which have proven much more successful at lowering prices and achieving quantity targets. In Brazil, the average price for wind under the original FIT scheme was 10.9 US¢/kWh; in the subsequent auctions, the average price has fallen from 8.5/kWh in 2009 to 6.41/kWh in the 2011 auction.[b]

Sri Lanka had a very successful avoided cost tariff in place from 1996–2009 that successfully enabled a vibrant small hydropower industry (by 2012, 188 MW in 77 projects were in place). Prices were high because the tariff was set on the basis of Sri Lanka's high cost thermal generation, largely based on high speed diesel. But in 2009, with a coal project finally under construction, avoided costs were expected to fall, so developers lobbied successfully for a change to generous technology-specific FITs (for example, offering 19 US¢/kWh for wind). However, there was no sustainable mechanism for funding the incremental costs in place, so after a few memorandums of understanding had been signed (guaranteeing access at the FIT), the program came to a halt, as invoices from the utility (for the incremental cost) remained unpaid. The main lesson from this experience is that generous FITs are not sufficient even to secure physical targets in the absence of agreement on how the incremental costs are to be funded.[c]

[a] In 2012, German residential customers paid $0.25/kWh for electricity, of which the surcharge for the FIT levy accounted for $0.039/kWh, or 13.9% of the average bill. This surcharge rose to $0.0528/kWh in 2013 (excluding VAT)! (Power intensive industrial consumers and the railways benefit from various degrees of exemption). See, for example, K. Neuhoff et al. 2013. Distributional Effects of Energy Transitions: Impacts of Renewable Electricity Support in Germany. *Economics & Environmental Policy*. 2 (1). pp. 41–45.

[b] See World Bank. 2014. *Renewable Energy Support Mechanisms: An Economic Analysis of the Design and Incentives and their Sustainability*. Washington, DC. However, it remains to be seen whether some of the low prices bid in the Brazilian (and other Latin American) auctions will actually be achieved.

[c] Ibid. Chapter 5.

An avoided cost tariff is one based on the benefits of renewable energy, which can be defined as the avoided costs of the buyer. In the case of geothermal, the benefits are represented by PLN's (avoided) cost of the thermal generation technology that geothermal replaces. In most cases this is coal, although on some small eastern islands it may be oil. Geothermal also avoids the environmental damage associated with fossil generation, and the costs of the volatility of fossil fuel prices.

By definition, avoided cost tariffs are not specific to the renewable energy technology in question—they should apply to all renewable energy technologies.[10] This is based on the proposition that from the perspective of avoiding the environmental impacts of thermal generation, it does not matter whether emission reductions are achieved by any specific technology—and that it is better for the marketplace to decide which technologies are most cost-effective than for government to decide what technology mix is appropriate. Viet Nam and Sri Lanka had such avoided cost tariffs for qualified renewable energy generators from 1996 to 2009.

The distinguishing feature of fixed tariffs, whether based on estimated production costs or on avoided costs, is that they are potentially available to all (who can meet the technical requirements of the grid code and who are judged financially capable of completing the project in a timely fashion).

Although the 2012 Indonesia geothermal tariff was announced by MEMR as a FIT (Table 2.1), in fact it was based on estimates of the avoided costs in the Castlerock report.[11]

Table 2.1: The 2012 Geothermal FIT

No.	Region	**Tariff** (US¢/kWh)	
		High Voltage	**Medium Voltage**
1	Sumatra	10	11.5
2	Java, Madura, and Bali	11	12.5
3	South Sulawesi	12	13.5
4	North Sulawesi	13	14.5
5	NTB, NTT, Maluku, and Papua	15	16.5
6	Maluku and Papua	17	18.5

NTB = Nusa Tenggara Barat (West Nusa Tenggara), NTT = Nusa Tenggara Timur (East Nusa Tenggara), US¢/kWh = cents per kilowatt-hour.
Source: Government of Indonesia, Ministry of Energy and Mineral Resources. Ministerial Regulation No. 22/2012.

Economic Efficiency

Competitively determined tariffs are the best guarantee of economic efficiency. Fixed FITs, set by the government on the basis of estimated production costs, are suitable only where the sole rationale for additional renewable energy is the achievement of physical targets.

If the government of a developing country desires, as a good global citizen, to place a value on environmental goals (and be prepared to cover the incremental costs), it becomes even more important that only the most cost-effective projects are implemented. That is best achieved by competitive tender.

In Indonesia, the implication of a fixed FIT available to all (as in the 2012 MEMR tariff issuance) is that tender awards would be made without consideration of price (in so-called "beauty contests"). Good

[10] However, in practice, governments generally stipulate some maximum size—for example, in Viet Nam, the avoided cost tariff is available only for renewable energy projects no greater than 30 MW. Thus, while small hydropower projects no greater than 30 MW automatically benefit from the avoided cost tariff, larger hydro projects are subject to project specific negotiated tariffs.

[11] Castlerock Consulting. 2010. *Phase 1 Report*.

developers (and especially international ones) are discouraged by such a procedure because they see it as subjective and unreliable.

It is worth noting that none of the world's leading geothermal countries (the United States, the Philippines, Mexico, Italy, New Zealand, and Iceland) have FITs for geothermal (Table 2.2).[12] Countries that do have fixed FITs tend to set them at very high levels because their resources are very small or low-grade (e.g., Germany at €0.25/kWh, 33.7 US¢/kWh)[13] or because of special circumstances, such as Japan (27–41 US¢/kWh) where the motivation is the acute energy crisis in the aftermath of the shutdown of its nuclear plants following the accident at the Fukushima nuclear power plant.

Table 2.2: FITs for Geothermal Energy

	Size	Currency/kWh	US¢/kWh
Germany[a]		0.25 €	33.7
Japan[b]	<15 MW	27.3 Y	26.6
	>15 MW	42.0 Y	40.9
Italy[a]	<1 MW	0.20 €	27.0
Taipei,China[a]		4.80 NT$	17.0

kWh = kilowatt-hour, MW = megawatt, NT$ = NT dollar.

Sources:

[a] E. Büscher. 2012. Feed-in Tariffs Blessing or Curse for Geothermal Energy? Worldwide Background and Overview. *Geothermal Resource Council Transactions*. Vol 36.

[b] Government of Japan, Ministry of Economy, Trade and Industry. http://www.meti.go.jp/english/policy/energy_environment/renewable

Setting fixed FITs on the basis of production costs is also subject to the same problems as setting tariff ceilings on the basis of production costs.

2.3 Ceilings

Indonesia introduced the concept of a ceiling price (9.7 US¢/kWh) in 2009,[14] below which the winning tender bid would automatically be accepted, but above which the bid was subject to negotiation with PLN. It is unclear what are the principles that govern such ad hoc negotiations (other than PLN's desire to minimize the cost). It appears that no PPAs above 9.7 US¢/kWh were negotiated with PLN under this provision.

There are two reasons why competitive tenders should be subject to ceiling prices:

- to ensure that the bid price is reasonable (which it might not be if there are defects in the tender process due to insufficient competition, collusion among bidders, or unrealistic bids offered by inexperienced bidders); and
- to ensure that the bid price does not exceed the benefits of the project.

Ceilings on competitively bid prices for renewable energy are widely used in international practice (Brazil, Peru, South Africa), and are also appropriate for Indonesia. Ceiling prices are also used in India for solar.

It may be supposed that in a tender subject to a ceiling price, winning bids will be very close to that ceiling price. The international experience is unclear. For example, in the renewable energy auctions in Peru, winning bids have been from 53% to 82% of the ceiling price (Table 2.3).

[12] Italy does have a FIT for geothermal, but only for projects smaller than 1 MW.

[13] The system is complex, with several bonuses above the basic rate and several size categories: the figure cited here is for a typical project.

[14] Indonesia. Ministerial Regulation (MEMR) 32/2009.

Table 2.3: Bid Prices and Ceilings in Peru Renewable Energy Auctions

		Winning bid	Ceiling	Winning bid as % of ceiling
		$/MWh	$/MWh	%
Small hydro	2009	60.2	74	81%
Solar	2010	221.0	269	82%
Wind	2010	80.4	110	73%
Biomass	2010	63.5	120	53%

$/MWh = dollar per megawatt-hour, hydro = hydropower.

Sources: Osinergmin. http://www2.osinerg.gob.pe/EnergiasRenovables/contenido/Resultado1raSubasta.html; International Renewable Energy Agency. 2013. *Renewable Energy Auctions in Developing Countries.* IRENA.

On the other hand, the experience in South Africa suggests there may be a benefit to an undisclosed ceiling price. In the first auction round (for wind, solar photovoltaic, and concentrated solar power, 2011) the average contract prices were from 98% to 114% of the disclosed ceilings. In a second 2012 round, the ceilings were undisclosed, and average prices were much lower (11.2 US¢/kWh for wind, as opposed to 14 US¢/kWh in the first round). But this may be as much a reflection of how the ceilings were set, i.e., on the basis of estimated production costs, as of the disclosure of the ceiling price.

Most international auction experience has been with small hydro and wind, where auctions were for a large number of sites that bid for the right to a long-term PPA at the bid price. For both these technologies, establishing the size of the resource is easy compared to that required for geothermal energy. The ceilings in most cases are based on estimates of production costs, which for small hydro, wind, and solar power projects are straightforward. Tenders for Indonesian geothermal projects are of an altogether different type, where one has (ideally) many bidders for a single site about which there is much resource uncertainty.

One may note that from the point of economic efficiency, it would not matter if bid prices were close to the ceiling, because it is only important that the cost does not exceed the benefit. However, the question would then be whether the corresponding producer surplus, which derives from the economic rents associated with sites that can be developed at lower cost, should indeed accrue to producers, or to government (electricity consumers). If the principal objective is to develop the huge geothermal potential, that can only be achieved by building up a healthy private sector geothermal industry, and nothing would give a better incentive than making geothermal development profitable (i.e., letting producers capture the surplus at lower-cost sites). In time, if the tender process is efficient, these profits will be competed away.

Ceiling prices are not meaningful if they are negotiable on an individual basis after tender. However, whatever the rationale, ceiling prices should be reassessed from time to time. A ceiling established several years ago may no longer be reasonable, or reflect benefits, today. For example, production costs may change because of inflation, or benefits may change because international fossil fuel prices rise.

The Indonesian 9.7 US¢/kWh threshold established in 2009 would clearly no longer be appropriate for new projects today, because costs have risen considerably since then as a result of general inflation. Drilling costs in particular have increased faster than inflation. For this reason, international best practice is for renewable energy tariffs and ceiling prices to be reviewed on an annual basis by the relevant body, which are usually regulators or ministries of energy.

2.4 Production Costs or Benefits as a Basis for Ceiling Prices?

If the reason for a ceiling is that projects should be economically efficient, namely that costs, even if competitively determined, should be less than benefits, then the ceilings should be determined by the government's valuation of the benefits of geothermal energy.

But even if the main rationale of a ceiling is to ensure that bid prices are technically reasonable, attempts to calculate plausible ceilings on the basis of production costs have significant problems:

- Even bid prices with technically reasonable costs, and by technically and financially capable bidders, may exceed the benefits, so economic efficiency is not assured. Since the incremental costs of geothermal energy to PLN are paid for by government through the MoF's Public Service Obligation (PSO), the requirement for economic efficiency is paramount.
- Government can never have as much reliable information about costs of projects as developers. However, PLN's costs are well known and can be estimated without great controversy about their validity. PLN and MEMR have close relationships at the technical level, and few of the data required are confidential.
- Production costs depend on a range of financial variables such as the developer's return on equity, which are difficult for governments to determine objectively (what is a "fair" rate of return for a project with high risk: 12%? 16%? 20%?).
- MEMR can estimate the production costs for a particular project size and probable resource characteristics based on engineers' best estimates of most likely, or average values. But given the wide range of uncertainty for geothermal projects, using average values as a ceiling excludes (by definition) 50% of projects in that category. There is no objective answer as to whether the ceiling should be 10% or 20% or 50% above the average.

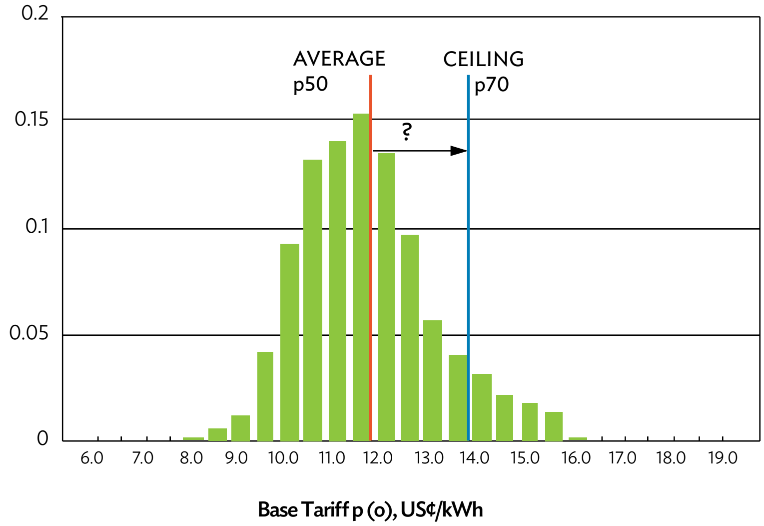
This last problem is illustrated in Figure 2.1. In project economic analysis, one deals with uncertainty in project assumptions with a formal risk analysis, using a technique called a Monte Carlo simulation. The financial internal rate of return (FIRR) given the tariff, or the required tariff to achieve a given equity FIRR, is calculated 1,000–10,000 times, at each iteration using a different set of values for each input assumption (sampled from their probability distributions). The result is a probability distribution of the FIRR (or tariff), as shown in Figure 2.1.

In this illustrative example, the average required tariff is 11.5 US¢/kWh, which corresponds to the most likely set of assumptions. But is this a reasonable value for the ceiling, because that would exclude 50% of the cases (p50)? Even the values above the average are still technically reasonable under circumstances less favourable than the average (e.g., more than expected number of wells for delineation drilling—a circumstance even the best planned drilling program cannot avoid). p70, which excludes 30% of cases, is 13.5 US¢/kWh. p100, which includes all cases, is 16 US¢/kWh. But how does one decide where to draw the boundary? There is no rational basis to decide how much to the right of the average the ceiling should lie.

There is a perverse incentive in the definition of a production cost-based ceiling tariff, as earlier proposed by MEMR (Table 2.4) which is classified according to size categories, and calculated using the MEMR production cost model.

Clearly, with specification as a step function, no projects will be proposed between 56 MW and around 65 MW (at which the tariff is 10.5 US¢/kWh), when a 55 MW sized project obtains a tariff of 12.5 US¢/kWh. In any event, there are substantial scale economies beyond 55 MW, so the size classification should be extended to at least 220 MW. Moreover, instead of a step function, the ceiling would better be

Figure 2.1: Production Cost Estimates



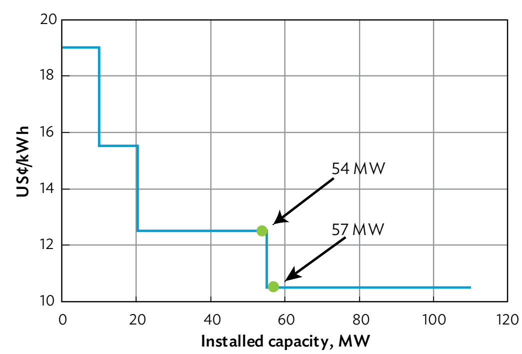
US¢/kWh = cents per kilowatt-hour, p50 = 50% probable value, p70 = 70% probable value.
Source: Authors' calculations.

Table 2.4: Size Classifications

	US¢/kWh
>55 MW	10.5
20<MW<55	12.5
10<MW<20	15.5
<10	19.0

MW = megawatt, US¢/kWh = cents per kilowatt-hour.
Source: Government of Indonesia, Ministry of Energy and Mineral Resources. 2014. Geothermal Production Cost Model. January.

Figure 2.2: Production Cost Based Tariff, Size Classifications



MW = megawatt, US¢/kWh = cents per kilowatt-hour.
Source: Authors' calculations.

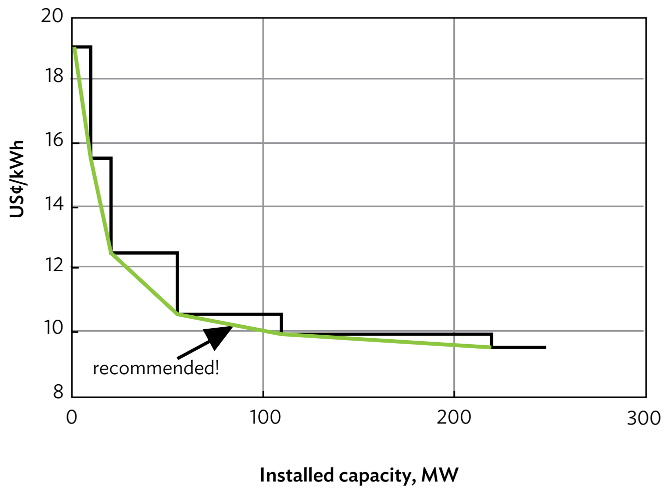
stated with linear interpolation between the calculated points, as illustrated in Figure 2.3.

In short, there are no credible mechanisms for setting tariff ceilings on the basis of production costs. However, the production cost function, as for example calculated with the MEMR production cost model, does have several other useful and important applications; for example, we propose use of such a model for PPA renegotiations.[15]

There are, of course, some issues in the calculation of the benefits of geothermal energy (Section 4). Some benefits are very hard to value, and future fossil fuel prices are difficult to forecast. However, many such assumptions can be drawn from credible international sources, such as the oil and coal

[15] See Section 5.

Figure 2.3: Recommended Form of the Production Cost Function



MW = megawatt, US¢/kWh = cent per kilowatt-hour.
Source: Authors' calculations.

price forecasts published annually by the International Energy Agency (IEA), and assessments of the benefits of GHG emissions from the Intergovernmental Panel on Climate Change (IPCC).

Concerns expressed by stakeholders about the current tender process are legitimate. However, these should be tackled directly by improving the technical capacity of tender committees, and using the Geothermal Fund for up-front exploration to improve the quality and value of the data available to bidders, rather than setting ceiling prices based on arbitrary definitions of "reasonable" production costs. Table 2.5 summarises the comparison of the two approaches.

Table 2.5: Comparison of Approaches

Criterion	Production costs	Benefits (avoided costs)
Transparency	Good, provided assumptions are clearly stated, and the methodology published.	
Economic efficiency	Not assured, since production costs say nothing about benefits.	Assured, since projects whose costs>benefits will not be built.
Data problems	Government can never know as much about projects as developers.	PLN's costs are easily established.
Project variability	High variability of project conditions. Actual capital costs may vary greatly according to manufacture order books, interest rate variability, etc.	Project cost variation irrelevant: for a ceiling price, it is only important that benefits>costs as estimated in competitive tender.

PLN = *PT Perusahaan Listrik Negara.*
Source: Authors' calculations.

One of the arguments against the avoided cost approach is that there is a higher risk of project not going ahead if there are increases in project costs. While that may well be true, if the avoided cost tariff is based on a sound economic rationale, then if a project does not materialize because its costs increase to the point that the published avoided cost tariff no longer provides the necessary revenue, then that is a good outcome: projects with costs higher than the economic avoided cost should indeed not proceed.

3 Implementation Issues and Procedures

3.1 Tariff Ceilings and Escalation

It is sometimes assumed that tariff ceilings should be based on today's costs (if based on production costs), or today's benefits (if based on PLN's avoided costs). But that is not reasonable if the intent is to apply the ceilings to a tender for a project that will deliver benefits only 6–8 years from the tender date.

At the time of tender, developers estimate a base price that applies to the COD. That date may be some 6–8 years in the future. A project tendered today may only start operation in 2020–2022. The developer's cost estimates for power plant construction, for example, would be based on the expectation of construction costs several years in the future, when costs may have changed significantly—whether as a matter of changes in market conditions for imported equipment or inflation.

This is true regardless of whether the ceiling is set on the basis of production costs, or on the basis of avoided costs (benefits). The estimates of production cost proposed by MEMR (Section 2, Table 2.4) are today's estimates of reasonable costs, but it is obvious that these would not be reasonable as ceilings for a tender bid price that only comes into effect 6–8 years in the future.

In the case of benefits-based ceiling prices, MEMR must make a forecast of what are the likely benefits at the COD. This, of course, requires a methodology for making such forecasts—the benefits in 2020 will depend on a range of assumptions about future coal prices, future coal project construction costs, and the future value of GHG emissions—just as the developer's estimate of the base tariff depends on his forecasts of the variables that affect investment and operation and maintenance (O&M) costs some years in the future.

One might object that such forecasting is a technically complex analytical task requiring many judgements that may be beyond the experience of MEMR. However, many of the necessary judgements are routinely made by entities that specialize in such forecasts, which are not only published on the web but which have widespread credibility and international acceptance. To forecast future oil and coal prices, one can reasonably rely on the World Energy Outlook reports published annually by the IEA; and for escalation of manufactured goods (say for power plant construction) one may use forecasts of the manufactured unit value (MUV) index published quarterly by the World Bank.

3.2 Transparency

International practice provides many lessons about the importance of transparency and accountability. In 1996, Sri Lanka introduced Asia's first avoided cost tariff for renewable energy, based on the avoided costs of thermal electricity. At the time, Sri Lanka lacked an independent regulator or government renewable energy agency, so responsibility for the annual calculation of avoided cost was given to the

Ceylon Electricity Board, which was also the buyer of electricity. Lack of clarity and transparency in these calculations led to court action against the Ceylon Electricity Board by some developers.

The lessons were heeded: after the responsibility for tariff-setting was put in the hands of the newly created Sri Lanka Public Utilities Commission (SLPUC), it made available the calculation spreadsheet for the new FITs—which now sets the standard for tariff transparency (Box 3).

3.3 Recovery of Incremental Cost

International experience shows that credible recovery of the incremental costs of renewable energy is the single most important requirement for the success of a renewable energy tariff.

Malaysia's newly introduced renewable energy FIT sets the standard for the Association of Southeast Asian Nations (ASEAN) for transparent recovery of the incremental costs of renewable energy. To finance the initial FIT payments, the government advanced $60.4 million to the renewable energy fund. The amount is to be paid back. Subsequently, the fund will rely on income from the additional 1% tariff on monthly electricity rates (only applicable to consumers of 300 kWh and above). In Thailand, the funds to pay the renewable energy adders are derived from the Energy Conservation Fund, whose source of revenue is a tax on petroleum products.[16]

Unfortunately, in Sri Lanka, although the tariff itself is transparent, the arrangements for recovery of incremental costs were not assured. The utility pays only its avoided financial cost, which is substantially below the cost of new projects, especially for wind. Invoices presented by the Ceylon Electricity Board to the Renewable Energy Fund remained unpaid, with the result that very few memorandums of understanding that guarantee access to the generous FIT were signed—without which projects are unbankable.

In Indonesia, the present mechanism to assure PLN's financial credibility is well understood (given a low consumer price, PLN's revenue requirements are made up by subsidy from MoF), though the history of defaults has not been forgotten by developers. The introduction of performance-based regulation should further enhance PLN's ability to raise sufficient funds to meet its investment requirements.[17] The substantial geothermal capacity under Fast Track Program 2 (FTP2) qualifies for sovereign guarantees, and other foreign investment and purchase power parity projects could also be protected by partial risk guarantees from the Multilateral Investment Guarantee Agency (MIGA) and the *PT Penjaminan Infrastruktur Indonesia, Persero* (Indonesia Infrastructure Guarantee Fund).

However, in view of the current arrangements, and the desire of MoF to reduce the level of subsidy to PLN, it is important to demonstrate that geothermal projects that potentially increase the subsidy requirement are justified by the economic benefits to Indonesia. Fixed FITs or ceilings based on production costs do not assure such economic efficiency.

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16 Renewable energy producers in Thailand get the market price for electricity, plus a fixed payment (the "adder") dependent on the renewable energy technology in question.

17 Performance-based regulation is an approach to rate-making that provides better incentives to operate more efficiently than the traditional approach of setting tariffs based on costs plus a predetermined rate of return.

Box 3: Examples of Renewable Energy Tariff Transparency

In Sri Lanka, the regulator published this spreadsheet as a basis for public hearings on proposed revisions to the tariff. All figures here relate to tariffs for wind-based electricity.

Tariff Calculation for Wind-Based Electricity

Capital Cost (SLRs million/MW)	212					
Construction Time (Years)	2					
Construction Year	1	2				
Equity (SLRs million)	40%	0%				
Debt (SLRs million)	10%	50%				
IDC (SLRs million)	2.76	16.54				
Capitalized Total (SLRs million)	231.29					
Loan repayment Period	6					
Yearly Maintenance Cost (% of Capital Cost)	4.00%					
Plant Factor (%)	32.00%					
Capacity (MW)	1					
Year	1	2	3	4	5	6
ROE	20.35	20.35	20.35	20.35	20.35	20.35
Principle payment	23.13	23.13	23.13	23.13	23.13	23.13
Cumilative principle paid at start	0	23.13	46.26	69.39	92.52	115.65
Interest payment	18.04	15.03	12.03	9.02	6.01	3.01
O&M	8.48	8.48	8.48	8.48	8.48	8.48
Total Cost	70.00	67.00	63.99	60.98	57.98	54.97
Production	2.80	2.80	2.80	2.80	2.80	2.80
Escallable O&M included (SLRs/kWh)	3.03 @		7.64%			
Years	Yr 1-8	Yr 9-15	Yr 16-20			
Tariff (SLRs/kWh)	20.80	10.29				
Escallable Incentive (SLRs/kWh)	0.00	0.00	1.68 with		5.09%	Escallation a
Escallable O&M included (SLRs/kWh)	3.03	3.03	3.03 @		7.64%	
Year	1	2	3	4	5	6
Tariff Under 3 Tier Scheme	20.80	21.04	21.28	21.55	21.84	22.15
Year	-1	0	1	2	3	4
Net Cashflow	87.56	4.96				
O&M	8.48	9.1275148	9.8244725	10.574648	11.382106	12.25122
Levelized Tariff (SLRs/kWh)	19.43					

kWh = kilowatt-hour, MW = megawatt, O&M = operation and maintenance, ROE = return on equity, SLRs = Sri Lanka rupees, SLRs million = million Sri Lanka rupees.

Source: Sri Lanka Public Utilities Commission, 2008.

In the Philippines, the National Renewable Energy Board (NREB) issues feed-in tariffs (FITs) based on representations from developers and the Department of Energy. Assumptions and NREB determinations are published (all figures below relate to tariffs for wind-based electricity).

Technology	Propesed by Developers	Estimates by DOE	Latest Estimates by NREB
Representative size (MW)	30.0	30.0	30.0
Project Cost ($ per kW)	2,758	2,255	2,758
EPC Cost	1,983	1,586	1,983
Net Capacity Factor (%)	25.0	25.0	25.0
O&M Cost ($ thousand/unit/year)	134	100	100
Equity IRR (%)	20.1	16.5	16.0
After-Tax WACC (%)	11.2	12.0	10.0
FIT (Php per kWh)	11.29	9.27	10.05

EPC = engineering, procurement and construction, IRR = internal rate of return, MW = megawatt, O&M = operation and maintenance, PHP = Philippine Peso, WACC = weighted average cost of capital.

Source: Government of the Philippines, National Renewable Energy Board.

In Viet Nam, the regulator (Electricity Regulatory Agency of Viet Nam) published the avoided cost tariff methodology report on the web, following a series of stakeholder consultation meetings. The calculations for the annual update are prepared by the National Load Dispatch Centre.

3.4 Tariff Setting as a Process

Tariff setting is not a one-time exercise that can be set aside for a few years once the regulation is published, and revisited if and when some problem arises. Rather, tariff-setting should be seen as an ongoing process, with a dedicated team in MEMR's geothermal directorate assigned to maintain a database, monitor the external conditions, update and maintain the MEMR production cost model,[18] and be responsible for the necessary annual update, including stakeholder consultations.

Such units are widespread in international practice. Countries with an independent electricity regulator or Public Utility Commission (e.g., Sri Lanka), or a special board charged with setting tariffs (e.g., New and Renewable Energy Board, Philippines) have such a technical unit as a matter of course. There are also precedents in other countries where the regulatory body is housed within an appropriate ministry or other entity (for example, in Viet Nam the Electricity Regulatory Authority of Viet Nam, which is an entity of the Ministry of Industry and Trade, has a tariff unit with these functions).

3.5 Conclusions on Implementation Procedure

Annual Issuance

Tariff ceilings should be issued by MEMR on an annual basis, no later than 15 December of each year, with values which would apply to tenders conducted in the following calendar year.

MEMR should issue a draft ceiling no later than 15 October of each year, followed by a stakeholder consultation meeting no later than 15 November of each year, said date being the deadline for submission of any written comments for consideration by MEMR.

Non-Negotiable Ceilings

Tariff ceilings should be non-negotiable. If the best price offer at tender exceeds the ceiling, then the tender shall be deemed to have failed on grounds that no economically efficient project has been offered (though from the economic perspective, this is a good outcome insofar as an uneconomic project should indeed not proceed). Indeed, a project area can always be re-tendered if increases in future benefits permit.

Transparency

The methodology of the tariff ceiling calculation should be published by MEMR.

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[18] Although this model is not recommended for calculation of tariff ceilings, we believe it can play an important role in PPA renegotiations (see Section 5).

4 Tariff Ceilings Based on Benefits

The purpose of a tariff ceiling is to ensure that the only projects that are built are those in which costs do not exceed the ceiling. As noted, the benefits of geothermal projects can be defined as the avoided economic costs of thermal generation. Therefore the first step in defining such ceilings is to examine what thermal generation option would in fact be displaced—which will not be the same in all parts of Indonesia.

4.1 Alternatives to Geothermal

Geothermal projects have high annual capacity factors, and therefore can provide base load. Three types of thermal alternatives are relevant:

- In the large interconnected grids of Sumatra and Java–Bali, the alternative is large, modern coal projects, operating at high efficiency (supercritical, and in Java, ultra-supercritical) and fitted with state-of-the-art environmental controls for the mitigation of local air pollutants (particulates, nitrogen oxides, and sulphur oxides).
- In the smaller grids of the other islands, there are small coal projects (less than 50 MW), of much lower efficiency and higher unit costs, with less effective emission controls for local air pollutants. PLN has some doubts about the practicality of this alternative, given its limited experience with such small coal projects to date.[19]
- On islands for which small coal projects are not technically feasible or environmentally acceptable, the only practical alternative for electrification is diesel.

This means that the benefits of geothermal generation are likely to be quite different across Indonesia, and three sets of tariff ceiling are therefore required.

One might argue for a finer geographical differentiation—for example, one might differentiate between ultra supercritical coal projects in Java–Bali, and smaller subcritical coal and mine-mouth projects in Sumatra. However, mindful that the tariff ceilings as applied to tender bid prices are forecasted 6–8 years into the future, the differences that may apply to these various project types are much smaller than the uncertainty that applies to forecasting. Great precision in project differentiation would be spurious.

[19] PLN's most recent RUPTL includes plans for some 70 small-scale coal systems ranging in size from 3 MW–25 MW.

Stakeholder Comment 1: Why Is Geothermal Energy Not Also Benchmarked Against Gas Rather Than Only Coal?

Comment:

Since gas is being used on Java for base load, the avoided cost calculation should be based on the mix of coal and gas actually used, rather than 100% coal as proposed. Geothermal should be considered as a substitute for liquefied natural gas (LNG) on Java and Sumatra in view of the huge investments in LNG.

Reply:

Use of gas would increase the avoided cost component of the benefit calculation.

It is true that in West Java, a significant amount of gas is currently being used for base-load generation. However, this is an artifact of the take–or–pay provisions of the current gas supply contracts, which are short-term contracts not expected to persist over the long term. Moreover, because of the delays in the large Fast Track Program 1 coal projects, gas is being used to make up the base-load shortfall. These conditions are also not expected to persist in the long term. PLN's *Rencana Usaha Penyediaan Tenaga Listrik* (RUPTL) (Electricity Power Supply Business Plan) makes it clear that in the future, gas will be used primarily for intermediate and peak loads.

More importantly, the carbon dioxide emissions per kilowatt-hour (kWh) generated in a gas combined cycle gas turbine plant are 38%–40% of the corresponding emissions from a modern coal project.[a] Consequently, while the avoided cost of gas generation will be higher, the avoided externality cost will be significantly smaller. Also, though not monetized here, gas projects have no emissions of sulphur oxide and particular matter less than 10 microns in diameter.

Since the principal rationale for geothermal, and the need for additional subsidy to cover its incremental cost, is to offset the environmental impact (and especially the emissions) of coal, it would be unwise to dilute this rationale, simply to increase the ceiling price. Indeed, geothermal and natural gas (whether pipeline or LNG) are both clean fuels, and are therefore complements, not substitutes.

		Large coal, subcritical	Large coal USC	Small coal	CCGT gas
Size class		200	1000	50	
IPCC default	Kg/GJ	96.1	96.1	96.1	56.1
Efficiency	From PLN RUPTL	0.34	0.40	0.26	0.56
Heat rate	kJ/kWh	10,588	9,000	14,063	6,429
GHG emissions	Kg/kWh	1.018	0.865	1.351	0.361
Ratio gas:coal	[ ]	0.35	0.42	0.27	

CCGT = combined cycle gas turbine, GHG = greenhouse gas, GJ = gigajoule, IPCC = Intergovernmental Panel on Climate Change, Kg = kilogram, kJ = kilojoule, kWh = kilowatt-hour, PLN = *PT Perusahaan Listrik Negara* (State Electricity Company), RUPTL = *Rencana Usaha Penyediaan Tenaga Listrik* (Electricity Power Supply Business Plan), USC = ultra-supercritical.

Source: Authors' calculations, based on data from IPCC and PLN.

[a] From the table above, we see that GHG emissions per net kWh from gas combined cycle gas turbine are between 27% and 42% of the emissions from a coal project.

Sources: Written comments of Indonesia Geothermal Association (INAGA), March 2014; Representation of Chevron at the stakeholder meeting at MEMR on 12 March 2014; Comments provided by Chevron, 11 March 2014.

4.2 The Components of Avoided Costs

The total economic benefit of geothermal energy consists of seven potential components:

(i) the avoided variable cost of thermal generation;

(ii) the avoided fixed cost of thermal generation (capital recovery and fixed O&M);

(iii) the avoided global externality cost of thermal generation;

(iv) the avoided local externality cost of thermal generation;

(v) the avoided costs to MoF of fossil fuel price volatility;

(vi) the avoided costs of transmission interconnection of thermal projects; and

(vii) the incremental local regional economic benefits of geothermal.

4.3 Macroeconomic and Global Energy Price Forecasts

Many of the variables used in the calculation depend on macroeconomic forecasts, and forecasts of the future price of fuels. In the illustrative calculations presented here, dollar inflation is taken at 2.5%, and Indonesian inflation at 4.5% (and with the base year exchange rate adjusted accordingly).

A range of coal and oil price forecasts is available from the most recent 2013 World Energy Outlook published by the IEA.[20] Fuel price forecasts provided by the 2013 World Energy Outlook for crude oil and coal are presented in Table 4.1. Prices of fossil fuels are seen to rise (in real terms) under current policies, but over the long run are expected to rise much less under the assumption of effective world-wide policies to reduce GHG emissions ("new policies"), and even fall in the "450 Scenario" in which the Intergovernmental Panel on Climate Change (IPCC) goals to limit atmospheric CO_2 to 450 parts per million are assumed to succeed. In the absence of much evidence that global agreement on GHG emission reductions are imminent, we propose the World Energy Outlook "current policy" scenarios as the basis for fuel price forecasts for renewable energy tariff-setting in Indonesia.

Table 4.1: World Energy Outlook 2013, Fuel Price Forecasts (at Constant 2012 Prices)

		2012	2020	2025	2030	2035
Crude Oil						
Current policies	$/bbl	109	120	127	136	145
New policies	$/bbl	109	113	115	121	128
450 scenario	$/bbl	109	110	107	104	100
Coal						
Current policies	$/ton	99	112	116	118	120
New policies	$/ton	99	106	109	110	110
450 scenario	$/ton	99	101	95	86	75

$/bbl = dollar per barrel, $/ton = dollar per ton.

Source: International Energy Agency. 2013. *World Energy Outlook 2013*. Paris. Table 1.4. Prices are for average imports to the Organisation for Economic Co-operation and Development countries.

[20] International Energy Agency. 2013. *World Energy Outlook 2013*. Paris.

The resulting macroeconomic and fuel price forecasts are as shown in Table 4.2.

Table 4.2: Macroeconomic and Fuel Price Forecasts

		Price level	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	OECD inflation	[]		0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
2	OECD deflator			1.000	1.025	1.051	1.077	1.104	1.131	1.160	1.189
3	US PPI	[]		0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
4	Indonesia Inflation	[]		0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.045
5	Exchange rate	Rp/$		11500	11724	11953	12186	12424	12667	12914	13166
6	Domestic Rp deflator	[]		1.00	1.05	1.09	1.14	1.19	1.25	1.30	1.36
7	**Oil prices**										
8	IEA Oil	2012 $/ton	109	110	112	113	114	116	117	119	120
9	Annual growth rate	[]		1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
10	Indonesia	2013 $/bbl		100	101	102	104	105	106	107	109
11	@nominal prices	nominal $/bbl		100	104	108	112	116	120	125	129
12	MFO	nominal $/bbl		90	93	97	100	104	108	112	116
13	**Coal prices**										
14	IEA coal	2012 $/ton	99	100.5	102.1	103.7	105.3	106.9	108.6	110.3	112.0
15	Annual growth rate	growth []		1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
16	@2103 prices	2013 [$/ton]		100	102	103	105	106	108	110	111
17	Indonesian Coal Index	2013 [$/ton]		78	79	80	82	83	84	86	87
18	Nominal	nominal [$/ton]		78	81	85	88	92	95	99	103

$/bbl = dollar per barrel, $/ton = dollar per ton, IEA = International Energy Agency, MFO = marine fuel oil, OECD = Organisation for Economic Co-operation and Development, Rp = Indonesian rupiah, US PPI = United States Producer Price Index.
Source: IEA coal and oil prices from the International Energy Agency. 2013. *World Energy Outlook 2013*. Paris.

Assumptions:
Indonesia crude oil forecast for 2012 as from last available Rencana Usaha Penyediaan Tenaga Listrik (RUPTL) (Electricity Power Supply Business Plan). This price is escalated at the same rate as the IEA oil price forecast. The basis is assumed to be the average price of the Organization of the Petroleum Exporting Countries (OPEC) Reference Barrel. At the time of writing (mid 2014) the actual OPEC reference barrel stands at around $100/bbl, so the assumed (Indonesia) price of $101/bbl is reasonable.

Organisation for Economic Co-operation and Development (OECD) and US PPI inflation by assumption, reflecting consensus forecasts. Exchange rate adjust according to the ratio of OECD and Indonesia inflation. Marine fuel oil price as 90% of world oil price from PLN RUPTL. Indonesia inflation is taken as the midpoint of the current Bank of Indonesia inflation target for 2014 of 4.5+1%.

4.4 Avoided Fixed Costs

The calculation of fixed costs for coal and oil projects is shown in Table 4.3. Investment cost recovery depends on assumptions about debt to equity ratio (30% equity), the cost of PLN equity (assumed here at 14%), and the cost of debt (7%).[21] The assumptions for overnight capital costs and fixed O&M are from PLN's RUPTL.

[21] Equivalent to a WACC of 9.1%.

Table 4.3: Fixed Costs (Investment Recovery and Fixed Operation and Management)

				Java and Sumatra, large coal	Eastern Islands, small coal	Oil
1	Overnight cost		$/kW	1,400	1,760	700
2	Development costs		$/kW	150	200	50
3	Interest during construction		$/kW	291	287	81
4	Total financial cost		$/kW	1841	2,247	831
5	Equity	0.3[a]	$/kW	552.3	674.2	249.2
6	RoE		[ ]	0.14	0.14	0.14
7			$/kW	77.3	94.4	34.9
8	Debt		$/kW	1289	1573	581
9	Cost of debt	0.07[b]	$/kW/year	90.2	110.1	40.7
10	Fixed O&M cost		$/kW/year	35.0	61.3	55.0
11	Total fixed cost/year		$/kW/year	202.5	265.8	130.6
12	Assumed PLF		[ ]	0.80	0.60	0.60
13	Generation[c]		hours/year	7008	5256	5256
14	Total fixed cost		US¢/kWh	2.9	5.1	2.5

$/kW = dollar per kilowatt-hour, O&M = operation and maintenance, PLF = plant load factor, RoE = return on equity, US¢/kWh = cents per kilowatt-hour.

Notes:
[a] Assuming 30% equity (70% debt)
[b] Cost of debt (interest rate)
[c] Equivalent to kWh per year per kW of installed capacity

Source: Authors' calculations based on data from *PT Perusahaan Listrik Negara* (State Electricity Company) (PLN).

Actual costs of large new coal projects using supercritical and ultra-supercritical technology show considerable variation, with completed costs ranging from $1,300/kW for the 600 MW Cirebon supercritical project to $2,240/kW for the 1,000 MW ultra-supercritical project at Indramayu.[22]

4.5 Avoided Variable Costs

The variable fuel costs are shown in Table 4.4. Costs per kWh of small coal projects are 50% greater than large projects in large part because of significantly higher transportation costs (30%–50% greater per ton), and much lower heat rates. A discussion of calculating depletion premiums for Indonesian coal follows in Stakeholder Comment 2 and Box 4.

[22] Indramayu is financed by JICA (http://www.mofa.go.jp/mofaj/gaiko/oda/data /zyoukyou/h23/y110818_1.html). The 1,000 MW ultra-supercritical Manjung 4 project in Malaysia (ASEAN's first ultra-supercritical project) has a total project cost of $1,600/kW (but this is a project at an existing site with much of the infrastructure in place).

Table 4.4: Variable Costs

				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Coal price		$/ton	78.0	81.2	84.5	88.0	91.6	95.3	99.2	103.3	106.6	110.1	113.6	117.3
2	Growth rate		[ ]		4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	3.2%	3.2%	3.2%	3.2%
3	Reference CV	5900	KCal/kg												
4	Cost, fob		$/million KCal	13.22	13.76	14.32	14.91	15.52	16.16	16.82	17.51	18.07	18.65	19.25	19.87
5	Cost, fob		$/million BTU	3.32	3.46	3.60	3.75	3.90	4.06	4.23	4.40	4.54	4.69	4.84	4.99
6	**Large Coal**														
7	Transport to Java		Rp/ton	130840	PLN estimate										
8	Heat value		KCal/kg	4200	PLN estimate										
9	Cost per ton		$/ton	13.35	13.95	14.58	15.24	15.92	16.64	17.39	18.17	18.99	19.84	20.73	21.67
10	Cost per million BTU		$/million BTU	0.80	0.83	0.87	0.91	0.95	1.00	1.04	1.09	1.14	1.19	1.24	1.30
11	Java coal cost		$/million BTU	4.12	4.29	4.47	4.66	4.85	5.05	5.27	5.49	5.68	5.87	6.08	6.29
12	Heat rate	38.5%	BTU/kWh	8,862	8,862	8,862	8,862	8,862	8,862	8,862	8,862	8,862	8,862	8,862	8,862
13	Variable fuel cost		US¢/kWh	3.65	3.80	3.96	4.13	4.30	4.48	4.67	4.86	5.03	5.21	5.39	5.57
14	Variable O&M cost		US¢/kWh	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
15	Total variable cost		US¢/kWh	3.85	4.00	4.16	4.33	4.50	4.68	4.87	5.06	5.23	5.41	5.59	5.77
16	**Small coal, isolated grids, small islands**														
17	Transport to typical island		Rp/ton	250000	PLN estimate										
18	Heat value		KCal/kg	4200	PLN estimate										
19	Cost per ton		$/ton	25.51	26.66	27.86	29.11	30.42	31.79	33.22	34.72	36.28	37.91	39.62	41.40
20	Cost per million BTU		$/million BTU	1.53	1.59	1.67	1.74	1.82	1.90	1.99	2.08	2.17	2.27	2.37	2.48
21	Eastern coal cost		$/million BTU	4.85	5.05	5.27	5.49	5.72	5.96	6.21	6.48	6.71	6.95	7.21	7.47
22	Heat rate	25.6%	BTU/kWh	13,333	13,333	13,333	13,333	13,333	13,333	13,333	13,333	13,333	13,333	13,333	13,333
23	Variable fuel cost		US¢/kWh	6.464	6.74	7.02	7.32	7.63	7.95	8.28	8.63	8.95	9.27	9.61	9.96
24	Variable O&M cost		US¢/kWh	0.200	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
25	Total variable cost		US¢/kWh	6.66	6.74	7.02	7.32	7.63	7.95	8.29	8.64	8.95	9.27	9.61	9.96
26	**Oil, isolated grids, small islands**														
27	Fueloil, HSD	1.125	dollar per barrel	113	114	115	117	118	119	121	122	124	125	127	128
28	Cost per million BTU	0.1667	$/million BTU	18.75	18.98	19.21	19.44	19.68	19.92	20.16	20.40	20.63	20.87	21.11	21.35
29	Assumed heat rate	34.0%	BTU/kWh	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037
30	Variable fuel cost		US¢/kWh	18.82	19.05	19.28	19.51	19.75	19.99	20.23	20.48	20.71	20.94	21.18	21.43
31	Variable O&M cost		US¢/kWh	0.200	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
32	Total variable cost		US¢/kWh	19.02	19.05	19.28	19.52	19.75	19.99	20.23	20.48	20.71	20.95	21.19	21.43

$/bbl = dollars per barrel, $/KCal = dollars per kilocalorie, $/million BTU = dollars per million British thermal units, $/million KCal = dollars per million kilocalories, $/ton = dollars per ton, BTU = British thermal unit, BTU/kWh = British thermal unit per kilowatt-hour, CV = calorific value, fob = free on board, HSD = high speed diesel, KCal/kg = kilocalorie per kilogram, O&M = operation and maintenance, Rp/ton = rupiah per ton.

Notes:
(1) The coal transportation cost provided by PLN for eastern islands ranges from 185,900 Rp/ton (for the Ende project, Flores Island), 455 nautical miles (NM), to 292,300 Rp/ton for other small eastern island projects (Ternate) where distances are around 935 NM. 250,000 Rp/ton is taken here as a representative figure.
(2) Heat rates for small coal projects are very poor. PLN data for the Ende project (2 x 7 MW) is 14,507 BTU/kWh (23.5% efficient); for 2x 25 MW, PLN estimates 25.6% efficiency, compared to 37% for large coal modern projects.

Source: Authors' calculations.

Stakeholder Comment 2: Depletion Premium

Comment:

The calculation of avoided fuel cost does not include a depletion premium.[a] Given that Indonesia's coal resources are finite, might it not be better to keep our coal in the ground and use it for power generation when its value is much higher?

Reply:

Depletion premiums are significant where a resource is priced at its current or historical domestic extraction cost (as its long run marginal cost), and where the so-determined domestic price is significantly below the international price. This a major issue in many ASEAN countries in the case of gas: in Viet Nam,

continued on next page

Stakeholder Comment 2 *continued*

for example, domestic gas for power generation is priced at around $3.5/million British thermal units (BTU), and the known domestic resource will be exhausted in another 15–20 years, absent new discoveries—at which point Viet Nam would have to face a gas price at international levels of $12/million BTU or more. In such a case the current domestic price should indeed be adjusted to include a depletion premium.

However, in the case of Indonesian supplies to PLN, coal is now already priced at its international level and there are significant exports. Therefore, whether Indonesian coal is better left in the ground today in the expectation of a higher price tomorrow depends on an assessment of future prices of internationally traded coal, and how much coal there is in Indonesia. Indeed, in one scenario considered in the most recent International Energy Agency, World Energy Outlook, the coal price declines (see Table 4.1)—in which case the rational policy would be to export as much coal at the currently higher price as possible!

Box 4 discusses the problems of practical calculation of the depletion premium for Indonesian coal.

[a] For a more technical explanation of the depletion premium for an exhaustible resource, see, e.g., ADB. 1997. *Guidelines for the Economic Analysis of Projects*. Manila. Appendix 6.

Source: Stakeholder Discussions.

Box 4: Depletion Premium for Indonesian Coal

The depletion premium is the amount equivalent to the opportunity cost of extracting the resource at some time in the future, above its economic price today (and should be added to the economic cost of production today). It is defined as follows:[a]

$$DP_t = \frac{(PS_T - CS_t)(1 + r)^t}{(1 + r)^T}$$

where

t	=	year
T	=	year to complete exhaustion
PS_T	=	price of the substitute (internationally traded coal) at the time of complete exhaustion.
CS_t	=	price of the domestic resource in year t
r	=	discount rate

The main problem in calculating the value of the premium is the uncertainty about when the resource is exhausted, because the exploitable size of a resource is a function of its market value and the cost (and technology) of extraction. Assessment of reserves can change very rapidly—as illustrated by the dramatic developments in gas and oil extraction technology in the US (fracking). If the international cost of coal increased, then doubtless additional resources would be discovered (or become economic) in Indonesia.

Indonesia is the world's number one coal exporter, having overtaken Australian exports in 2005, so the question of when Indonesian coal reserves will be depleted is controversial. According to Ministry of Energy and Mineral Resources data, current remaining reserves (of all rank) are 21 billion tons, which at 2014 production of 342 million tons, would be depleted in 61 years. For high rank coals (>6,100 Kcal/kg), reserves are only 2.6 billion tons but 2014 production is expected at 114 million tons, so depletion in 22 years.[b] A more pessimistic assessment is the 2013 BP Statistical Review of World Energy,[c] which assesses Indonesian coal reserves at 5.5 billion tons, which could be exhausted in as little as 14–15 years. However, total *global* reserves are 861 billion tons, enough for more than 100 years.

[a] See, ADB. 1997. *Guidelines for the Economic Analysis of Projects*. Manila. Appendix 6, Depletion Premium.
[b] Government of Indonesia, Ministry of Energy and Mines. 2011. *Domestic Market Obligation of Coal Policy in Indonesia*. Jakarta. Directorate of Coal Business Enterprise.
[c] British Petroleum. 2013. BP Statistical Review of World Energy. June 2013. www.bp.com/statisticalreview

4.6 Avoided Global Externalities

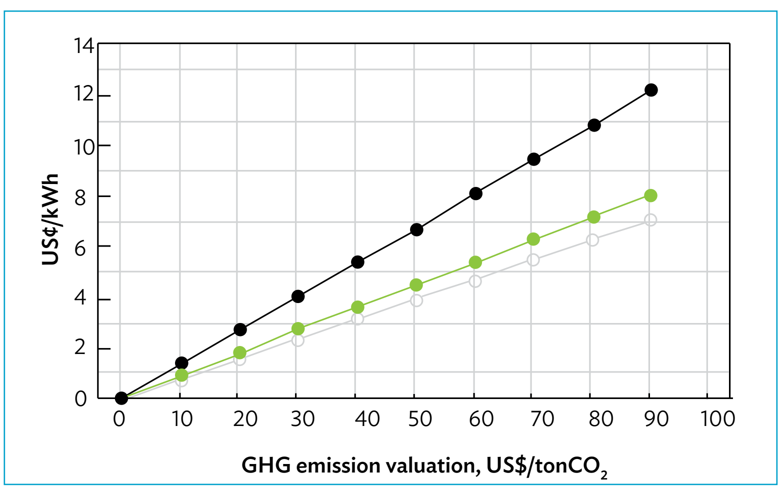
The basis for the avoided global externality benefit should not be the current market price for CO_2 in global carbon markets (which is a financial price that is also highly volatile), but should be the economic price, namely the so-called global social cost of carbon (GSCC) (Box 5).

Since most geothermal projects in Indonesia benefit from concessionary finance offered by the global community, it is reasonable that the value of avoided GHG used in the tariff calculation is consistent with typical valuations used by the World Bank and ADB, currently around \$30/ton CO_2. This idea is not entirely new to the Government of Indonesia, as discussed in Box 6.

As shown in Table 4.5, the valuation in US¢/kWh will depend on the fuel and the heat rate. At \$30/ton CO_2, this ranges from 3.64 US¢/kWh in the inefficient small coal projects to 2 US¢/kWh for oil.

Table 4.5: Impact of Greenhouse Gas Valuations

		Large coal	Small coal	Oil
		US¢/kWh	**US¢/kWh**	**US¢/kWh**
IPCC default	kg/GJ	96.1	96.1	74.1
	efficiency	0.39	0.26	0.34
Heat rate	kJ/kWh	9,351	14,068	10,590
	kg/kWh	0.899	1.352	0.785
$/ton	0	0.00	0.00	0.00
	10	0.90	1.35	0.78
	20	1.80	2.70	1.57
	30	2.70	4.06	2.35
	40	3.59	5.41	3.14
	50	4.49	6.76	3.92
	60	5.39	8.11	4.71
	70	6.29	9.46	5.49
	80	7.19	10.82	6.28
	90	8.09	12.17	7.06



CO_2 = carbon dioxide, GHG = greenhouse gas, GJ = gigajoule, IPCC = Intergovernmental Panel on Climate Change, kg = kilograms, kJ = kilojoules, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

Box 5: Global Social Cost of Carbon

The literature on the global social cost of carbon (GSCC) is growing, with estimates ranging from a small net benefit to costs of several hundred dollars a ton. Thus almost any estimate would find some support. Tol's 2008 meta-analysis of the peer-reviewed literature,[a] which updated an earlier 2005 meta analysis,[b] cites 211 studies, and found an average estimate of $120/ton carbon ($33/ton carbon dioxide [CO_2]) for studies published in 1996–2001, and $88/ton carbon ($24/ton CO_2) for studies published since 2001.

Much of the economics literature on the subject is highly technical, particularly with respect to the choice of discount rate and assumptions about future global economic growth and income inequalities: in general one can say that the lower the discount rate, the higher the social cost of carbon (a value that may also change over time). The high valuation of the Stern Review (*"the current social cost of carbon might be around $85/ton CO_2"*)[c] is largely a consequence of the use of a very low discount rate.[d] The 2007 Intergovernmental Panel on Climate Change report highlighted the wide range of values of the GSCC in the literature as being in the range of $4/ton CO_2–$95/ton CO_2.

Carbon Valuations in World Bank Studies and Project Appraisals

Country	$/ton CO_2	Study	Reference
India	32	Policy study (2010)	G. Sargsyan et al (2011) *Unleashing the Potential of Renewable Energy in India,* World Bank (2011)
Viet Nam	30	Trung Son hydro project	World Bank Project Appraisal Document (2010)
South Africa	29	Medupi coal project	World Bank Project Appraisal Document (2011)
Morocco	30	Ourzazate I CSP	World Bank Project Appraisal Document (2011)

Source: Authors' calculations.

In the United States, regulatory impact analysis requires consideration of the social cost of carbon,[e] using a range of discount rates (from 2.5% to 5.0%), with values that increase over time. For example, at a 5.0% discount rate the valuation is $12/ton in 2015, rising to $27/ton by 2050; at a 2.5% discount rate the valuation rises from $58/ton to $98/ton by 2050. In 2007, the Government of the United Kingdom's Department of the Environment recommended a value of £25/tonCO_2 ($37/ton);[f] this was subsequently updated to a time-dependent system ranging from £23/ton CO_2 in 2015 rising to £48/ton by 2025 ($36/ton CO_2–$76/ton CO_2).

Notes:

[a] R. Tol. 2008. The Social Cost of Carbon: Trends, Outiers and Catastrophes. *Economics E-journal*. 2008–25. 12 August.

[b] R. Tol. 2004. The Marginal Damage Costs of Carbon Dioxide Emissions: An Assessment of the Uncertainties. *Energy Policy*. 33 (2005), pp. 2064-2074.

[c] Government of the United States, Interagency Working Group on Social Cost of Carbon. 2013. *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866*. Washington, DC.

[d] R. Price, S. Thornton, and S. Nelson. 2007. The Social Cost of Carbon and the Shadow Price of Carbon. *Defra Evidence and Analysis Series.* Government of the United Kingdom, Department for Environment, Food and Rural Affairs (DEFRA); Government of the United Kingdom, Department of Energy & Climate Change. 2009. *Carbon Valuation in UK Policy Appraisal: A Revised Approach*. London.

[e] N. Stern. 2007. *Stern Review on the Economics of Climate Change*. Cambridge University Press. p. 304.

[f] For a good discussion of these issues, and a review of the assumptions in the Stern Review, see, for example, C. Hope and D. Newbery. 2007. *Calculating the Social Cost of Carbon*. Cambridge University Electricity Policy Research Group; M. Grubb, T. Jamasb, and M. Pollitt (eds). 2008. *Delivering a Low Carbon Electricity System: Technologies, Economics and Policy*. Cambridge University Press.

Stakeholder Comment 3: Greenhouse Gas Valuation

Comment:

Why should Indonesia bear the cost of greenhouse gas (GHG) emission reductions? Under the Kyoto Protocol, Indonesia is not an Annex 1 country, and is not therefore obliged under the treaty to reduce its GHG emissions.

Reply:

That is correct. But there are several arguments why it may be wise to show goodwill in this matter, even if not mandated by international treaty.

- Recognizing the strong increase in GHG emissions due to increased coal use, and as a responsible global citizen, Indonesia has made public commitments to reduce its GHG emissions.
- When funding geothermal projects, global climate funds and the multilateral development banks through which they are usually routed generally require commitments to reduce GHG emissions, and an implicit or explicit valuation of these benefits.
- Even if there are other reasons for Indonesia to develop its geothermal resources, particularly if these are difficult to value, reducing GHG emissions serves as a useful general proxy indicator for environmental quality.

Comment:

Even if it were true that GHG emission reduction did constitute a benefit to Indonesia, the proposed \$30/ton CO_2 is very high. Why should Indonesia value GHG emissions at \$30/ton CO_2 if the carbon price on global carbon markets is currently just \$5/ton?

Reply:

It is indeed for the Government of Indonesia, and not a technical consultant or international financial institutions, to determine what value Indonesia should assign to the avoidance of GHG emissions. Table 4.5 is offered as guidance to show the relationship between that assumption in \$/ton CO_2, and the potential impact on the tariff ceiling.

Prior to the final issuance of the tariff, it is suggested that the Ministry of Finance and the Ministry of Energy and Mineral Resources, in consultation with the designated national authority under the Kyoto Protocol, discuss the matter to decide on the final value.

Note that this valuation of the GSCC is unrelated to any financial benefit that may accrue to the developer from the sale of carbon credits under the Clean Development Mechanism (or any successor to it). The GSCC is included in the calculation of the avoided cost ceiling regardless of whether the developer benefits from any carbon revenue—which should be to his benefit (although subject to whatever taxes are levied by the designated national authority on sales of Certified Emission Reduction [CER)] and any income tax levied on the additional profit derived from their sale). Most countries with standardized PPAs for renewable energy stipulate that any carbon sales revenue that may be collected by the developer are for the developer to keep, and does not reduce the tendered price.

It may be supposed that this raises the potential issue of double counting: since the avoided cost of GHG emissions is already included in the tariff ceiling (and paid for by government in the higher tariff), should not any CER credits revenue accrue to the government rather than the developer? However, there are several reasons why CER revenue should accrue to the developer:

(i) If the CER revenue accrues to government, there is no incentive for a developer to incur the significant transaction costs of Clean Development Mechanism registration.

(ii) At the time of tender it is hard to gauge what CER revenue would actually be realized, so many years in advance.

(iii) Even if the ceiling price includes the avoided cost of GHG emissions, this is only the ceiling price—bid prices may be significantly lower.

In any event, even if CER revenue were viewed as a windfall, government recaptures a share of that revenue through the corporate income tax. Indeed, under the proposed sharing of CER revenue in the current PPA template (50% to the developer, 50% to PLN), in fact (at the margin) the government collects another 30% of the developers 50% share (corporate income tax), so the total that accrues to the developer is just 35%, from which must be deducted the substantial transaction costs of Clean Development Mechanism registration. Given that, at least under present conditions in global carbon markets, a forecasted revenue stream for future CER sales is unlikely to be bankable, it is unclear that a 50/50 sharing of such revenues would provide much incentive for developers to actively pursue carbon sales.

Box 6: Ministry of Finance Green Paper

The proposition that Indonesia should be willing to pay the true avoided cost for geothermal energy is not new. The 2009 Ministry of Finance Green Paper on strategies for climate change mitigation proposed that a reasonable and conservative estimate of the actual "true cost of electricity" incurred by the Government of Indonesia is $0.13/ kilowatt-hour (kWh), derived on the basis of adding the cost of local air pollution damage costs and a carbon price to the "book cost" paid by *PT Perusahaan Listrik Negara* (State Electricity Company).

Green Paper Estimate of True Cost of Electricity

	$/kWh
Capital cost	$0.054
Operating cost	$0.007
Fuel cost	$0.029
Fuel price cost risk	$0.010
Carbon cost	$0.020
Air pollution and other externalities	$0.010
Total	$0.130

Source: Government of Indonesia, Ministry of Finance, *Green Paper: Economic and Fiscal Policy Strategies*. Table 4.

The basis for the carbon price component was a value of $20/ton CO_2. The report also argues for a carbon tax set at Rp80,000/ton (about $8/ton CO_2) to be levied across the entire economy—for which macroeconomic modeling showed a slight increase in gross domestic product. The report notes the commitment made by the President of Indonesia at the 2009 Group of 20 meeting to reduce emissions by 26% by 2020, and up to 41% with international help. The Green Paper analysis shows that a $30/ton CO_2 levy would achieve such a target. In short, the $30/ton CO_2 valuation proposed for the geothermal tariff is consistent with previous Ministry of Finance assessments.

Source: Government of Indonesia, Ministry of Finance. 2009. Green Paper: Economic and Fiscal Policy Strategies for Climate Change Mitigation in Indonesia, Ministry of Finance and Australia Indonesia Partnership, Jakarta.

4.7 Local Environmental Externalities

It is widely acknowledged that fossil fuel combustion also results in local environmental impacts, particularly from the local air emissions (NOx, SOx, and particulates). However, the valuation of the damages is controversial, because the main share of the impact is human health, which in turn depends on monetization of mortality and morbidity. The Castlerock Report has argued for inclusion of these costs in any avoided cost tariff.

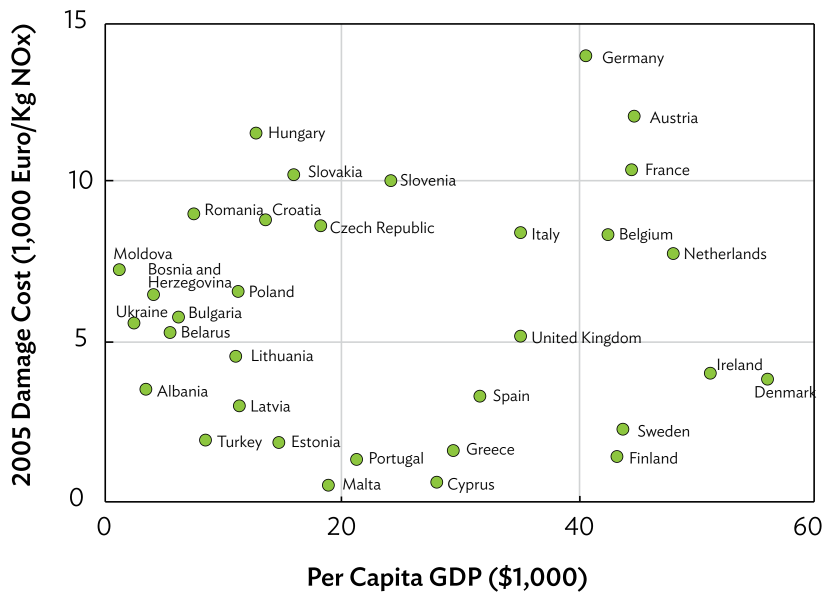
Many estimates are based on aggregate damage costs per kWh. But damage costs are a function of location and affected population, of pollution control technology in place, fuel characteristics, weather patterns (particularly on islands), and stack height. Aggregate $/kWh assessments therefore have little credibility.

Most comprehensive studies are for European Union and/or Europe and the US, which for a number of reasons are difficult to extrapolate to developing countries. The most common method is to scale impacts by per capita gross domestic product (GDP) (the so-called "benefit-transfer" method). However, this method does not work within the European Union, so there is even less reason to think it would work across the entire globe. Figure 4.1 shows the relationship between per capita GDP and one component of damage costs (in €/kg NOx emissions).

The lack of correlation is self-evident, testimony to the fact that damage costs are a function of a wide range of factors, including local climate and weather patterns (in a country such as Indonesia, with many islands subject to monsoonal climate, much of the local pollution is blown out to sea), lifestyles (in the US, people spend a much greater proportion of their time indoors than in developing countries), and health status (poor populations in developing countries tend to have a lower level of health than their counterparts in the US and Europe, and are therefore more susceptible to pollution-related illness).

Notwithstanding these problems, several such estimates have been used in Indonesian renewable energy project appraisals. For example, the 2011 Project Appraisal Document for the Geothermal Clean Energy Investment Project used a value of health damage costs of $0.00546/kWh in its economic analysis (Table 4.6). A recent assessment of the local environmental damages from Indonesian thermal generation projects is further discussed in Box 7.

Figure 4.1: Nitrogen Oxide Damage Costs versus Per Capita Gross Domestic Product, European Union



GDP = gross domestic product, NOx = nitrogen oxides.

Source: Data from European Environment Agency. 2011. Revealing the Costs of Air Pollution from Industrial Facilities in Europe. *EEA Technical Report* No. 15/2011. Luxembourg.

Box 7: Damage Cost Estimates for Indonesia

The most recent assessment of the local environmental damage costs from Indonesian thermal generation projects appears to be Kusumawati et al.,[a] who studied damage costs at the Paiton coal project, the Gresik gas project, and the *Muara Karang* oil project. These projects have emission factors for the main criteria pollutants as follows:

Emission Factors (Gram/kWh)

Project	SO_2	NO_2	PM10
Paiton Coal	4.34	4.56	0.67
Muara Karang Oil	11.7	2.32	0.29
Gresik Gas	0	1.79	0

kWh = kilowatt-hour, NO_2 = nitrogen dioxide, SO_2 = sulphur dioxide, PM10 = particulate matter less than 10 micrometers in diameter.

Source: W. Kusumawati, A. Sugiyono, and J. Bongaerts. 2010. Using the QUERI Model-AirPacts Program to Assess the External Costs of Three Power Plants in Indonesia with Three Different Energy Sources. *IMRE Journal.* 4 (1).

Using the SIMPACT model, damage costs per kWh were estimated as follows:

Damage Costs, US¢/kWh (at 2010 Price Levels)

	Gresik	Muara Karang	Paiton
	Gas	HFO	Coal
PM10	0	1.301	0.207
SO_2	0	0.517	0.016
NO_2	0.051	0.063	0.008
Sulfates	0	0.148	0.042
Nitrates	0.036	0.173	0.045
Total	0.087	2.202	0.318

HFO = heavy fuel oil, kWh = kilowatt-hour, NO_2 = nitrogen dioxide, SO_2 = sulphur dioxide, PM10 = particulate matter less than 10 micrometers in diameter.

Source: W. Kusumawati, A. Sugiyono, and J. Bongaerts. 2010. Using the QUERI Model-AirPacts Program to Assess the External Costs of Three Power Plants in Indonesia with Three Different Energy Sources. *IMRE Journal.* 4 (1).

These damage cost estimates differ slightly to those estimated by Liun et al.[b] who use the same SIMPACT model as Kusumawati.

Damage Costs, US¢/kWh (at 2010 Price Levels) By Data Source

	Gresik	Muara Karang	Paiton	Surabaya	Tanjung Jati
	Gas	HFO	Coal	Coal	Coal
Kusumawati (2010 prices)	0.087	2.202	0.318		
Liun et al (2007)	0.074			0.097	0.646

HFO = heavy fuel oil, kWh = kilowatt-hour.

Both Kusumawati et al (2010) and Liun et al. (2007) use US damage cost estimates adjusted by purchase power parity-adjusted per capita GDP. Thus, none of these estimates can be considered reliable,[c] and at best are indicative of order of magnitude.

Notes:

[a] W. Kusumawati, A. Sugiyono, and J. Bongaerts. 2010. Using the QUERI Model-AirPacts Program to Assess the External Costs of Three Power Plants in Indonesia with Three Different Energy Sources. *IMRE Journal.* 4 (1).

[b] E. Liun, A. Kuncoro, and E. Sartono. 2007. *Environmental Impacts Assessment of Java's Electricity Generation Using SimPacts Model.* International Conference on Advances in Nuclear Science and Engineering. pp. 379–384.

[c] Indeed, none of these various studies appear in the peer-reviewed literature.

Table 4.6: Estimates of Local Health Damage Costs in Indonesia as Compared with the People's Republic of China (2000 US¢/kWh)

	Suralaya	People's Republic of China
TSP	N/a	0.103
SOx	N/a	0.018
NOx	N/a	0.000
Total	0.20–0.65	0.121

N/a = not available, NOx = nitrogen oxides, SOx = sulphur oxides, TSP = total suspended particulates, US¢/kWh = cents per kilowatt-hour.

Source: World Bank. 2011. *Geothermal Clean Energy Investment Project. Project Appraisal Document*. Washington, DC.

However, both the People's Republic of China and Suralaya studies cited in this table used benefit transfer estimates from the US. The Castlerock report also quotes a study at Paiton—but this again suffers from the same problem.

For project appraisal the recommended approach is to use the methodology proposed by the World Bank Environment Department, where damage costs are related to kg of emissions and stack height (Table 4.7).

Table 4.7: Damage Cost of Local Air Pollutants (expressed as $/ton of pollutant per $1,000 of per capita GDP per million population)

	Utility, High Stack	Medium Stack, Large Industry	Self Generation
PM10	42	214	3,114
SO_2	6	33	487
NOx	2	9	123

$/ton = dollars per ton, NOx = mono-nitrogen oxide, PM10 = particulate matter less than 10 microns in diameter, SO_2 = sulfur dioxide.

Source: K. Lvovsky et al. 2000. *Environmental Costs of Fossil Fuels: A Rapid Assessment Method with Application to Six Cities.* Washington, DC: World Bank.

However, while this approach is suitable for assessing a single proposed project, it is difficult to apply to derive a credible "average" tariff premium estimate. In systems with high, unserved energy demand, the main local health impact is from diesel self-generation sets, with uncontrolled emissions in densely populated areas at ground level—two orders of magnitude greater than a utility project with modern pollution controls, high stack, and relatively remote locations.

Conclusions

Based on this discussion, we find as follows:

- Until there is a credible health damage assessment conducted for Indonesia, which is based on local epidemiological and health data, valuations of the local environmental impact based on the benefit transfer method are unreliable and not credible.
- A *de minimus* charge of $0.001/kWh may be included, in recognition that the avoided environmental impacts are not zero, and as a placeholder for possible future inclusion, but $0.005/kWh as proposed by Castlerock has no rational basis.[23]
- For a 2020 geothermal target of 4,000 MW, the potential impact of such a *de minimus* charge on PLN's purchase costs is negligible.[24]

[23] The Viet Nam regulator rejected a local environmental impact charge for the avoided cost tariff for renewable energy on similar grounds: until a peer-reviewed Viet Nam-specific health damage study was available, any estimate was deemed to be arbitrary and lack credibility.

[24] This follows from the relative magnitude compared to GHG valuations. At $30/ton, the tariff impact is 2.4 US¢/kWh, compared to 0.1 US¢/kWh for local environmental impacts (about 4%): it follows that the impact of local externalities on the PLN subsidy would be no more than a few million US dollars.

4.8 Premium for Price Volatility

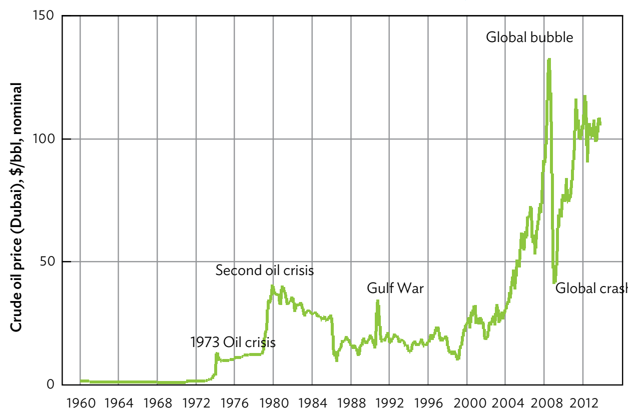
The Castlerock report first argued that fossil fuel price volatility should be factored into an avoided cost tariff for geothermal energy.[25] However, the calculations in that report reflect not price volatility (as that term is normally understood) as much as a hedge against long-term price increases. But the avoided production costs will already reflect the impact of higher fossil prices, if they occur. Fuel price volatility as used in our report means fluctuations around the long-term trends.

Fuel price volatility is of particular concern to MoF, because fuel costs account for a major portion of the total PSO subsidy provided to PLN, and MoF must budget these funds. Sudden and unforeseen price increases can create great difficulty in fiscal management as additional funds then require mobilization. On the other hand, a sudden decrease in price can result in unused funds, which might have been spent on other projects (as occurred in the 2008/2009 price collapse). It is worth noting, however, that the biggest shock to the PSO occurred as a consequence of the change in Indonesian domestic coal pricing (coal to PLN is now priced at international market levels, rather than at the previously subsidized price)—a (desirable) policy change unrelated to international market conditions.

Oil

Figure 4.2 shows the nominal price of crude oil (Dubai) since 1960. One observes short-lived price spikes (as observed in 1990/1991 at the time of the first Gulf War); major step changes (in 1973, first oil embargo); prolonged deviations from trends, such as the period of high prices between 1979 (Iranian revolution) and the subsequent collapse in 1986; a global speculative bubble and its dramatic collapse in 2007/2008; and, most importantly, the steady increase in price since 2000 that largely reflects the rise of the People's Republic of China. Smaller regular fluctuations are superimposed around the longer-term trends.

Figure 4.2: World Oil Price, $/bbl



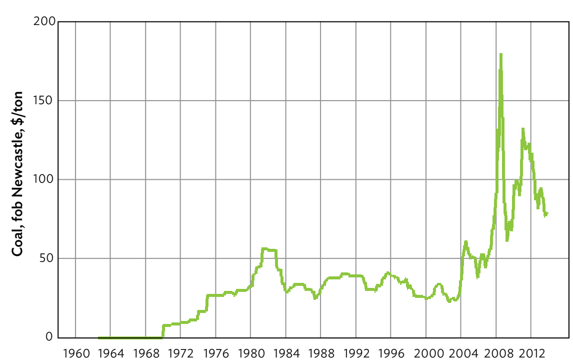
$/bbl = dollars per barrel.

Source: Organization of the Petroleum Exporting Countries (OPEC). 2014. *Annual Statistical Bulletin 2014*. Vienna.

Coal

Short-term price volatility for coal is less than for oil, but still subject to the same general long-term trends in international oil markets, as shown in Figure 4.3.

Figure 4.3: Australian Coal Prices, $/ton



$/ton = dollars per ton, fob = free on board.

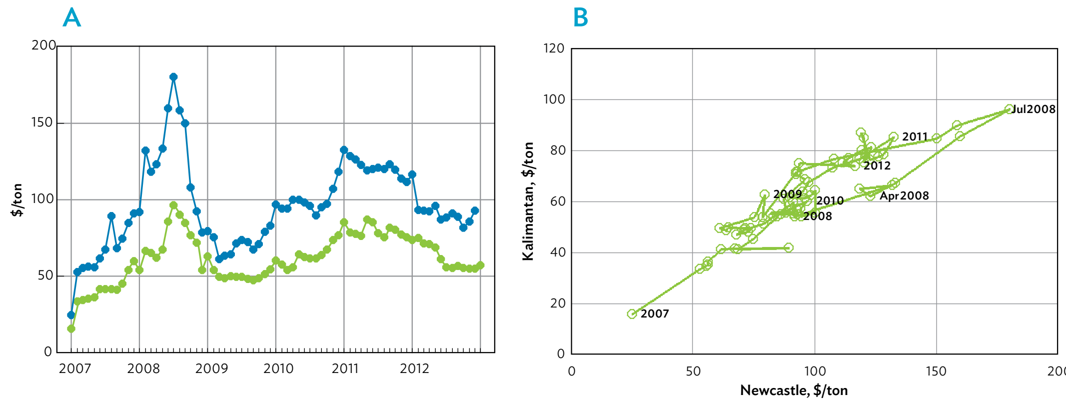
Source: Platts International Coal Reports.

Indonesian coal is also traded on the international markets, with prices that are strongly correlated

[25] Castlerock. 2010. *Phase 1 Report.*

to Australian export coal that dominates the Asia–Pacific coal trade (Figure 4.4A). Only in 2008 did Kalimantan coal prices diverge (fall below) significantly from the generally stable relationship, as evident from Figure 4.4B. Indonesia coal futures are offered on a number of international commodity markets, which could be used to hedge short-term volatility.

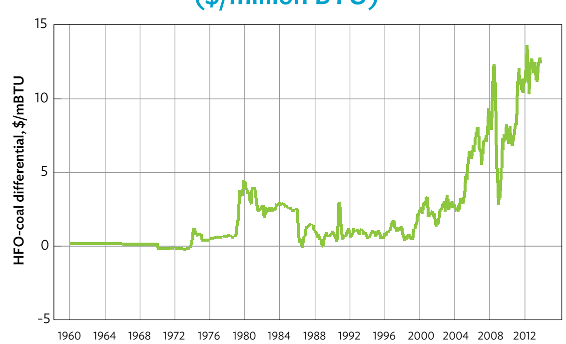
Figure 4.4: Kalimantan Coal Prices



$/ton = dollars per ton.
Source: Platts International Coal Reports.

The urgency for PLN to reduce its reliance on fuel oil is clear from Figure 4.5, which shows the differential between coal and fuel oil on a BTU basis. Until the 1973 oil crisis, heavy fuel oil (HFO) was only slightly more expensive than coal. In the 1980s, the HFO (and crude oil) price was propped up by Organization of the Petroleum Exporting Countries (OPEC) quotas, but the differential narrowed again in 1986. However, since 2000, the People's Republic of China has become a major importer of oil yet an exporter of coal, so the differential has widened.

Figure 4.5: Heavy Fuel Oil–Coal Price Differentials ($/million BTU)

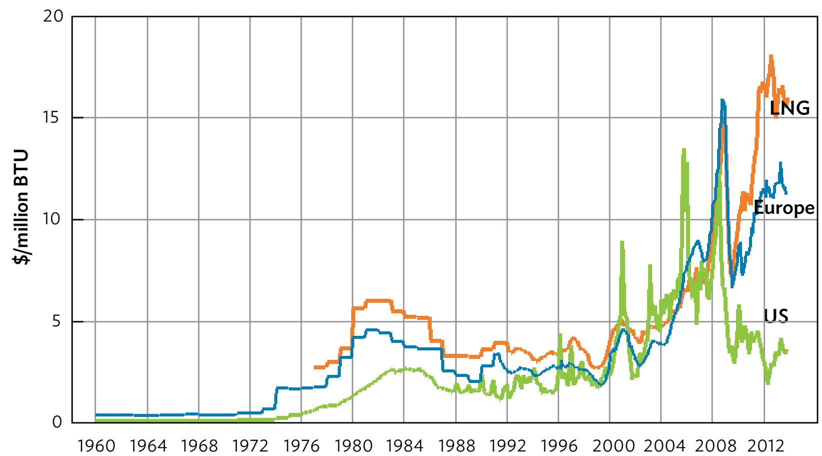


$/million BTU = dollars per million British thermal units, HFO = heavy fuel oil.
Sources: Calculated from data in Platts. 1981-2013. *Platts International Coal Report*. McGraw-Hill Companies Inc. Issues 1-213. London; and Organization of the Petroleum Exporting Countries. 1969–2013. *Bulletin* Vols. I–XLV. Vienna.

Gas

Gas prices, especially in North America, are even more volatile than oil. US Henry Hub gas prices are especially volatile, but Asian LNG prices are less so, a consequence of the past predominance of long term contracts—though the spot market now accounts for a growing share. The potential impact of fracking shale gas in the US has been clearly visible since 2009, with sharp falls in the gas price. Gas prices for the period 1960 to 2012 are shown in Figure 4.6. Most forecasts (IEA, World Bank) also see LNG prices falling from present levels to around $8/million BTU by 2025, as the US joins the ranks of LNG exporters.

Figure 4.6: Gas Prices, $/million BTU

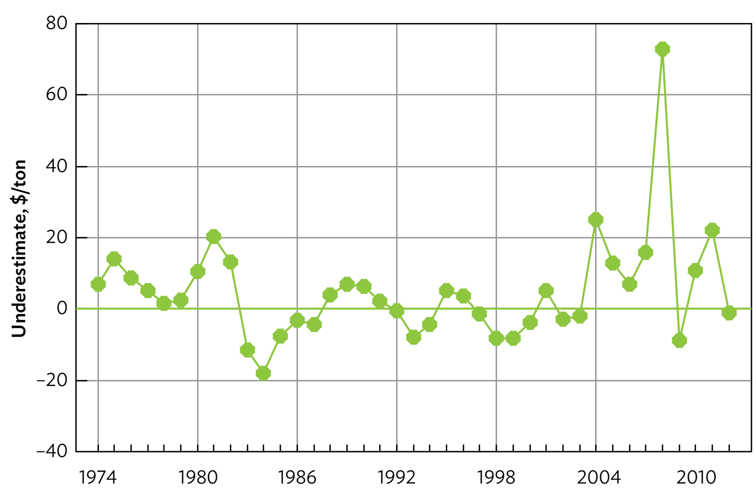


$/million BTU = $/million British thermal units, LNG = liquefied natural gas, US = United States.
Sources: World Bank, US Energy Information Administration.

Forecast Errors

By looking at the historical level of annual price fluctuations, one can calculate the shortfall or surplus to budget for the PSO subsidy from MoF to PLN. There are, obviously, many different forecasting rules, so for illustrative purposes we assume the forecast for year ***n*** is based on the average price of the past 3 years (n-3, n-2, n-1). Figure 4.7 shows the forecasting error using this procedure.

Figure 4.7: Coal Price Forecasting Error, $/ton



$/ton = dollars per ton.
Source: Authors' calculations.

The calculations are shown in Table 4.8. The cost of the forecast error (as an absolute value, with overestimate being equally undesirable as underestimate) is shown in column [4]. With Newcastle coal at 6,300 Kcal/kg and a 2,200 Kcal/kWh heat rate, 0.35 kg of coal are needed per kWh. Therefore, for example, if the error is $25/ton coal (2004), this would translate to 0.87 US¢/kWh. Since the cost of coal is 1.85 US¢/kWh, in 2004 the error is almost 50% of the total.

Table 4.8: Forecast Errors

Year	Actual Newcastle, fob	Forecast	Forecast Error =[1]-[2]	Error as absolute value	Forecast Error	Geothermal Benefit
	$/ton	$/ton	$/ton	$/ton	US¢/kWh	US¢/kWh
	[1]	[2]	[3]	[4]	[5]	[6]
2004	52.9	27.9	25.0	25.0	0.87	1.85
2005	47.6	34.8	12.8	12.8	0.45	1.66
2006	49.1	42.2	6.9	6.9	0.24	1.71
2007	65.7	49.9	15.8	15.8	0.55	2.30
2008	127.1	54.1	73.0	73.0	2.55	4.44
2009	71.8	80.6	–8.8	8.8	0.31	2.51
2010	99.0	88.2	10.7	10.7	0.38	3.46
2011	121.4	99.3	22.1	22.1	0.77	4.24
2012	96.4	97.4	–1.1	1.1	0.04	3.37
2013	84.8	105.6	–20.8	20.8	0.73	2.96
	Average			19.7	0.68	2.85

$/ton = dollars per ton, fob = free on board, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

Conclusions

This permits the following conclusions:

- Since coal is the least volatile of the three main internationally traded fossil fuels, the most important step in reducing Indonesia's exposure to fuel price volatility is to complete the planned shift from HFO to coal as soon as possible.
- Annual coal price volatility has doubled in the last 10 years.
- The 10-year average of the forecast error per ton coal increased from $9.9/ton (in the previous years) to $19.7/ton (Table 4.8), though this latter average includes the 2008–2009 commodity price bubble and its collapse.
- Forecast error per kWh of geothermal energy increased from 0.346 US¢/kWh in the previous years to 0.68 US¢/kWh.
- If the cost to MoF is limited to short-term borrowing, then the tariff premium is much smaller.
- Note that when the price of coal increases as a matter of long-term trend, Indonesia (MoF) already gets the benefit of the higher avoided cost.

4.9 Avoided Cost of Transmission

Opinions vary about who should be responsible for the transmission interconnection, and international best practice suggests no clear answers. Some renewable energy independent power producers (IPPs) would rather be responsible for the interconnection themselves on grounds that this ensures that the line will be built on time and ready for the COD of the generating project.[26] At the same time, given the many delays experienced by geothermal projects, the buyer (i.e., in Indonesia, PLN) is often reluctant to invest its resources in a transmission line only to discover the IPP is not ready.

Transmission interconnection costs are small. As shown in Appendix 2, average costs for geothermal projects (as shown in PLN's RUPTL 2012) are around $50/kW, so with total capital investment of $4,500/kW for typical geothermal generation projects, this will have little impact on the tariff. The same is true for the interconnection costs of thermal projects: for large coal projects in Java, the average is $27/MW.

On balance, we recommend that geothermal project developers be responsible for the construction of the transmission line, but that the tender bid is exclusive of transmission costs. The tariff ceiling would therefore also exclude the avoided costs of connecting fossil fuel projects.

If PLN agrees that the developer incurs the transmission costs, then those costs would be recovered by a nonescalating transmission adder to the tariff to provide recovery of the capital costs over a 10-year period.[27] Given that this will be a very small amount compared to the generation cost, bidders need not compete on this at time of tender. In general we propose that the transmission connection

Sample Calculation: Transmission Adders

Assumptions: 110 MW, 90% annual capacity factor, 867 GWh per year. Developer's transmission line outlays $3 million in year 5, $2 million in year 6. Commercial operation date is 1 January of year 7. Weighted average cost of capital at financial closure is 8.8%.

Net present value at weighted average cost of capital, of the transmission line outlays is $3.2 million. The tariff adder that makes the NPV of the transmission recovery payments equal to this sum is 0.094 US¢/kWh (10 annual payments of $0.81 million).

	NPV	1–4	5	6	7	8	9	10	11	12	13	14	15	16	17
Transmission line ($ million)	3.2		3.00	2.00											
Annual generation (GWh)					867	867	867	867	867	867	867	867	867	867	0
Tariff adjustment (US¢/kWh)					0.094	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Recovery of costs ($ million)	3.2				0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.00
Transmission cost ($/kW)	45.5														

$/kW = dollars per kilowatt, GWh = gigawatt-hour, MW = megawatt, NPV = net present value, US¢/kWh = cents per kilowatt-hour, WACC = weighted average cost of capital.

26 That this is of real concern to developers is shown by the experience of the People's Republic of China, where 20% of all large wind farms currently stand idle for lack of transmission evacuation capacity. Moreover in Indonesia, there were serious delays in providing the transmission lines for the Wayang Windu and Darajat II projects.

27 Under the assumption that PLN is responsible for maintaining the transmission line.

be handed over to PLN on the COD, and that PLN be responsible for transmission O&M (given that the meter is likely to be at the generating plant). Given that these costs will, in general, be quite small compared to the generating project and steam field development, what is important is simply that the proposed transmission arrangements be clearly specified at time of tender.

The calculation is straightforward: the adder is that value that makes the NPV of the stream of transmission line outlays equal to the NPV of the 10 years of tariff recovery payments, that yearly payment being the value of the adder multiplied by the expected annual generation.

4.10 Local Economic Development Benefits

There is much evidence that geothermal project development brings local and regional economic benefits, given that some fraction of the construction and operating cost is spent locally, which boosts local economic activity through multiplier effects. This is recognized in the economic literature in the form of regional income and employment multipliers.

Although we know of no Indonesia-specific employment and regional income multipliers for geothermal and coal projects, there are many studies in the international literature that suggest renewable energy in general, and geothermal energy in particular, is more employment intensive than thermal energy.[28] Typical regional expenditure multipliers are in the range of 1.5 to 2.5, meaning that for every Rp1,000 spent in the local economy, another Rp1,500–Rp2,500 of expenditure is induced (since those additional Rp are in turn spent by the first recipient in making further local purchases).

Thermal projects would have similar multiplier impacts, if not at the power plant site itself, then in coal transportation and mining.[29] However, the literature suggests that these multipliers are much lower than for renewable energy.

We therefore propose that the tariff include a premium for the differential local provincial economic development benefit that accrues from local expenditures on geothermal—so for an average multiplier of 1.5, a differential multiplier of 0.75 for geothermal (meaning that for every Rp1,000 spent locally in a province, another Rp750 of local economic activity will be induced). A discussion about why to use deterministic and not probabilistic calculations is included in the response to Stakeholder Comment 4.

Table 4.9 shows such a calculation. The key assumptions are as follows:

- Total expenditures are divided into three categories: exploration and construction (with a local Rp share of 25%), routine O&M (with a local Rp share of 75%), and make-up well drilling during operation (with a local Rp share of 25%).
- The proportion of Rp costs spent in the local province is assumed at 75% for Java and Sumatra, 40% for eastern islands. The smaller share for the latter simply reflects the fact that small islands may not have any qualified local firms that can offer the required goods and services, and that these would be sourced from other parts of Indonesia.
- The total local expenditures are taken from a World Bank project as an example of a typical geothermal project.

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[28] R. Bacon and M. Kojima. 2001. *Issues in Estimating the Employment Generated by Energy Sector Activities.* World Bank, Sustainable Energy Department; M. Wei, S. Patadia, and D. Kammen. 2010. Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the US? *Energy Policy*. 38. pp. 919–931.

[29] For example, the study by Wei, Patadia, and Kammen (2010), calculates average job creation for coal of 0.11 job-year per GWh, but 0.25 job-years per GWh for geothermal.

Stakeholder Comment 4: Why Use Deterministic and Not Probabilistic Calculations?

Comment:

Setting the expected value of benefits as the ceiling at 50% probable value (P50) forces bidders (through competitive tendering) from the "expected value" and into a "failed project zone."[a] Ceiling tariffs should be set at P90. Using a probabilistic method, when the P50 value (for 2020, against large coal) is 14.53 US¢/kWh, the P90 value is 16.24 US¢/kWh.

Reply:

Our calculation for 2020 is 14.7 US¢/kWh, which is very close to a probabilistic calculation. However, if the recommendations we propose for improvements to the tendering process are implemented, it is doubtful that use of any ceiling, however derived, would result in more "failed" projects. For example, suppose qualified bidders assess the cost for some project at around 16 US¢/kWh, when the ceiling is 14.7 US¢/kWh. They will not bid 14.6 US¢/kWh, just below the ceiling, since a qualified bidder will know that at the lower price, the project cannot succeed. It may well be the case that a speculator or unqualified party bids 14.6 US¢/kWh (or just below)—and at this price the project is not viable, so the project fails. But if indeed 14.7 US¢/kWh is the government's best estimate of the benefits, then the appropriate mitigant is not to raise the ceiling to a P90 value of 16.24 US¢/kWh (as suggested)—at which point indeed a good developer would bid and develop a successful project—but to exclude the unqualified bidders by rigorous prequalification screening and a material bid bond. The point is not to set the tariff at a level to permit successful development by a qualified bidder, but to limit geothermal development to those projects for which costs are at or below the government's best estimate of the benefits.

Probabilistic (Monte Carlo) analysis is a useful technique to generate a range of answers based on statistical variations of the inputs. However, it does require a reasonable understanding of the likely variation of the input parameters, with the actual calculation then being undertaken a great many times (e.g., 1,000 independent calculations would be a minimum) to produce a statistically meaningful series of possible output results.

In the case of calculating the geothermal ceiling price, where this is based on the avoided cost of non-geothermal generation, the majority of the input parameters are not subject to variations that lend themselves to statistical descriptions. Some are based on actual values provided from *PT Perusahaan Listrik Negara* (e.g., fixed costs of thermal generation), some are simply fixed values selected to be representative of additional loadings that are being applied to the calculation (e.g., value of carbon) and some are forward projections taken from very limited published data (e.g., forward cost of coal). The actual value and the fixed value inputs are not subject to statistical variation. The forward projection numbers are subject to some statistical variation, but analyzing that variation is more easily undertaken by the simple sensitivity technique of running the calculation with a known variation on the selected input parameter (e.g., using alternative International Energy Agency forecasts for future energy prices, as in Table 4.1).

For the calculation of a ceiling price, a single value is required. It is not helpful to provide a range of possible values, and hence, particularly given the nature of the input variables, probabilistic analysis is not appropriate for this purpose. A simple sensitivity analysis will highlight where emphasis should be placed in the selection of the representative value of the relevant input variable (as we have done, for example, in the case of the valuation of greenhouse gas emissions in Table 4.5), but the end result still needs to be presented as a single tariff number representing the benefit of geothermal, above which the costs of geothermal outweigh the benefits. It may be noted that the most important assumption in the benefits calculation is the valuation of carbon, which is a decision that must be directly confronted by the government (see stakeholder comments on greenhouse gas valuation)—and which should not be buried among the many other variables in a probabilistic analysis.

[a] Comments provided by Chevron, 11 March 2014. Similar comments were received from Indonesia Geothermal Association.

- The tariff benefit is calculated such that the NPV of the induced benefits (row [10] of Table 4.9, $75.5 million) is the same as the NPV of the tariff recovery (row [13]). This calculated value is 1.8 US¢/kWh.

Table 4.9: Local Multiplier Impacts (for Java and Sumatra)

				NPV	2014	2015	2016	2017	2018	2019	2020	2025
1	**Rp portion**	Rp share										
2	Exploration, construction	0.25	$ million		14.0	24.0	18.5	21.6	6.3	0.0	0.0	
3	Routine O&M	0.75	$ million						8.0	8.4	8.8	11.3
4	Make-up wells	0.25	$ million						0.0	0.0	4.2	0.0
5	**Local province shares**											
6	Exploration, construction	0.75	$ million		10.5	18.0	13.9	16.2	4.8	0.0	0.0	0.0
7	Operation	0.75	$ million		0.0	0.0	0.0	0.0	6.0	6.3	6.6	8.4
8	Make-up wells	0.75	$ million		0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0
9	Total provincial expenditures		$ million		10.5	18.0	13.9	16.2	10.8	6.3	9.8	8.4
10	Multiplier	0.75	$ million	75.5	7.9	13.5	10.4	12.1	8.1	4.7	7.3	6.3
11	Energy sold		GWh							887.0	887.0	887.0
12	Tariff increment		US¢/kWh							1.80	1.80	1.80
13	Tariff recovery		$ million	75.5						16.0	16.0	16.0
14	Net cash flows		$ million	0.0	–7.9	–13.5	–10.4	–12.1	–8.1	11.3	8.7	9.6

GWh = gigawatt-hour, NPV = net present value, O&M = operation and maintenance, Rp = rupiah, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

The corresponding calculation for Indonesia's eastern islands results in a tariff benefit equivalent of 0.97 US¢/kWh. These values are included in the total tariff ceiling build-up (Table 4.10).

4.11 Proposed Tariff Ceilings

Table 4.10 shows the proposed tariff ceilings. These should be revised and published annually, and would apply to all tenders issued during the year in question.[30] MEMR would determine on a case-by-case basis which table applies (large grid, small island coal, small islands oil) to a particular tender, and the tender entity determines the target COD. For example, if this table were to apply to a tender, say, in November 2014, and the target COD were 2021, and the relevant region were "eastern island, oil;" then the tariff ceiling would be 28.8 US¢/kWh.

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30 In other words, if this table were published in mid-June 2014, then it would apply to all tenders issued between 1 July 2014 to 30 June 2015.

Table 4.10: Proposed Tariff Ceilings

			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	**Large grids**														
2	Avoided fixed cost	US¢/kWh	2.89	2.96	3.04	3.11	3.19	3.27	3.35	3.44	3.52	3.61	3.70	3.79	3.89
3	Avoided variable cost	US¢/kWh	3.85	4.00	4.16	4.33	4.50	4.68	4.87	5.06	5.23	5.41	5.59	5.77	5.97
4	GHG emission premium	US¢/kWh	2.70	2.76	2.83	2.90	2.98	3.05	3.13	3.20	3.28	3.37	3.45	3.54	3.63
5	Local environmental premium	US¢/kWh	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13	0.13
6	Energy security premium	US¢/kWh	0.68	0.71	0.74	0.77	0.80	0.83	0.87	0.90	0.93	0.96	0.99	1.02	1.06
7	Local eocnomic development	US¢/kWh	1.80	1.85	1.89	1.94	1.99	2.04	2.09	2.14	2.19	2.25	2.30	2.36	2.42
8	Total benefit, coal, large grids	US¢/kWh	**12.0**	**12.4**	**12.8**	**13.2**	**13.6**	**14.0**	**14.4**	**14.9**	**15.3**	**15.7**	**16.2**	**16.6**	**17.1**
9	**Isolated grids/Small islands**														
10	Avoided fixed cost	US¢/kWh	5.06	5.18	5.31	5.45	5.58	5.72	5.87	6.01	6.16	6.32	6.47	6.64	6.80
11	Avoided variable cost	US¢/kWh	6.66	6.74	7.02	7.32	7.63	7.95	8.29	8.64	8.95	9.27	9.61	9.96	10.32
12	GHG emission premium	US¢/kWh	4.06	4.16	4.26	4.37	4.48	4.59	4.70	4.82	4.94	5.07	5.19	5.32	5.45
13	Local environmental premium	US¢/kWh	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13	0.13
14	Energy security premium	US¢/kWh	0.68	0.71	0.74	0.77	0.80	0.83	0.87	0.90	0.93	0.96	0.99	1.02	1.06
15	Local economic development	US¢/kWh	0.97	0.99	1.02	1.04	1.07	1.10	1.12	1.15	1.18	1.21	1.24	1.27	1.30
16	Total benefit, isolated grids	US¢/kWh	**17.5**	**17.9**	**18.5**	**19.1**	**19.7**	**20.3**	**21.0**	**21.6**	**22.3**	**23.0**	**23.6**	**24.3**	**25.1**
17	**Eastern islands, oil**														
18	Avoided fixed cost	US¢/kWh	2.48	2.55	2.61	2.68	2.74	2.81	2.88	2.95	3.03	3.10	3.18	3.26	3.34
19	Avoided variable cost	US¢/kWh	19.02	19.05	19.28	19.52	19.75	19.99	20.23	20.48	20.71	20.95	21.19	21.43	21.67
20	GHG emission premium	US¢/kWh	2.35	2.41	2.47	2.53	2.60	2.66	2.73	2.80	2.87	2.94	3.01	3.09	3.17
21	Local environmental premium	US¢/kWh	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13	0.13
22	Energy security premium	US¢/kWh	0.68	0.71	0.74	0.77	0.80	0.83	0.87	0.90	0.93	0.96	0.99	1.02	1.06
23	Local economic development	US¢/kWh	0.97	0.99	1.02	1.04	1.07	1.10	1.12	1.15	1.18	1.21	1.24	1.27	1.30
24	Total benefit, Eastern Islands oil	US¢/kWh	25.6	25.8	26.2	26.6	27.1	27.5	27.9	28.4	28.8	29.3	29.7	30.2	30.7

US¢/kWh = cents per kilowat-hour.

Source: Authors' calculations.

Adjusting Tariff Ceilings for Government-Funded Exploration Costs

In the event that government has paid for exploration drilling as a public good (for example under the auspices of the Geothermal Fund) prior to tender, then the tariff ceiling shall be adjusted downward by an amount that makes the NPV of the exploration expenditures equal to the NPV of the tariff ceiling adjustment, where NPVs are calculated at the government's opportunity cost of capital.

If applicable, the ceiling tariffs shall be adjusted downward by the amount Ω, in $¢/kWh, such that the following equation is satisfied:

NPV(E) = NPV(R, Ω)

where:

NPV(E) = NPV of the stream of annual expenditures on pre-tender exploration drilling, evaluated at the discount rate corresponding to the government's opportunity cost of capital

NPV(R, Ω) = NPV of the tariff recovery payments, evaluated at the discount rate corresponding to the government's opportunity cost of capital

NPV(R, Ω) is to be calculated as:

$$NPV(R,\Omega) = \sum_i \frac{\Omega g_i}{(1+r)^i}$$

where

g_i = Average annual electricity sold in year i, in kWh per year

R = Discount rate corresponding to the government's opportunity cost of capital

The calculation is illustrated in Table 4.11. It is assumed that up-front exploration expenditures are $5 million in Year 1, $15 million in Year 2, and $10 million in Year 3. At the opportunity cost of capital of 7%, the NPV is $25.9 million. For a 110 MW project at 0.9 load factor, the cost is recovered across 867 GWh/year. A value of 0.64 US¢/kWh makes the NPV of the cost recovery stream exactly equal to the NPV of exploration. The tariff ceiling would therefore be adjusted downward by 0.64 US¢/kWh.

Table 4.11: Sample Calculation, Tariff Ceiling Adjustment

	NPV	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Exploration expenditures ($ million)	25.9	5	15	10	0	0	0											
Annual generation (GWh)								867	867	867	867	867	867	867	867	867	867	
Tariff adjustment (US¢/kWh)								0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	
Recovery of costs ($ million)	25.9	0.0	0.0	0.0	0.0	0.0	0.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	

GWh = gigawatt-hour, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

However, if the government recovers the up-front de-risking from the developer at the time of financial closure (see Section 8), then no adjustment to the ceiling is required.

5 Power Purchase Agreements

The prospective PPA should be provided at the time of tender. All relevant terms and conditions, and in particular the schedules relating to the tariff, should be fixed in advance. The present system of ad hoc, post tender negotiation of tariff escalation terms should be dropped: a single tariff escalation formula should be adopted as part of the tender, and should be binding on both parties. However, there is a strong case to renegotiate the tendered price when there are delays outside the developers' control, and when the resource as revealed by delineation drilling proves to be significantly lower than that expected at tender.

5.1 Escalation and Indexation

Current Practice

The most recent formulae for tariff escalation, as negotiated between PLN and developers, take the form[31]

$$P(t) = [(1 - \alpha)P(0)] + [\alpha P(0)USPPI(t)/USPPI(0)]$$

where

$P(t)$	=	tariff in year t, in US¢/kWh
$P(0)$	=	(base) tariff at COD = Tariff bid at time of tender, in year (0)
$USPPI(t)$	=	United States Producer Price Index for year (t)
$USPPI(0)$	=	United States Producer Price Index for year (0)
α	=	coefficient

α is a coefficient that has been set by ad hoc negotiation and appears to be in the range of 0.25 to 0.4. As a matter of logic, α should be the proportion of the cost structure attributable to post-commissioning O&M (including the cost of make-up wells), but it is unclear that this rationale is indeed the basis for its negotiated value in the past.

However, provided the value is set at the time of tender, and not subject to post-tender negotiation, one might argue that the value of α (or its precise rationale) does not really matter, for it can then be factored into the cash flow forecast used by the developer to derive the bid price. All other things equal, to produce the same equity return, a lower value of α will result in a higher bid for the base price, and would therefore matter only for bids close to the tariff ceiling. Therefore, we are of the view that a rational evaluation of α is in fact desirable.

31 Template of Geothermal PPA, published on the PLN's website.

International Practice

International practice reveals much variation, including:

- Tariffs fixed at the time of PPA signature, with no escalation (an option offered in the Sri Lanka FITs);
- Tariffs fixed, and declining over time (as in the case of the Malaysian FIT) called tariff "degression" in the German Model—the idea being to offer relatively generous tariffs initially, and then reduced over time so as to "incentivize early introduction";[32]
- Tariff escalation formulae of the same type as Indonesia, but where α is based on the regulator's estimate of O&M costs for the technology in question, and escalated on an index of domestic inflation (Sri Lanka FIT);
- Tiered tariffs for recovery of investment costs, with a higher tariff in the first few years, and a much lower tariff in subsequent years (Sri Lanka FIT).[33] This is important where renewable energy projects are mainly small (in Sri Lanka the fixed FITs apply only to projects less than 10 MW), and financed locally through the commercial banking system, so interest rates are high and tenors are 5–7 years. Under these circumstances, a fixed constant tariff for investment cost recovery would result in unacceptable debt service cover ratios (DSCR);[34] and
- Front-loaded geothermal tariffs, with which Indonesia does have some experience. (For example, in 1993 Unocal signed an agreement with PLN for Sarulla, albeit later cancelled by mutual agreement, which stipulated a price of 7.6 US¢/kWh for the first 14 years, 5.75 US¢/kWh for years 15 to 22, and 5.21 US¢/kWh until year 30.[35] At that time the cost of coal-fired generation was around 4.0 US¢/kWh.)

Such options apply only to production-cost based FITs or to purely negotiated tariffs. For avoided cost tariffs, most are contemporaneous tariffs, under which the applicable tariff is not fixed at time of PPA signature, but is published each year by the regulator (avoided cost tariff in Sri Lanka from 1996–2009, Viet Nam). Sri Lanka has a tariff collar where the amount payable cannot be less that 90% of the published tariff in the year of PPA signature. In Viet Nam, there is both collar and cap whereby a developer who opts for the 90% protection of his downside gives up the potential of the corresponding upside, under which option a developer cannot receive more than 110% of the tariff at PPA signature.

Methodology for Estimating the Escalable Fraction

Using a financial model for a World Bank geothermal project, one can disaggregate the developer's total cash flow streams in the bid tariff determination by those components that are fixed at time of financial closure (equity, debt service payments),[36] and those that occur after COD (make-up wells, routine O&M)—costs which one would expect to escalate in nominal terms. Table 5.1 shows the NPVs for these cost streams using the project's 11.8% calculated equity returns as the discount rate.[37] The share of costs after COD is 37.6%.

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32 This proposition is widely asserted by the advocates of FITs—while nominally plausible, reliable evidence that degression actually incentivizes early adoption is scant.

33 A tiered tariff was also proposed by the winning bidder for the Malitbog plant, part of the big Leyte geothermal project in the Philippines.

34 See further discussion of DSCR in Appendix 4.

35 GeothermEx, Inc. 2010. *Assessment of Geothermal Resource Risks in Indonesia*. Washington, DC: Public–Private Infrastructure Advisory Faculty and the World Bank.

36 Of course, while principal repayments are fixed at time of financial closure, depending on the type of financing involved interest rates may be variable unless hedged with an interest rate swap.

37 Note that income tax is excluded from the calculation.

Table 5.1: Classification of Costs

		NPV	1	2	3	4	5	6	7	8	9	10
1	Discount rate for NPV	0.118										
2	Equity ($ million)	127.0	55.3	93.0	4.3	0.0	0.0					
3	Debt service ($ million)	55.4	0.0	0.0	0.0	0.0	5.0	5.4	10.5	14.6	14.4	14.1
4	Total construction related ($ million)	182.3	55.3	93.0	4.3	0.0	5.0	5.4	10.5	14.6	14.4	14.1
5	O&M, make-up wells ($ million)	110.1	0.0	0.0	0.0	0.0	10.4	10.8	26.2	11.8	28.2	12.9
6	Total ($ million)	292.4	55.3	93.0	4.3	0.0	15.4	16.2	36.7	26.5	42.6	27.0
7	O&M share, as NPV	0.376										

NPV = net present value, O&M = operation and maintenance.

Source: Authors' calculations.

However, the so-calculated O&M share is a function of the discount rate: at the project's overall weighted average cost of capital (WACC) of 8% the fraction is 0.45; at the developer equity return target of 14% the fraction is 0.34 (Table 5.2). Thus even the lowest share of 34% is considerably above the 25% escalable share encountered in some PPAs.

Table 5.2: Operation and Maintenance Shares as Function of Discount Rate

Discount rate	O&M share	
8.0%	0.45	WACC
10.0%	0.41	
11.8%	0.38	Post tax nominal IRR
12.0%	0.37	
14.0%	0.34	Developer equity target

IRR = internal rate of return, O&M = operation and maintenance, WACC = weighted average cost of capital.

Source: Authors' calculations.

Conclusions on Escalation

Provided the escalation formula is known at the time of tender, and applied to all projects rather than set by ad hoc negotiation, we see no compelling reason why current indexation practice should be changed, but based on such estimates as are available, for the time being, we recommend a value for α of 0.375.

5.2 Renegotiation of Power Purchase Agreements

The current reality is that many projects are stalled or delayed for a variety of reasons. MEMR cannot meet its geothermal targets, and therefore a renegotiation of a significant number of projects is inevitable. That being said, it is better that renegotiation be subject to a formal policy applicable to all, rather than through ad hoc negotiations, which have high transaction costs and may well add yet further delays.

Of course it is true that where a signed PPA exists, it is for the parties concerned (PLN and the developers) to negotiate. Nevertheless, that does not preclude MEMR from issuing guidelines that stipulate the principles that should be applied to both when a renegotiation is warranted, and what is subject to negotiation. This is particularly true given that PLN is in principle ill-disposed to renegotiating tariffs. It argues that the regulations (and the law) stipulate that the tariff shall be determined by tender, and that if the bid price cannot be achieved, then the correct remedy is to return the WKP to the government to be re-tendered.

MEMR may be reluctant to issue an explicit policy on renegotiation for fear that it would open a floodgate of requests to take advantage of any tariff increase. There is also the potential danger that unsuccessful bidders may protest if the revised base price is higher than their earlier rejected tender offers. But with so many projects stalled, PPA renegotiations cannot be avoided, and if that process lacks transparency, it would be even more likely to lead to protests.

The biggest potential issue is that all the unserious developers will seek to renegotiate. The difficulty is that one cannot use exploration (or delineation) drilling expenditure as the yardstick for seriousness if drilling cannot even begin for lack of the necessary permits, which is a common cause of delay.

However, serious developers can easily be defined as those who:

- post the $10 million performance bond at the time of the original tender bid;
- in the absence of a bond, show evidence of logistical and drilling expenditures of at least $10 million; and/or
- in the absence of past exploration expenditure of at least $10 million, are willing to post such a bond as condition precedent for a revised PPA (and would be obliged to show evidence of funds before a renegotiation procedure is commenced, to avoid wasting PLN's time).[38]

A tariff should be renegotiated after tender under the following circumstances:

- Delineation drilling shows that the resource as credibly defined using a recognized international standard is significantly different from the reference power capacity stipulated at time of tender (significant is defined as +25%).
- Financial closure cannot be reached within the time frame estimated by the developer at the time of tender for reasons outside the control of the developer.

Projects that have reached financial closure should not be open to renegotiation.

Any renegotiated tariff shall be subject to the additional ceiling that the increase may not be greater than 50%, and that any renegotiated base price is below the applicable tariff ceiling (for the revised COD at which the renegotiated tariff applies).

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[38] Such as a standby letter of credit, that can be drawn immediately upon signature of the revised PPA, or cancelled if the parties cannot reach agreement (in which case the business licence would in any event be withdrawn, and the project retendered).

5.3 Adjustment for Project Size

In the case of a significantly different resource size, the adjusted tariff shall be subject to change according to a formula of the type:

$$P(MW_a) = P(MW_x)\left(\frac{MW_a}{MW_x}\right)^{-\gamma}$$

where

MW_x	=	tender reference project size
$P(MW_x)$	=	bid tariff for project of the tender reference MW size, in US¢/kWh
$P(MW_a)$	=	tariff for project of the final size
MW_a	=	final project size
g	=	coefficient, typically in the range of 0.15–0.3

MEMR could calculate the applicable value of the coefficient γ based on its geothermal production cost model, which coefficient should be stipulated at the time of any tender.

Alternatively, to avoid the need for statistical estimation of the above production function, one may directly use the MEMR production cost model, and use the (linearly) interpolated values as shown in Section 2, Figure 2.3.

It could be argued that a developer would be discouraged from developing a slightly larger project in the knowledge that the tariff would decrease. However, the relevant criterion is not MW for the sake of MW, but rather developing the geothermal resource with an equitable distribution of the benefits of the country's resource endowment.

Sample Calculation: Variation in Project Size

Suppose the following at time of tender:

- Estimated size of project: 55 MW
- Base price established at tender: 9.5 US¢/kWh
- Estimated COD: 2015
- Ceiling price (Section 4, Table 4.10) of 12.8 US¢/kWh (large grids)

Subsequent delineation drilling shows the commercially viable size to be 40 MW. What should be the revised tariff?

According to the MEMR production cost model, a 55 MW project has a typical tariff of 10.5 US¢/kWh (Section 2, Figure 2.3). The interpolated value for a 40 MW project is 11.64 US¢/kWh, an increase of 10.9% over the tariff for the original 55 MW project cost.

This percentage increase is then applied to the original bid price of 9.5 US¢/kWh, so the adjusted tariff would be 9.5 x (1.109) = 11.65 US¢/kWh.

The increase is less than 50%, and the new tariff is lower than the 12.8 US¢/kWh tariff ceiling applicable to a 2015 COD.

5.4 Adjustment for Delay

In the case of delay caused by permitting or other problems outside the control of the developer, the allowable tariff escalation should be defined by the following procedure:

- Let the original tender price be **P***.
- Calculate the tariff for the project in question using the MEMR production cost model, using today's most likely overnight costs for drilling, steam above ground system (SAGS) and power plant construction, say **P(o)**.
- If the agreed delay attributable to parties other than the developer is ***N*** years, recalculate the tariff, using the same model, and the same set of *technical* assumptions (number of wells and their success rate, etc.), but with cost assumptions corresponding to best estimates ***N*** years ago. This recalculated base price is ***P(N)***.
- The allowable rate of increase is ***P(o)/P(N)***, which is then applied to the original tender price ***P****.

This procedure requires estimates of what prices were ***N*** years ago. The historical record shows that the costs of different major components escalate at different rates: the cost of drilling in particular has risen much faster than that of power plant construction, and faster than the general rate of inflation.

Geothermal energy project costs would be classified according to the categories shown in Table 5.3, each deflated using its own index.

Table 5.3: Escalation of Cost Categories

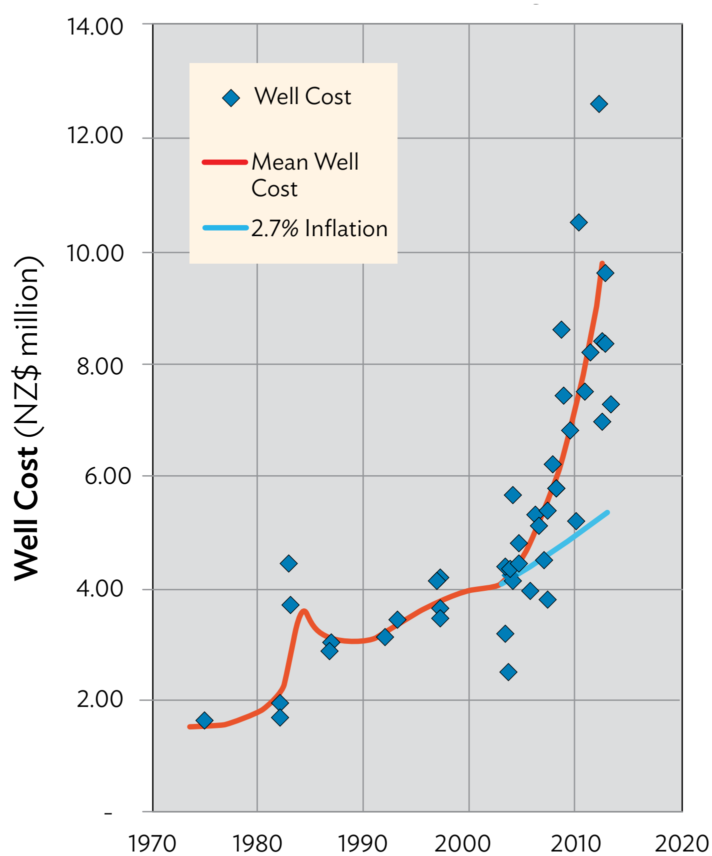
		Source
Drilling	Average drilling costs	Average of indexes noted in Table 5.4
SAGS	Steel price index (hot-rolled coil)	www.steelprices.com
Power plant	MUV index	World Bank. www.worldbank.org (updated 3–4 times/year)
US costs not included above (contingencies, management)	US GDP deflator	Government of the United States, US Department of Commerce, Bureau of Economic Analysis. http://www.bea.gov/iTable/iTable.cfm?ReqID=9&step=1#reqid=9&step=1&isuri=1 (updated 3–4 times/year)
Indonesian costs not included above (land, permits, etc.)	Indonesian GDP deflator	World Bank. www.worldbank.org; International Monetary Fund. www.imf.org

GDP = gross domestic product, MUV = manufacture unit value, SAGS = steam above ground system, US = United States.
Source: Authors' calculations.

Drilling

Over the last decade, geothermal drilling costs have increased at unprecedented rates, which cannot be explained merely by any increase in depths or general inflation. Rather, the driving force has been the demand for drilling in the oil and gas sector, which has been reactivated by the increase in global oil prices and (in the US) by drilling for shale oil and gas (fracking). Figure 5.1 shows geothermal drilling costs in New Zealand.

Figure 5.1: Geothermal Well Drilling Costs



NZ$ million = million New Zealand dollars.
Note: NZ$10 million = $8.2 million.
Source: H. Hole. 2013. *Geothermal Drilling—Keep it Simple.* Proceedings of the New Zealand Geothermal Workshop. Rotorua.

There are no published indexes for drilling geothermal wells, but a number of cost indices are available for the oil and gas industry, dominated by US costs. These include:

- Spears Drilling and Completion Services Index (proprietary);
- IHS[39] Drilling Index (proprietary); and
- US Bureau of Labor Statistics.[40]

Oil and gas drilling costs are strongly correlated with oil prices and numbers of drilling rigs in operation. Well prices increased sharply in the global boom of 2006–2008, and then declined as the commodities bubble and financial markets collapsed in 2008/2009. What matters is not the absolute value of costs or their index values, but the relative changes over time, because under the proposed procedure the level of prices is benchmarked against the current estimate in the MEMR production cost model. Table 5.4 shows a comparison of these various indexes, and the deflators that result.

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[39] The company IHS was previously known as Information Handling Services, Inc.

[40] The material can be accessed on the US Bureau of Labor Statistics website. The Industry/Product code is: PCU21311121311101. See US Bureau of Labor Statistics. Producer Price Index (PPI) - Drilling Oil and Gas Wells Industry - Drilling Oil, Gas, Dry, or Service Wells. https://www.quandl.com/BLS/PCU21311121311101-Producer-Price-Index-PPI-Drilling-oil-and-gas-wells-Industry-Drilling-oil-gas-dry-or-service-wells

Table 5.4: Drilling Index Deflators (Relative to Current 2014 Prices)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014 (est)
IHS[a]	100	106	122	127	136	160	138	152	169	171	169	173.2
Change		6.0%	15.1%	4.1%	7.1%	17.6%	–13.8%	10.1%	11.2%	1.2%	–1.2%	2.5%
Deflators	**0.58**	**0.61**	**0.70**	**0.73**	**0.79**	**0.92**	**0.80**	**0.88**	**0.98**	**0.99**	**0.98**	**1.00**
New Zealand Geothermal[b]	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.3	10.0	10.3	10.6
Change		12.5%	11.1%	10.0%	9.1%	8.3%	7.7%	7.1%	10.7%	20.5%	3.0%	2.5%
Deflators	**0.38**	**0.43**	**0.47**	**0.52**	**0.57**	**0.62**	**0.66**	**0.71**	**0.79**	**0.95**	**0.98**	**1.00**
US BLS PPI[c]									353	383	429	440
Change										8.5%	12.0%	2.5%
Deflators									**0.80**	**0.87**	**0.98**	**1.00**
Spears[d]						1.16	0.8	0.87	1.08	1.1	1.08	1.025
Change							–31.0%	8.7%	24.1%	1.9%	–1.8%	–5.1%
Deflators						**1.13**	**0.78**	**0.85**	**1.05**	**1.07**	**1.05**	**1.00**

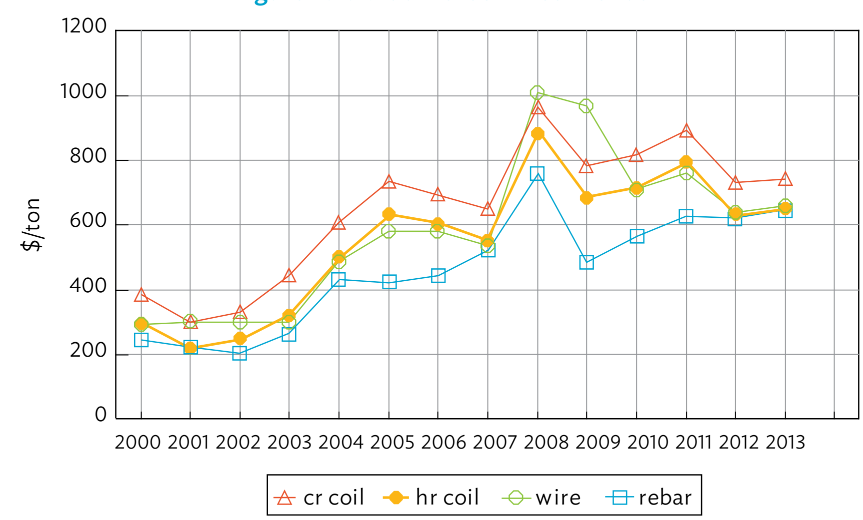
IHS = company formerly known as Information Handling Services, Inc.; US BLS PPI = United States Bureau of Labor Statistics producer price index.

Sources:
[a] IHS. www.ihs.com
[b] See Figure 5.1.
[c] Government of the United States, Department of Labor. Bureau of Labor Statistics website. www.bis.gov
[d] Spears and Associates, Inc. January 2014. Drilling and Completion Services Cost Index. 4th Quarter 2013. Tulsa, OK.

Steam Above Ground System

We propose to index SAGS costs with international steel prices (Figure 5.2). Since steel pipe is generally made from hot rolled coil, this is an appropriate index to use for this purpose.

Figure 5.2: Global Steel Price Trends



cr = cold rolled, hr = hot rolled.
Source: Steelprices.com. www.steelprices.com

Power Plant Costs

Power plant costs are proposed to be indexed by the MUV Index, published by the World Bank (which also provides values for the US GDP deflator). This is a measure of the price of developing country imports of manufactured goods in US dollar terms, and can be downloaded from the World Bank website (Table 5.5).[41]

Table 5.5: Manufacture Unit Value Index

Manufactures Unit Value (MUV) Index
Release date: Jan 6, 2014
expressed in U.S. dollar terms
History 1960-2012; projections 2013-2025
email: gcm@worldbank.org

	MUV Index		U.S. GDP deflator	
	Index 2010 = 100	ch%	Index 2010 = 100	ch%
1990	83.32	3.8	66.05	3.7
1991	82.49	-1	68.24	3.3
1992	83.89	1.7	69.8	2.3
1993	86.62	3.3	71.46	2.4
1994	83.83	-3.2	72.98	2.1
1995	91.84	9.6	74.5	2.1
1996	90.15	-1.8	75.86	1.8
1997	85.91	-4.7	77.16	1.7
1998	82.17	-4.4	78	1.1
1999	80.6	-1.9	79.11	1.4
2000	79.56	-1.3	80.91	2.3
2001	76.58	-3.8	82.76	2.3
2002	75.68	-1.2	84.04	1.5
2003	79.62	5.2	85.72	2
2004	85.03	6.8	88.07	2.7
2005	87.71	3.2	90.89	3.2
2006	89.93	2.5	93.68	3.1
2007	95.44	6.1	96.17	2.7
2008	102.84	7.8	98.05	2
2009	96.46	-6.2	98.81	0.8
2010	100	3.7	100	1.2
2011	108.89	8.9	101.96	2
2012	107.53	-1.2	103.75	1.8
2013	106.06	-1.4	105.93	2.1
2014	107.73	1.6	108.31	2.2
2015	108.96	1.1	110.98	2.5
2016	110.47	1.4	113.22	2
2017	112.01	1.4	115.51	2
2018	113.65	1.5	117.85	2
2019	115.38	1.5	120.23	2
2020	117.21	1.6	122.65	2
2021	119.1	1.6	125.13	2
2022	121.05	1.6	127.66	2
2023	123.05	1.7	130.24	2
2024	125.09	1.7	132.87	2
2025	127.17	1.7	135.55	2

ch% = percentage change, GDP = gross domestic product, U.S. = United States.
Source: World Bank. Manufactures Unit Value Index. www.worldbank.org. Accessed 6 January 2014.

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41 MUV is a composite index of prices for manufactured exports from the fifteen major developed and emerging economies to low- and middle-income economies, valued in US dollars. For the MUV (15) index, unit value indexes in local currency for each country are converted to US dollars using market exchange rates and are combined using weights determined by the share of each country's exports in Group of 15 (G-15) exports to low- and middle-income countries.

The resulting index values are shown in Table 5.6. Rows [1] to [6] show the actual index values, and rows [7] to [12] show the deflators—i.e., the past values of the index when the 2014 value is set at 1. For example, if a project were delayed by 5 years, then the index values of 2009 would apply (as highlighted in the table)—so for example, drilling costs would be taken at 0.67 of the 2014 cost estimate; power plant costs at 0.93 of the 2014 cost estimate, and so on.

Table 5.6: Manufacture Unit Value Index (Index Values)

			2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
			9	8	7	6	5	4	3	2	1	0
1	**Index Values**											
2	Land and Permits	Indo GDP defl.	0.76	0.78	0.81	0.83	0.86	0.89	0.91	0.94	0.97	1.00
3	Drilling	Average costs	5.0	5.5	6.0	6.5	7.0	7.5	8.3	10.0	10.3	10.5
4	SAGS	Steel prices	52.5	53.4	56.0	59.6	56.7	58.3	61.4	60.4	60.7	62.3
5	Power Plant	MUV	100.0	101.2	106.0	112.8	106.4	109.1	114.5	110.8	111.1	114.0
6	Other	US GDP deflator	100.0	103.3	106.3	108.6	109.6	110.7	112.3	114.8	117.4	119.8
7	**Deflators**											
8	Land and Permits		0.76	0.78	0.81	0.83	0.86	0.89	0.91	0.94	0.97	1.00
9	Drilling		0.48	0.52	0.57	0.62	0.67	0.71	0.79	0.95	0.98	1.00
10	SAGS		0.84	0.86	0.90	0.96	0.91	0.94	0.99	0.97	0.98	1.00
11	Power Plant		0.88	0.89	0.93	0.99	0.93	0.96	1.00	0.97	0.97	1.00
12	Other		0.83	0.86	0.89	0.91	0.91	0.92	0.94	0.96	0.98	1.00

Indo GDP defl. = Indonesia gross domestic product deflation, MUV = manufacture unit value, SAGS = steam above ground system, US GDP = United States gross domestic product.

Source: World Bank. Manufactures Unit Value Index. www.worldbank.org. Accessed 6 January 2014.

The illustrative calculations presented here use the data from a World Bank geothermal project and a (simplified) financial model.

Rows 2–6 of Table 5.7 contain the investment costs over a 5-year period. The total is $359.1 million, assuming that these are the 2014 costs. Assume further that the original bid (or negotiated) price using these costs was 8.5 US¢/ kWh, and that the applicable tariff ceiling at the time of the bid was 10.4 US¢/kWh. Using a production-cost-based financial model and 2014 costs (i.e., the costs shown in rows 2–7), the estimated tariff calculates to 9.47 US¢/kWh.

Table 5.8 shows the calculation for a range of delays, all calculated with the same production cost model. For no delay, the cost is $359 million. For a 1-year delay, using the deflators for a 1-year delay as shown in Table 5.6, the cost is only $351 million and tariff calculates to 9.29 US¢/kWh. The difference in tariff is 0.17 US¢/kWh, or 1.87% of the 2013 price. Therefore, this increase is allowed on the original bid price, and the new base price for the revised PPA would be 8.5 US¢/kWh X 1.0187 = 8.66 US¢/kWh.

Table 5.7: Adjusted Costs, $ million

		$ million			1	2	3	4	5
1	**Current Estimates**	Total Cost							
2	Land and Permits	1.0			0.475	0.475			
3	Drilling	139.2			69.6	55.7	13.9	0.0	0.0
4	SAGS	31.8			0.0	6.8	8.7	11.6	4.7
5	Power Plant	152.4			0.0	36.7	43.4	57.9	14.5
6	Other	35.7			8.0	10.9	7.0	7.4	2.4
7	Total Initial Investment	359.1			77.6	110.1	73.1	76.8	21.6
8	Make-up Wells				18.0				
9	**Adjusted**								
10	Delay, years	5		Deflator					
11	Land and Permits	0.8	0.1	0.86	0.4	0.4	0.0	0.0	0.0
12	Drilling	92.8	46.4	0.67	46.4	37.1	9.3	0.0	0.0
13	SAGS	29.0	2.8	0.91	0.0	6.2	7.9	10.5	4.3
14	Power Plant	142.3	10.1	0.93	0.0	34.2	40.5	54.0	13.5
15	Other	32.6	3.0	0.91	7.3	10.0	6.4	6.8	2.2
16	Total Initial Investment	296.7	62.4		53.7	87.5	64.2	71.3	20.0
17	Make-up Wells			0.66	12				

SAGS = steam above ground system.
Source: Authors' calculations.

Table 5.8: Allowable Tariff Increase

	Delay	Increase	Tariff	Change in Tariff	Change	Total Cost
	Years	$ million	US¢/kWh			$ million
2014	0	0	9.47			359
2013	1	8.0	9.29	0.17	1.87%	351
2012	2	13.4	9.15	0.31	3.31%	346
2011	3	31.2	8.60	0.87	9.15%	328
2010	4	51.1	8.12	1.34	14.21%	308
2009	5	62.4	7.84	1.63	17.19%	297
2008	6	59.3	7.81	1.66	17.55%	300
2007	7	77.6	7.41	2.06	21.73%	282
2006	8	92.8	7.06	2.41	25.43%	266

US¢/kWh = cents per kilowatt-hour, US = United States.
Source: Authors' calculations.

Similarly, for a 5-year delay, the allowable tariff increase would be 1.63 US¢/kWh, or 17.19% of the price had it been calculated 5 years ago. The new base price would therefore be 8.5 US¢/kWh X 1.1719 = 10.26 US¢/kWh. The increase is below the threshold of 50%, and the new tariff is below the applicable tariff ceiling of 10.4 US¢/kWh. Note that the developer does not need to reveal his estimates of capital costs: the increase is applied to his original tender price.

Are there perverse (and unintended) incentives in such a procedure? Obviously, the longer the delay, the greater is the tariff increase that is allowable, so it might appear that a developer has an incentive to delay, and particularly so in the case of a unserious developer who has neither posted a bond, nor incurred any exploration expenses. Since the delay interval is fixed only once, the reason for the force majeure has been cured, it may be thought that there is a disincentive to cure—at least as long as it takes for the renegotiated price to reach the tariff ceiling.

However, we offer the following rejoinders to such concerns:

- Under our recommendations, developers have to post a $10 million bond as a precondition for any PPA renegotiation. This they recover only once expenditures for exploration or delineation drilling are actually incurred: that sum should be sufficient to discourage speculators.
- The delay interval is only that which can be shown to be outside the control of the developer, as certified by an independent expert engaged by the tender entity[42]—a precondition of which is that the force majeure is cured so that project development can resume.[43] A developer cannot know for sure what the independent determination of the delay will be. Moreover, since declaration of force majeure requires a declaration of what best efforts to cure are being proposed, this provides additional evidence to the evaluator to judge whether or not good faith efforts to cure can be shown: and if a developer has not acted according to this plan, or the plan to cure is unreasonably protracted, then the share of delay that is attributable to government can be adjusted downward.
- PPA renegotiations can drag on for years, which cannot be in the interest of government or developers. The proposed procedure reduces the negotiation to confirmation of the period and cause of delay, after which the actual tariff adjustment is then mechanistic and not subject to protracted debate.

Adjustment of Power Purchase Agreements for Proposed Pertamina Geothermal Energy Partnerships

PGE is presently negotiating commercial partnerships for some of its old projects, but these are unlikely to be viable at the old, previously agreed tariffs.

We recommend that the tariffs in these cases be recalculated in two stages. In stage one, the originally agreed price would first be adjusted for the new WACC, which may be significantly different to the original estimate with the entry of private partners who would contribute significant equity up front. The adjustment factor is simply the new WACC (with the commercial partner) divided by the original WACC at the time the first tariff was negotiated. The WACC-adjusted base tariff therefore follows as:

$$\text{WACC-adjusted base tariff} = BT^*(1-\alpha)^*WACCAF+\alpha\, BT$$

where

α	=	proportion of the net present value of all project costs attributable to O&M and make-up well expenses (see Section 5.1).
BT	=	original agreed tariff, in US¢/kWh.

In the second stage of the adjustment, the WACC-adjusted base tariff would be adjusted for delay, using the same methodology as the competitively tendered projects (see above), and subject to the same tariff ceiling.

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42 The independence of the expert so engaged by the tender entity is an issue, and may need to be an individual international expert, rather than local Indonesia expert.

43 In this context, force majeure means any government force majeure, whether formally enumerated in the PPA or not, that is outside the control of PLN (as the counterparty in the PPA). For example, PLN has no control over the timely issuance of environmental and forestry permits, and unreasonable delays in such issuance, not attributable to the developer, would be grounds for an adjustment in price under this provision.

5.5 Procedure

We recommend that in the future, tenders should be conducted by a new central entity on behalf of central and provincial governments.

The recommended procedure in the case of delay is as follows:

- The developer notifies the buyer, and the independent tender entity, of force majeure as required by the PPA, and that therefore he cannot meet the agreed COD. This requires the developer to declare what efforts he is taking to cure the problem.
- The delay in question must be at least 1 year.
- The new tender entity[44] appoints an independent technical expert to assess the validity of a claim that the delay has occurred for reasons outside the control of the developer, and to recommend the number of years that can reasonably be attributed to government.
- The final value of the period of delay may only be known once the condition of force majeure is cured.
- Once the period of delay is agreed, and the project moves forward again, the tender entity calculates the recommended value of the revised base price, using its production cost model, as described above, but in any event no greater than the applicable tariff ceiling, and no greater than 50% of the original tender price. If either of these two ceilings are exceeded, the project would need re-tendering unless the developer accepted the ceiling price.

It is recognized that the establishment of this new tender entity may take some time, during which time MEMR should assume the duties as described in the previous paragraphs, in collaboration with local governments (who own the site) and MoF.

[44] See Section 7 on the proposal to create a new central tender entity.

6 Recovery of Incremental Costs

In Indonesia, the mechanism for recovering the incremental cost of geothermal energy is the existing subsidy mechanism from MoF to PLN—in effect, the incremental costs are borne by government, not by consumers. At some point it may be that the subsidy is eliminated and the consumer tariff becomes fully cost-reflective, but that is unlikely in the short term. Consequently the focus here is on the magnitude of additional subsidy that will be required from MoF if the pace of geothermal energy development accelerates, as called for by the FTP2 program.

6.1 Cost of Existing Projects

There is general agreement that many of the low cost geothermal fields have already been developed: many of these now operating projects have costs below that of coal. Tariffs at the existing projects are shown in Table 6.1.

Table 6.1: Tariffs at Existing Geothermal Projects

	COD	MW	US¢/kWh
Muara Laboh	2017/2018	220	9.40 (PPA)
Sarulla 1	2017/2018	330	6.79 (PPA)
Rajabasa	2020/2021	220	9.50 (PPA)
Rantau Dedap	2019	220	8.86 (PPA)
Blawan Ijen	2019	110	8.58 (PPA)
Atadei	2016	5	9.50 (PPA)
Ungaran	2019	55	8.09 (PPA)
Sorik Marapi	2019/2020	240	8.10 (tender price)
Suoh Sekincau	2020/2021	220	6.90 (tender price)
Cisolok Cisukarame	2019	50	Rp630 (tender price)
Jaboi	2019	10	Rp1,705 (tender price)
Tangkuban Perahu	2019	110	Rp533.6 (tender price)
Jailolo	2017	10	Rp1,727 (tender price)
Sokoria	2017/2019	5	Rp1,250 (Tender price)
Rawa Dano	2019	110	8.39 (tender price)
Tampomas	2019	45	6.50 (tender price)
Batu Raden	2018/2019	110	9.47 (tender price)
Ngebel/Wilis	2019/2020	165	7.55 (tender price)
Ciremai	2019	110	9.70 (tender price)
Guci	2019	55	9.09 (tender price)
Hu'u Daha	2021	20	9.65 (tender price)
Seulawah Agam	2018	110	6.90 (tender price)

COD = commercial operating date, MW = megawatt, PPA = power purchase agreement, Rp = rupiah, US¢/kWh = cents per kilowatt-hour.

Sources: Government of Indonesia, Ministry of Energy and Mineral Resources. Jakarta; various published information.

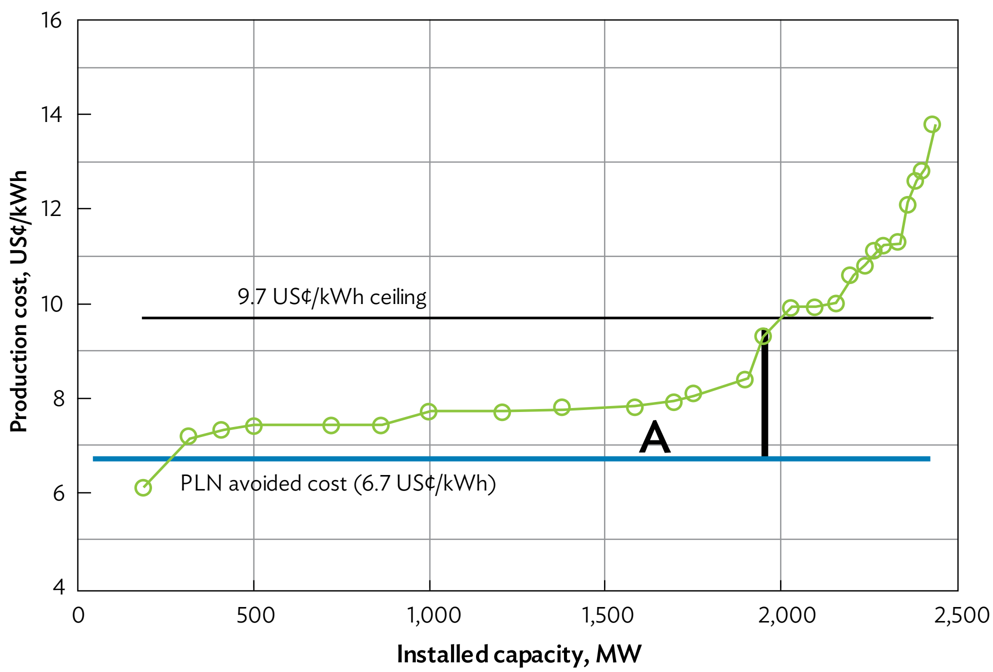
With the change in coal pricing to international levels, in 2013 PLN's coal generation costs were around 6.7 US¢/kWh (significantly above earlier costs when coal price to PLN was at a low administered price). The generation-weighted average cost is 6.3 US¢/kWh.

6.2 Incremental Costs of Future Projects

Methodology

To calculate the subsidy requires estimates of the costs of future projects. This can be displayed in the form of a supply curve, which plots cumulative capacity as a function of cost. Figure 6.1 shows such a supply curve for the geothermal projects in Java and Sumatra, as calculated in 2010 by the Castlerock report. This showed a total capacity of geothermal projects in the two main islands of 2,432 MW. Also shown in this figure are the estimated PLN avoided costs (2013) and the former 9.7 US¢/kWh ceiling price.

Figure 6.1: Castlerock Supply Curve, Java and Sumatra

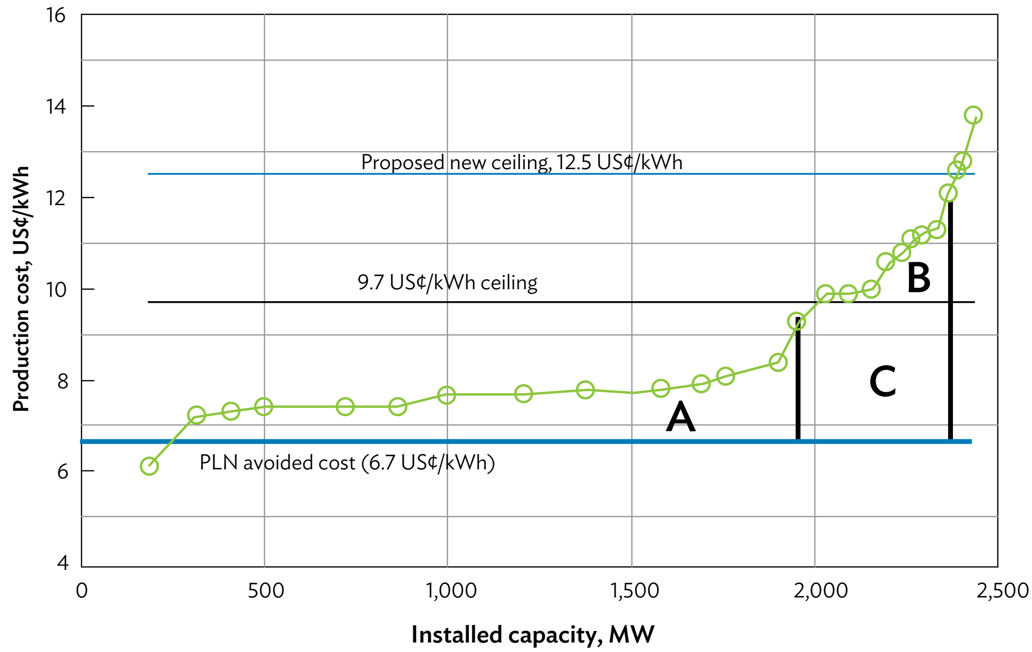


MW = megawatt, US¢/kWh = cents per kilowatt-hour.
Source: Authors' calculations based on data in Castlerock. 2010. *Phase 1 Report.*

If only the projects are built for which costs are below the 9.7 US¢/kWh ceiling, then 1,949 MW would be built. The other 483 MW of geothermal projects in the supply curve exceed the ceiling and would not be built. The incremental costs associated with this level of geothermal development are represented by the area ***A*** under the curve. This area represents the additional subsidy that must be paid to PLN by MoF. For the costs as shown here, this calculates to $142 million per year once all 1,949 MW have been built—assuming the bid tender prices were at the levelized cost of energy as reflected in the supply curve.

Figure 6.2 shows the potential impact of raising the ceiling to 12.5 US¢/kWh, which intersects the supply curve at 2,362 MW. Now the incremental costs increase by the additional amount represented by the areas, ***B*** and ***C*** ($125 million), for a total subsidy of $268 million per year once all 2,362 MW

Figure 6.2: Impact of a 12.5 US¢/kWh Ceiling Price



MW = megawatt, PLN = *PT Perusahaan Listrik Negara*, US¢/kWh = cents per kilowatt-hour.
Source: Authors' calculations.

have been built. Note that this is the subsidy for just the existing projects (1,335 MW) plus 1,027 MW of new projects.[45]

The same methodology can be used for the eastern islands, where PLN's avoided financial cost is 11.5 US¢/kWh. Of the 362 MW in the eastern island supply curve, 235 MW have costs below 11.5 US¢/kWh, and so require no subsidy. There are 127 MW between 11.5 US¢/kWh and the new eastern island ceiling of 20 US¢/kWh, which would require a subsidy of $17 million.

In other words, based on the original Castlerock supply curve data, the total subsidy required to develop such geothermal capacity as lies below the new ceiling prices (2,342 MW in Java and Sumatra at 12.5 US¢/kWh and 362 MW in the eastern islands at 20 US¢/kWh) is $285 million per year.[46]

The Castlerock supply curve reflected 2010 costs, under the presumption of constant prices. But for many projects under development, exploration and delineation drilling has barely begun, but drilling costs in particular have increased significantly since then. The Castlerock estimates of the levelized cost of energy clearly no longer apply.

On the other hand, PLN's avoided costs will also not stay constant. According to the IEA forecast of coal prices (in their current policies scenario), at constant prices international coal prices will rise from $100/ton in 2013 to $110/ton in 2020. As shown in Table 6.3, by 2020 PLN's avoided cost of coal generation in the Java–Bali and Sumatra grids will increase to 8.5 US¢/kWh, and to 9.9 US¢/kWh by 2025.

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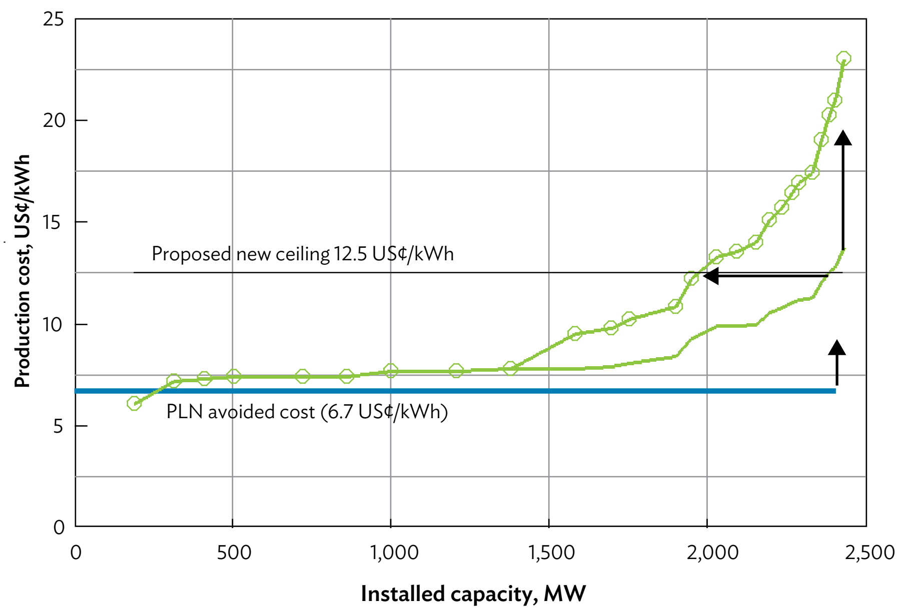
45 That is, 1,335 MW + 1,987 MW = 2,432 MW.

46 The Castlerock report estimated the total 2020 incremental cost at $376 million (under the same assumption that the supply curve reflected tender prices). Castlerock. 2010. *Phase 1 Report*.

Thus, as shown in Figure 6.3, over time both the PLN avoided cost curve (blue) and the cost curve for geothermal projects (green) shift upward as shown in Figure 6.3. But note that as the supply curve shifts upward, the amount of geothermal capacity for any given tariff ceiling decreases (i.e., shifts to the left in the figure, from 2,362 MW to 1,949 MW).

Figure 6.3: Adjusted Cost Curves



MW = megawatt, PLN = *PT Perusahaan Listrik Negara*, US¢/kWh = cents per kilowatt-hour.
Source: Authors' calculations.

Baseline Subsidy Estimates

The impact on subsidy of these two adjustments is shown in Table 6.2. For the proposed ceiling of 12.5 US¢/kWh, the subsidy required is $214 million/year (up from $125 million in the static analysis). However, as noted, at this ceiling price, only 1,949 MW of new geothermal energy is built, down from 2,342 MW in the static analysis.

Table 6.2: Impact of Ceiling Prices on Ministry of Finance Subsidy (Java and Sumatra)

	Ceiling	Installed Capacity	Incremental Capacity	MoF subsidy	Average subsidy	Incremental subsidy
	US¢/kWh	MW	MW	$ million	$/kW/year	$/kW/year
PLN avoided cost (2014)	6.7	186	186	0		
Old ceiling	9.7	1583	1397	120	76	86
Higher ceilings	11.0	1900	317	197	104	243
	11.5	1900	0	197	104	
Proposed ceiling	**12.5**	**1949**	**49**	**214**	**110**	**361**
	13.5	2028	79	248	122	428
	14.0	2094	66	277	132	434
	15.0	2156	62	305	141	450
	16.0	2237	82	348	156	537
	17.0	2292	55	381	166	606
	18.0	2332	40	407	175	642
	19.0	2332	0	407	175	
	20.0	2362	30	430	182	753

$/kW/year = dollars per kilowatt per year, MoF = Ministry of Finance, MW = megawatt, PLN = *PT Perusahaan Listrik Negara*, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

Note that as we move up the supply curve to ever more expensive projects, the amount of subsidy per additional kW increases. At the 12.5 US¢/kWh ceiling, the average subsidy is $110/kW/year. But at 14 US¢/kWh, the average subsidy is $277/kW/year.

There are many uncertainties in this analysis, the most important being the assumption that the tender prices as bid correspond to the levelized cost of energy as in the (modified) Castlerock supply curve. But as noted, declarations of ceiling prices may influence bid prices, and the winning bid could be close to the ceiling price.[47] On the other hand, with up-front Geothermal Fund de-risking, the bid tariff should be correspondingly lower. As discussed in Section 8, the impact on the tariff can range from 1 to 3 US¢/kWh, depending on project size (the smaller the project, the greater the relative impact on the tariff).

Table 6.3 shows the results of alternative assumptions. In column [4] we show the subsidy estimates if bids are at the levelized cost of energy. Column [5] shows the impact of up-front Geothermal Fund de-risking. Column [6] makes the most pessimistic assumption that the bid price will be at the ceiling price, and column [7] at the ceiling price adjusted for Geothermal Fund re-risking. The subsidy impact of the proposed ceiling is seen to be in the range of $149 million to $316 million per year.

47 See discussion at Section 2, Table 2.3.

Table 6.3: Impact of Subsidy on Assumptions (Java and Sumatra)

	Ceiling	Installed Capacity	Incremental Capacity	MoF subsidy if tender prices are at: LCOE	LCOE with de-risking	@tariff ceiling	@tariff ceiling adjusted for de-risking
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
	US¢/kWh	MW	MW	$ million	$ million	$ million	$ million
PLN avoided cost (2014)	6.7	186	186	0	0	0	0
Old ceiling	9.7	1583	1397	120	104	168	152
Higher ceilings	11.0	1900	317	197	141	298	242
	11.5	1900	0	197	141	298	242
Proposed ceiling	**12.5**	**1949**	**49**	**214**	**149**	**316**	**251**
	13.5	2028	79	248	170	345	267
	14.0	2094	66	277	188	368	279
	15.0	2156	62	305	206	388	290
	16.0	2237	82	348	234	413	299
	17.0	2292	55	381	256	428	303
	18.0	2332	40	407	274	438	305
	19.0	2332	0	407	274	438	305
	20.0	2362	30	430	291	445	306

LCOE = levelized cost of energy, MoF = Ministry of Finance, MW = megawatt, PLN = *PT Perusahaan Listrik Negara*, US¢/kWh = cents per kilowatt-hour.
Source: Authors' calculations.

There is additional uncertainty in the supply curve itself. The adjustments made here (increasing the Castlerock cost estimates by 2% per year) are fairly simplistic, and we recommend that the supply curve be updated in detail.[48]

Subsidy to Meet Fast Track Program 2 Targets

FTP2 calls for 4,925 MW of new geothermal projects, none of which are yet completed. The total in the Castlerock supply curves is 2,362 MW in Java and Sumatra, and 362 MW in the east for a total of 2,794 MW, or 1,459 MW of new projects. It follows that to meet the FTP2 targets, another 3,466 MW is required. The subsidy requirements to meet the targets of FTP2 are presented in Table 6.4.

Under the optimistic assumption that the average subsidy cost of these additional projects is the same as that calculated for those in the Castlerock supply curve, then the additional annual subsidy requirement is $601 million, or $428 million with the benefit of up-front de-risking. This brings the total subsidy requirement to meet the FTP2 target to between $774 million and $1,085 million. If the average cost of the additional projects is greater—as would seem likely—the subsidy requirements will be that much higher.

[48] This will require a project-by-project review of the status of development, with updated costs and assessment of drilling prospects, and with updated assumptions about financing structure. Most important, an attempt should be made to extend the supply curve to all of the projects in FTP2. Such a study is outside the scope of this report.

Table 6.4: Subsidy Requirements to Meet Targets for Fast Track Program 2

		No De-risking		With De-risking	
		Annual Subsidy		Annual Subsidy	
	MW	$ million	$/kW	$ million	$/kW
In Castlerock supply curve					
of which <12.5 US¢	1,949	316		251	
>12.5 US¢	483	129		56	
Java and Sumatra	2,432	445	183	306	126
Eastern islands	362	39	108	39	108
Total	2,794	484	173	345	124
Existing	–1,335				
New projects	1,459				
Additional projects	3,466	601	173	428	124
FTP2 target new projects	4,925	1,085	173	774	124

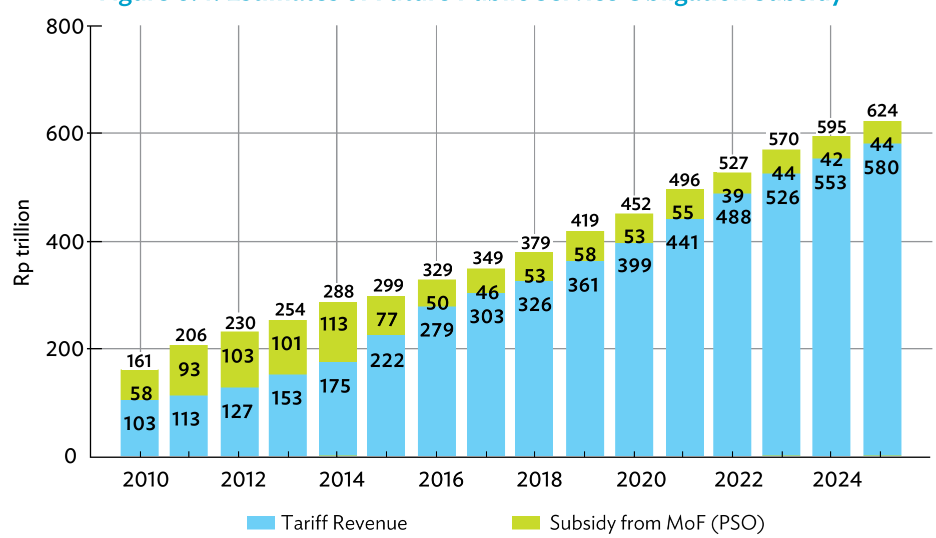
$/kW = dollars per kilowatt, FTP2 = Fast Track Program 2, MW = megawatt.

Source: Authors' calculations.

6.3 Impact on Ministry of Finance

These incremental costs and benefits should be placed in the context of the overall level of subsidy provided by MoF to PLN. Figure 6.4 presents the World Bank's estimates of the PSO derived on the basis of PLN's financial model with a 30-year time horizon. In 2013, PLN's estimated revenue requirements were Rp230 trillion ($23 billion), of which Rp127 trillion was covered by tariff revenue, and Rp103 trillion (or 44%, $10 billion) by the PSO subsidy.[49]

Figure 6.4: Estimates of Future Public Service Obligation Subsidy



MoF = Ministry of Finance, PSO = public service obligation, Rp = Indonesian rupiah.

Source: World Bank estimates based on *Perusahaan Listrik Negara's* 2013 *Rencana Usaha Penyediaan Tenaga Listrik.*

[49] The actual figures from PLN's 2013 Annual Report show revenue of Rp257 trillion, with tariff revenue of Rp153 billion and Rp101 trillion in PSO subsidy.

The actual level of a future PSO subsidy is subject to several key uncertainties, notably assumptions about future tariff increases,[50] and future coal prices. However, there is general agreement that the level of PSO subsidy will decline over the next few years, and by 2020, the PSO subsidy should have fallen to Rp53 trillion ($5.5 billion).[51]

Nevertheless, despite the uncertainty over future PSO subsidy payments, the incremental cost of geothermal subsidies could well reach $1 billion per year if the FTP2 targets are to be met—though this would fall in the event that international energy prices were to increase over the levels envisaged by IEA (Section 4, Table 4.1).

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50 Here we assume 15% tariff increases each in January 2015 and 2016, and 2.75% in each of years 2019–2023.

51 In the PLN financial model, the level of geothermal generation is explicit only for its own projects. Purchases of geothermal energy from IPPs is included in the category "purchased power".

7 Tendering

7.1 The Issues

Revised tariff ceilings as proposed in this report are important, but will not alone unlock geothermal development in Indonesia. The geothermal law requires competition in the selection of geothermal developers, the main features of which are as follows:

- The tender process is conducted under the "two-envelope" system in which the price envelope is opened only after meeting the technical and administrative requirements in the technical proposal envelope.
- In the previous Geothermal Law No. 27/2003, where a WKP or *wilayah kerja pertambangan* (geothermal work area) falls entirely within a single province, the Geothermal Law 2003 devolves responsibility for conducting the tender to the provincial governments concerned. Only where a WKP covers more than a single province was the responsibility assigned to the Ministry of Energy and Mineral Resources (MEMR). Under the new bill on geothermal in 2014, the central government will take over the responsibility of geothermal tender from local governments. While this shift is likely a major step forward, the successful implementation will depend on the capacity of the government tender committee and the regulation on the new tender mechanism.

The current tendering process has several deficiencies. The first set of issues relates to the procedures of tendering, which include:

- poor prequalification standards, which have encouraged unqualified bidders to offer unrealistically low prices that cannot be achieved in practice;
- that the technical capacity of the government tender committees will likely require strengthening;
- that the requirement for the winner of the tender to post a $10 million performance bond has not been enforced; and
- that the presently required bid bond of $100,000–$200,000 is too small, and does not discourage companies from submitting an unrealistic price.[52]

The second set of issues relates to the information available to bidders at the time of tender, including:

- that heretofore the PPA, and its tariff schedules that govern escalation and indexation, have required negotiation after tendering; and
- that the information on the geothermal resource often lacks any subsurface information, making it difficult for bidders to reliably estimate costs. In many cases even basic geology, geochemistry, and geophysics (3G) information is incomplete.

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52 The current requirement is that the bid bond is 2.5% of the estimated first-year exploration program. There is no minimum first-year requirement. Even if the first-year program were $5 million, then 2.5% is just $125,000.

These issues were often mentioned in our discussions with developers, both informally and as expressed at the formal stakeholder consultation meetings (Stakeholder Comment 5). However, these discussions were limited to the prominent developers with a presence in Jakarta, and do not necessarily reflect the views of smaller developers who have won tenders for small projects in the eastern islands.

Stakeholder Comment 5: The Tender Process

Comment:

Chevron has stated that a "meaningful and substantial" bid bond is required, and failed projects should have "meaningful consequences."

Other developers raised similar issues in informal discussions. They are often discouraged from bidding in the smaller projects because they see the tender process as unpredictable; for that reason, they are strongly opposed to "beauty contests" as envisaged by the 2012 FIT under which the *wilayah kerja pertambangan* (geothermal work area) (WKP) would be awarded on grounds other than price. Tender committees in remote provinces are seen as lacking adequate technical credentials to be able to make sound judgements about technical capacity to deliver geothermal projects on time and on budget.

Reply:

We are in general agreement with the comments raised. Our recommendations that the tender process should follow international best practice for competitive procurement address the concerns directly (including better qualified tender committees, and a significant bid bond that will discourage speculators and poorly qualified bidders).

Sources: Written comments from Chevron, received 11 March 2014; informal discussions with developers.

7.2 Evaluation of Past Tenders

The actual number of successful tenders is small. According to data provided by MEMR, in 14 of 21 tenders, there was only one bidder who passed the first stage in the two-envelope system that is used. Again according to MEMR, in all of the 14 cases reporting only one bidder (whose price envelopes were opened), PPA negotiations are underway or already signed. Only one tender is listed as "tender failed." Under the Indonesian rules for tendering, a tender is considered "failed" only if the number of bidders is less than three: if two of the three bidders fail the test of the first envelope, the fact that only one price bid is examined (in the second envelope) does not invalidate the tender.

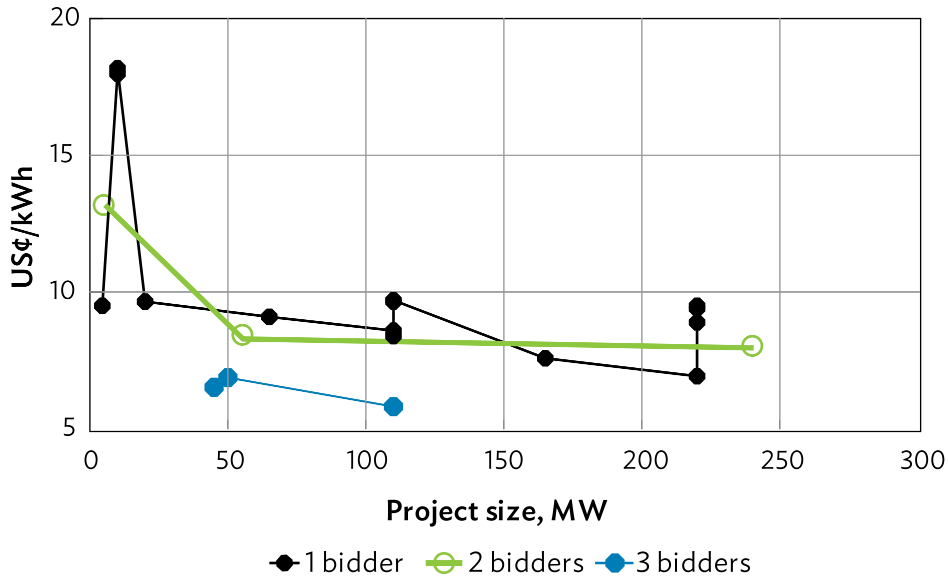
Figure 7.1 shows the bid price as a function of project size and number of bidders.

The sample size is small, so inferences drawn from this analysis require caution. Potential challenges to consider include

- that there is little evidence of scale economies, which could be evidence that bidders have placed little reliance on MEMR estimates of resource capacity;[53]
- that projects with two bidders are not significantly different from those with one;

[53] One possible explanation, particularly for smaller projects, is that bidders have simply acted to secure the concessions in the expectation that they will later decide how much can actually be built.

Figure 7.1: Bid Price versus Project Size and Number of Bidders



MW = megawatt, US¢/kWh = cents per kilowatt-hour.

Source: Data provided by Ministry of Energy and Mineral Resources, January 2014.

- that projects with three bidders have significantly lower prices than those with one or two; however, whether these projects, with bid prices from 5.8 to 6.85 US¢/kWh, can actually be delivered at this price is unclear, and
- that only two of the twenty bid prices are higher than the 9.7 US¢/kWh ceiling.

These findings do support some of the criticisms of the developers. The large number of bids for which just a single price envelope is opened suggests that the system is open to manipulation. With so many obviously unqualified bidders submitting bids to be rejected at the first-envelope stage, the field becomes clear for the one remaining bidder. Moreover, it is fairly clear that the very low bids (even where there are three bidders whose price bids were examined) are very unlikely to be realized.

7.3 Options for Improving the Tender Process

Because the devolution of tendering to the provinces is enshrined in the geothermal law, fundamental changes to the procedure may be difficult, and it is therefore useful to distinguish between the longer term objectives (which may require changes in law), and those that can be implemented in the short-term by regulations issued at the MEMR level.

The Long-Term Objective: Central Tendering

In principle, the question of how to resolve the problems with the tender process is straight-forward to resolve with appropriate technical assistance to develop a set of standards for prequalification of bidders, and for the composition and qualification of tender committees. Such technical assistance has, in fact, been provided by Fichtner under Global Environment Facility funding to the MEMR:[54]

[54] Fichtner, *Consulting Services for Design and Preparation for Geothermal Investment Transaction*, MEMR. Various reports, 2010–2012.

However, in the long-term we believe that efforts should be made to establish a new professional entity for tendering at the center. The rationale for such a new body includes:

- that is much easier to provide technical assistance from multilateral development banks and bilateral donors to an established body with some institutional longevity, rather than to many provincial or municipal and/or regency tender committees that are constituted on an ad hoc basis for short time periods;
- that such a tender committee could also be involved in tendering other renewable projects, particularly hydropower, which has similar problems; and
- that an entity with institutional longevity is in a much better position to deal with post-tender issues as may be associated with adjustments in bid prices warranted for delays that are not the fault of the developer.

An important question would be how the interests of the local governments would be secured (which may be at the provincial, municipal, or regency level). One option would be for the local government to be formally represented on the tender committee.

It may be noted that the present system is not necessarily in the interests of local government, and that there may well be good reasons for them to approve reform of the current system. Simply put, the local benefits of geothermal energy, from direct fees and taxes, as well as from the stimulus to local economic development, are only realized in practice if development succeeds. Unrealistic bids by unqualified developers are not in the interests of local government if these projects fail. They may well be better off if a capable developer is selected, even though they may lose total control in the selection process.

Another long-term goal that may take some time to achieve is to improve the quality of information available at time of tender, for example by using the Geothermal Fund for this purpose (see Section 9.4). In the ideal case at the time of tender:

- a complete and independently verified package of 3G information should be provided;
- the resource should be measured and resource capacity estimated using an internationally accepted method, and
- at least three successfully tested wells should be provided, funded by the state, the costs of which are to be reimbursed at the time of financial closure.[55]

Improving the quality of information available to bidders is particularly important for the smaller projects in the eastern islands.

During the preparation of this report, Indonesia's House of Representative passed the Bill on Geothermal Energy as a revision to the previous Geothermal Law No. 27 of 2003. One of the major changes in the new bill is that the geothermal concession tender and issuance of geothermal license for power development will be carried out by the central government (MEMR). See Appendix 8 for a fuller discussion of the new law.

Options for the Short Term

In general, tendering should follow the practices and procedures of international best practice, as exemplified by ADB and World Bank procurement guidelines. Beyond the two-envelope system already in use, three elements would be vital for Indonesia to adopt in geothermal tendering:

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55 See detailed discussion in Section 8 (which includes provision for recovery of the costs of unsuccessful exploration drilling by the Fund).

- rigorous prequalification;
- requirement for a substantive bid bond (1%–2% of the project cost, but preferably not below $10 million);[56] and
- post-qualification review to ensure compliance of the lowest evaluated bidder with all requirements before winner is announced.

The bid bonds for bidders who do not pass the first-envelope evaluation can be released immediately; the bid bonds for unsuccessful bidders whose second envelope is opened would only be released once the contract with the winner has actually been signed.

This procedure does not necessarily exclude small companies, but the consortia must be in place for prequalification—for which purpose memorandums of understanding will not be sufficient, but would require a credible legal agreement to document the joint venture.

Post-Award Audits

In the Philippines, the winner of any tender by the Power Sector Assets and Liabilities Management Corporation (involving the sale of state assets, including geothermal assets), is subject to a post-award audit by the Privatization Bids Awards Committee, which ensures that all of the tender terms, including the posting of any bond, has been met before declaring a final winner. A similar audit system should be established in Indonesia. Such a review is also part of the normal procedure under the procurement regulations of the IFIs.

Performance Bonds

There is currently a requirement for the winning bidder to post a $10 million performance bond. However, this has apparently never been enforced. There is, obviously, no point in such a requirement if it is not enforced.

It has been argued that one of the reasons why the $10 million bond requirement has not been enforced is the high uncertainty about the actual prospects of a commercial project. For example, the recent KfW report for Bappenas argues the following:[57]

> "Consider the situation in which, after an IUP *(Izin Usaha Pertambangan)* holder conducts verification exploration, the site potential has been overestimated. In that case, the IUP holder may be justified in making the commercial decision not to drill, in which case it should not forfeit the performance guarantee."

However, the problem with this argument is self-evident: the result has been winning bids by unqualified entities. A bidder not prepared to post the recommended bid bond is unlikely to be serious. A complete 3G package (or, better yet, up-front drilling by the government as a public good) mitigates the problem of inadequate information at time of tender.

Developers dislike performance bonds because they tie up (expensive) equity capital. However, a bond requirement is not unreasonable as a pledge of performance in developing the project, but that purpose is surely demonstrated once exploration (or delineation) drilling has commenced. Consequently, it seems reasonable that the bond could be paid down over a 2-year period upon evidence that the equivalent funds have been expended on exploration drilling (in the case where Geothermal Fund has not already provided this), or for delineation drilling.

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[56] The lower bound is for larger projects.

[57] Partnership International, for BAPPENAS. 2013. *The Indonesia Geothermal Handbook*. Jakarta.

Note that tying up equity capital in a performance bond is not without its consequences on the buyer: the cost of raising that additional equity will eventually be recovered by the developer in his tariff. There is no free lunch.

Under our proposed recommendation of a substantive bid bond, the winning bidder would convert his bid bond into a performance bond, to be drawn down as noted above.

Power Purchase Agreement Issues

The tariff schedules of the PPA should be fixed at time of tender, with the same escalation and indexation provisions applicable to all (rather than being the subject of ad hoc post-tender negotiations).

In some cases (notably in the eastern islands), project size is subject to an upper bound because of demand or network constraints. Experience shows that one cannot always reliably predict what the best commercial project size will be, yet this is crucial to make cash-flow projections, because the project's revenue requirements must be recovered across the available kWh sales. Projects that are smaller than expected at tender, for whatever reason, may not therefore be commercially viable at the tariff bid. While one could argue that under these circumstances such a project should be re-bid, the difficulty of valuing any work that has already been done (and what compensation for same, if indeed any, should be provided to the previous incumbent) makes such re-bids difficult.

A preferable solution is to agree, in advance at the time of tender, a formula that would automatically adjust the base tariff price to the actually achievable project size. Section 5 outlines proposals for the procedures by which such adjustments could be made.

PLN may object that its planning—both to ensure the requisite transmission expansion, and to ensure that local loads are met—is made more difficult if project sizes are not fixed in advance. But experience shows that projects that are stalled for inadequate tariffs because projects are smaller than originally planned are an even greater problem—and re-bids imply even greater delays, which are in the interest of neither the developers nor PLN.

Dealing with Delay

Government Regulation No. 70/2010 stipulates that if developers of concessions issued prior to the issuance of Government Regulation No. 59/2007 do not exploit the field by 31 December 2014 (extended from the previous deadline 31 October 2010), they shall have to return the concession to the government. In practice, this applies to Pertamina/PGE and PLN (Ulumbu, Mataloko, and Tulehu), who are the only such concession holders. Deadlines from 31 August to 31 December 2014, for existing holders of mining permits—*Izin Usaha Pertambangan* (mining business permits) (IUP) and tender winners were given by MEMR Regulation No. 17 of 2014. It remains to be seen whether the new deadline will in fact be enforced.

Even if drilling some minimum number of wells within a specified time could be stipulated, good and financially credible developers point out that in many instances, lack of progress is the fault of government, not of developers—an argument well exemplified by the Sarulla project, where sorting out legal issues surrounding asset ownership has taken 10 years. This kind of problem can only be mitigated by resolving the necessary regulatory permits before bidding. This may involve significant preparatory work by the government (and MEMR), but in the absence of precleared sites, there will be no easy solution to enforcing rules about lack of developer progress. The possibility of using Geothermal Fund resources for improving the quality of information available to bidders at the time of tender is available to bidders at the time of tender is set out in Section 9.5.

8 The Tariff Impacts of Front-End De-risking

In the past, the cost of initial exploration in Indonesia has been assumed by the developer, for which only equity is possible since debt finance requires a substantial (and in recent years, increasing) fraction of the required steam resource to be proven in terms of well deliverability. For investors to put up such up-front high-risk equity requires high rates of return, which must necessarily be recovered though the tariff. The objective of this section is to present quantitative estimates of the tariff impact of such front-end exploration costs, since such estimates have not been quantified in previous discussions of front-end de-risking.[58] We assume here that this up-front exploration is undertaken by the Geothermal Fund, as proposed in Section 7.

The costs of exploration drilling to establish the existence of a geothermal resource depend little on the ultimate size of a project. For the sake of illustration, we assume this up-front exploration costs $30 million, including support infrastructure for drilling. The tariff impact of its recovery will depend on two main factors—how many kWh of energy will ultimately be produced, and what is the time lag between exploration and the commercial operation.

Table 8.1 illustrates the necessary calculations. In rows [1]–[11] are shown the developer's cash flows for a $30 million outlay for exploration in the case of a 220 MW project, with COD in Year 8. Assuming a 90% plant capacity factor, 1,754 GWh/year of electricity is available for cost recovery. To achieve the

Table 8.1: Cash Flows for Recovery of Exploration Costs

				NPV	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**30**
1	Developer			r=24%													
2	Exploration outlay	1	$ million	−21.1	−10	−20											
3	Capacity	220	MW														
4	COD date	8															
5	Energy	0.9	GWh				0	0	0	0	0	1,754	1,754	1,754	1,754	1,754	1,754
6	Tariff Impact	**1.30**	US¢/kWh														
7			$ million	21.1			0	0	0	0	0	22.8	22.8	22.8	22.8	22.8	22.8
8	Net cash flows		$ million	0	−10	−20	0	0	0	0	0	22.8	22.8	22.8	22.8	22.8	22.8
9	Equity IRR to developer		[ ]	24.0%													
10	**PLN**			r=12%													
11	Cost to PLN		$ million	−83.2			0	0	0	0	0	−22.8	−22.8	−22.8	−22.8	−22.8	−22.8
12	Net cost to Indonesia		$ million	−83.2			0	0	0	0	0	−22.8	−22.8	−22.8	−22.8	−22.8	−22.8

COD = commercial operation date, GWh = gigawatt-hour, IRR = internal rate of return, MW = megawatt, NPV = net present value, PLN = *PT Perusahaan Listrik Negara*, r = discount rate, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

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58 "De-risking" is perhaps an imprecise term, because the risks of drilling are whatever they are. In this section the term is used in the context of transferring the exploration risk from the developer to other parties, such that the cost to the buyer (PLN) may be reduced. Of course, better 3G data can reduce subsequent drilling risk, but we here assume that a comprehensive 3G data package has been prepared prior to tender.

assumed target 24% internal rate of return (IRR) on such up-front capital requires 1.3 US¢/kWh. The corresponding cost to PLN is $22.8 million per year, or $83.2 million in NPV terms when using the assumed 12% opportunity cost of capital (to the Government of Indonesia) as the discount rate.

Now suppose that the $30 million of up-front exploration expenditure is covered by the Geothermal Fund as a pure public good, with no recovery from the developer. In such a case, the benefit to PLN is a tariff that is 1.30 US¢/kWh lower than in the base case. So the return to government as a whole is also 24%: for every US dollar of up-front geothermal exploration outlay, and assuming that the exploration is successful and leads to a commercially viable power generation project, the implied rate of return on exploration outlays (i.e., the avoided tariff impact if recovered by the developer) is 24%. The net impact (cost) to Indonesia falls to $24.9 million, as reflected in Table 8.2.

Table 8.2: Exploration Costs Funded by Geothermal Fund

		NPV	1	2	3	4	5	6	7	8	9	10	15	20	30
1	Discount rate	r=12%													
2	Geothermal fund outlays ($ million)	–24.9	–10	–20											
3	**PLN**														
4	Incremental cost to PLN ($ million)	0.0			0	0	0	0	0	0	0	0	0	0	0
5	Net impact on government ($ million)	–24.9	–10.0	–20.0	0	0	0	0	0	0	0	0	0	0	0
6	IRR to Govt on GF expenditures	24.0%													
7	Net cost to Indonesia ($ million)	–24.9	–10	–20	0	0	0	0	0	0	0	0	0	0	0

GF = Geothermal Fund, Govt. = government, IRR = internal rate of return, NPV = net present value, PLN = *PT Perusahaan Listrik Negara*, r = discount rate.

Assumptions: 220 MW, COD in Year 9.

Source: Authors' calculations.

The total cost to Indonesia, under the same NPV assumptions as above, falls from $83.2 million to $24.9 million. Such is the difference between private equity funding with recovery 9 years later, and providing high-risk exploration as a public good. It explains why so many countries with substantial geothermal energy development (Philippines, Mexico, New Zealand, Iceland, Kenya[59]) funded a comprehensive geothermal exploration program from the state budget.[60]

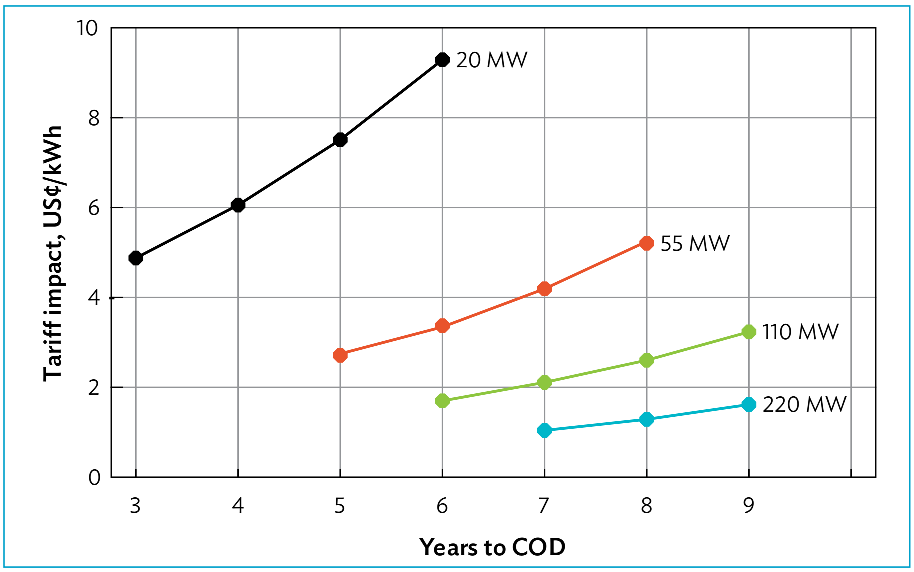
As noted, the tariff impact will be a function of the size of the project, and the time lag to COD. As shown in Table 8.3, for a 220 MW project the tariff impact is between 1 and 2 US¢/kWh; but for small projects, the tariff impact is significantly higher—for a 10 MW project more than 10 US¢/kWh. Of course, for very small projects three successful exploration wells probably means no further delineation or even production drilling is necessary, so time and cost to COD will be much shorter.

59 Though in the cases of Iceland and Kenya, only recently have IPPs been allowed to participate in development.

60 However, the exploration activity was not undertaken as part of the development of a new power project, but as a separate exercise to identify available resources for future development. That was also the situation in New Zealand before deregulation of the power industry. Even in the US, government-funded surveys have been conducted by the US Geological Survey.

Table 8.3: Tariff Impact of $30 Million Exploration Program Funded by Developers (US¢/kWh)

	Installed Capacity, MW				
Years to COD	**220**	**110**	**55**	**20**	**10**
4				4.88	9.76
5				6.05	12.10
6			2.73	7.50	15.01
7		1.69	3.38	9.31	
8	1.05	2.10	4.20		
9	1.30	2.60	5.21		



COD = commercial operation date, MW = megawatt, US¢/kWh = cents per kilowatt-hour.
Source: Authors' calculations.

8.1 Cost Recovery Options for the Fund

The above calculations assume no cost recovery. Ultimately, the cost of geothermal exploration will fall either on government, electricity consumers (through tariff increases), or providers of concessionary finance.[61] From the perspective of government as a whole, it matters not whether the costs fall on the Geothermal Fund run by the government's investment unit or on subsidy provided by MoF to PLN.

However, as discussed below, there exist good reasons to recover the exploration costs where commercial development is enabled. There are two obvious points in the development process at which this might occur: at the time of tender, and at the time of financial closure.

Cost Recovery at Time of Tender

Under the assumption of a successful 2-year exploration program, the work area could be tendered in Year 3, at which point the successful bidder would be required to refund the costs of the exploration to the Geothermal Fund, plus interest. Although in the case of large projects that still require additional delineation drilling this would require equity to do so, with a measured resource a considerable fraction

[61] Note that in the case of concessional finance, where the effective interest rates are far below the government's opportunity cost of capital, some part of the cost is in effect transferred to the global community that provides concessional finance.

of the project risk has been reduced, so the required target equity IRR would be much lower than before the resource is measured. We may assume that at the point of tender, the target equity IRR falls from the 24% assumed previously to 20%, which would be suitable where delineation drilling still needs to be undertaken. For small projects, where the exploration drilling may already provide a significant fraction of the total steam requirement, then a lower equity IRR target would be suitable.

As shown in Table 8.4, this would require a payment from the developer, at time of tender, of $35 million, which the developer recovers at 20% IRR (on his up-front equity) by an increment to the tariff.[62] Under the same conditions as shown in Table 8.1 (220 MW, COD in Year 8), this results in a tariff increment of 0.84 US¢/kWh (compared to 1.3 US¢/kWh if the developer funds early stage exploration himself entirely from equity, Table 8.1). To be sure, this is a substantial up-front payment, but this should be compared with the level of expenditure he would have had to incur during the first few years, had the tender been issued before initial exploration. This also eliminates unserious bidders interested simply in holding the site (as has allegedly occurred in some cases in the past). The net impact on government is $53.3 million, some $30 million less than if developers pay for up-front exploration (Table 8.1, $83.2 million).

Table 8.4: Cash Flows, Cost Recovery at Tender

Recovery through repayment at time of tender																	
				NPV	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**30**
1	Developer																
2	Payment to GF at tender		$ million	−20.4			−35.3										
3	Installed capacity	220	MW														
4	COD	8															
5	Energy	0.9	GWh				0	0	0	0	0	1,754	1,754	1,754	1,754	1,754	1,754
6	Tariff impact	0.84	US¢/kWh														
7	Tariff revenue		$ million	20.4			0.0	0.0	0.0	0.0	0.0	14.7	14.7	14.7	14.7	14.7	14.7
8	Developer cash flows		$ million	0.0	0.0	0.0	−35.3	0.0	0.0	0.0	0.0	14.7	14.7	14.7	14.7	14.7	14.7
9	Equity IRR to developer		[ ]	20.0%													
10	**Geothermal Fund**																
11	Geothermal Fund outlays		$ million	−24.9	−10.0	−20.0											
12	Repayment at tender time		$ million	25.1			35.3										
13	Net impact		$ million	0.2	−10.0	−20.0	35.3	0.0	0.0								
14	*PLN*																
15	Cost to PLN		$ million	−53.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−14.7	−14.7	−14.7	−14.7	−14.7	−14.7
16	Net cost to Indonesia		$ million	−53.3	−10.0	−20.0	35.3	0.0	0.0	0.0	0.0	−14.7	−14.7	−14.7	−14.7	−14.7	−14.7

COD = commercial operation date, GF = Geothermal Fund, IRR = internal rate of return, MW = megawatt, NPV = net present value, PLN = *PT Perusahaan Listrik Negara*, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

The Sarulla project demonstrates that developers are prepared to make substantial payments for access to proven resources at time of tender. Unocal held the original WKP and undertook substantial exploration including drilling, proving two separate good resources (and possibly a third). It then relinquished the concession, for which PLN paid them $60 million. The concession was then

[62] It is assumed that the Geothermal Fund charges interest at 12%, rolled into the outstanding balance at 12% (just like capitalized interest during construction). Therefore, even though the exploration expense was $30 million, the repayment at time of tender would be $35.3 million.

Table 8.5: Cash Flows, Cost Recovery at Financial Closure

				NPV	1	2	3	4	5	6	7	8	9	10	15	20	30
1	**Developer**			r=14%													
2	Payment to GF at FC		$ million	−22.0	0	0	0	0	−42.34	0	0	0	0	0			0
3	Installed capacity	220	MW														
4	COD	8															
5	Date of FC	5															
6	Energy	0.9	GWh				0	0	0	0	0	1,754	1,754	1,754	1,754	1,754	1,754
7	Tariff impact	0.45	US¢/kWh														
8	Tariff revenue		$ million	22.0			0	0	0	0	0	7.9	7.9	7.9	7.9	7.9	7.9
9	Developer cash flows		$ million	0.0	0	0	0	0	−42.3	0	0	7.9	7.9	7.9	7.9	7.9	7.9
10	IRR to developer		[ ]	14.0%													
11	**Geothermal Fund**			r=12%													
12	Geothermal Fund outlays		$ million	−24.9	−10.0	−20.0	0.0	0.0	0.0	0.0							
13	Repayment at financial closure		$ million	24.0	0.0	0.0	0.0	0.0	42.3	0.0							
14	Net impact		$ million	−0.9	−10.0	−20.0	0.0	0.0	42.3	0.0							
15	**PLN**																
16	Cost to PLN		$ million	−28.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−7.9	−7.9	−7.9	−7.9	−7.9	−7.9
17	Net cost to Indonesia		$ million	−29.5	−10.0	−20.0	0.0	0.0	42.3	0.0	0.0	−7.9	−7.9	−7.9	−7.9	−7.9	−7.9

COD = commercial operation date, FC = financial closure, GF = Geothermal Fund, GWh = gigawatt-hour, IRR = internal rate of return, MW = megawatt, NPV = net present value, PLN = *PT Perusahaan Listrik Negara*, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

retendered and Medco–Ormat won the tender despite complications in the bidding process. One of the conditions of tender was a cash payment to PLN of $70 million. The fact that there was then a 9-year delay for other reasons does not undermine this conclusion of willingness-to-pay for access to proven resources.

Table 8.4 also shows the corresponding cash flows to PLN and the Geothermal Fund. With interest included in the repayment to the Geothermal Fund, the net impact on the Fund is a positive (NPV) of $0.3 million. The cost to PLN of the incremental tariff necessary to fund the tender payment at 20% equity return to the developer is now only $14.7 million per year (down from $22.8 million per year if the developer conducts the exploration program at an equity return target of 24%).

Cost Recovery at Time of Financial Closure

Table 8.5 illustrates the cash flows if cost recovery occurs at time of financial closure, assumed here at 3 years prior to COD. Now the costs of fund repayment can be rolled into the debt, and at which point only a small amount of additional equity would be needed. The WACC at this point—post delineation drilling, with the resource proven—will unlikely be greater than 12%, so the tariff impact falls to just 0.45 US¢/kWh.

The net annual cost to PLN falls to $28.6 million, and the total impact on Indonesia as NPV is $29.5 million. If the WACC is based on largely concessional debt, that WACC may be much less—for example at 8%, the total of exploration costs to Indonesia falls to $16.8 million. Table 8.6 compares the tariff impact for a 55 MW project under the various scenarios and as a function of the time to COD.

Table 8.6: Tariff Impact of $30 Million Exploration, 220 MW Project

Years to COD	Developer %	Geothermal Fund Recovery at Tender	Geothermal Fund Recovery at Financial Close
Equity Return, %	**24%**	**20%**	**14%**
	US¢/kWh	**US¢/kWh**	**US¢/kWh**
6	0.85	0.58	0.35
7	1.05	0.70	0.40
8	1.30	0.84	0.45
9	1.61	1.01	0.51

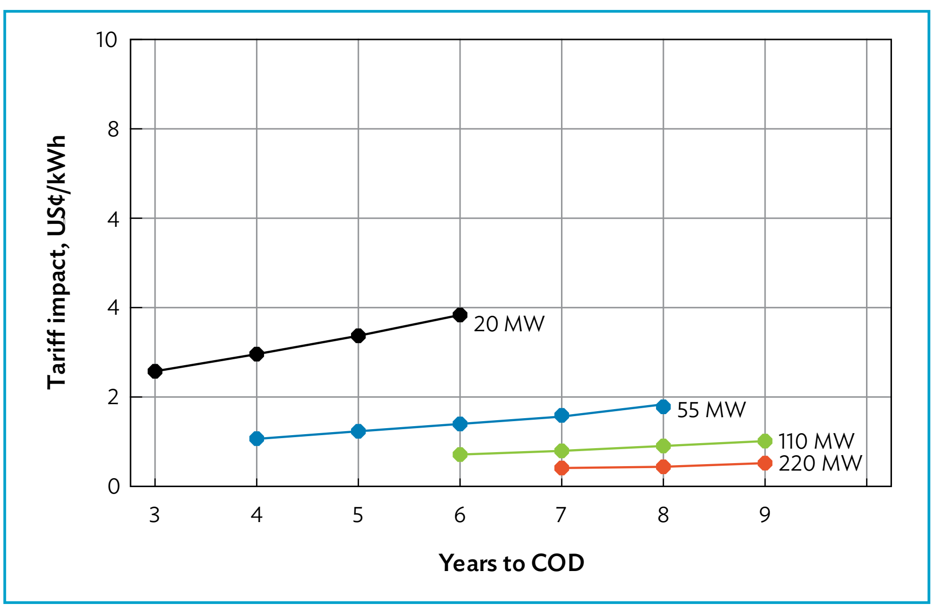
COD = commercial operation date, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

The figure in Table 8.7, drawn to the same scale as Table 8.3, illustrates the tariff impact when exploration costs are funded at time of financial closure. Even for 20 MW projects, the impact is less than 4 US¢/kWh (compared to 6 US¢–8 US¢/kWh if the developer must pay). It explains why so many tenders in small eastern islands have failed or have only had one bidder.

Table 8.7: Tariff Impact of $30 Million Exploration Program, Costs Recovered at Financial Closure at 14% Weighted Average Cost of Capital

	Installed Capacity, MW				
Years to COD	**220**	**110**	**55**	**20**	**10**
3				2.59	5.18
4			1.07	2.96	5.91
5			1.23	3.37	6.75
6		0.70	1.40	3.85	
7	0.40	0.79	1.58		
8	0.45	0.90	1.79		
9	0.51	1.01			



COD = commercial operation date, MW = megawatt, US¢/kWh = cents per kilowatt-hour.

Source: Authors' calculations.

In small projects typical of eastern islands, a successful $30 million exploration program may well mean that most (if not all) of the necessary steam resource has been established: this expenditure exceeds likely bid and performance bond requirements, so the level of remaining risk may be quite small. Nevertheless, unserious bidders would still be discouraged by the requirement to post a significant bid bond.

8.2 Sensitivity Analysis

The above analysis makes several assumptions about which there is uncertainty. First, there is a presumption that the cost (and success) of the exploration program as conducted by developers at their own risk is no different to one conducted by the Geothermal Fund. However, it might be argued that an exploration program conducted by a developer at his own risk would likely be more cost-effective than a program conducted under contract for fee by a drilling company, and managed by a fund—which, as noted elsewhere, lacks geothermal technical expertise.[63] In short, what is accomplished by the fund for $30 million might be achieved by a competent and experienced private developer for 5% to 30% less.

However, as shown in Table 8.8, even at 30% more efficiently, the cost to Indonesia is still more than double that of Geothermal Fund exploration drilling, and with a tariff impact of 0.91 US¢/kWh.

Table 8.8: Impact of Developer Efficiency (220 MW, Year 8)

Ratio of Developer Cost: Fund Cost	Tariff Impact	Cost to Indonesia
	US¢/kWh	$ million
1.0 = $30 million	1.30	83.2
0.9 = $27 million	1.17	74.9
0.8 = $24 million	1.04	66.0
0.7 = $21 million	0.91	58.2
GF 100% funding	0.00	24.9

GF = Geothermal Fund, MW = megawatt, US¢/kWh = cents per kilowatt-hour.
Source: Authors' calculations.

Second, the above calculations are all with respect to a single exploration program that is assumed to result in a commercially viable electricity generation program. That is by no means assured. Consequently, the net impact on Indonesia needs to account for some unsuccessful projects. This has one of two consequences—either the resources of the fund are drawn down (or replenished from the state budget, or even by contributions from donors), or they can be replenished by charging the successful projects a fee.

Such a fee could therefore be levied on all (successful) projects to cover the costs of failed exploration schemes. However, if that fee is payable only at financial closure, at which point there is very little remaining uncertainty in the project, the fee is effectively a pass-through, borne either by the sources of concessionary finance, or by MoF through the PLN PSO.

Table 8.9 shows the impact of the fee on the tariff, under the assumption that it is payable at time of financial closure. The impact is smallest, obviously, for the large 220 MW project—even at 50%, the fee raises the tariff impact from 0.33 US¢/kWh to 0.46 US¢/kWh. For a small 20 MW project, the impact is much greater: a 50% fee raises the cost from 3.65 US¢/kWh to 5.11 US¢/kWh.

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63 Even if expert consultants are engaged by the fund to oversee the drilling program, there is no substitute for a powerful profit motivation.

Table 8.9: Impact of Fee for Unsuccessful Exploration Programs, US¢/kWh (Exploration Cost Plus Fee Paid at Time of Financial Closure)

	Installed Capacity		
	220 MW	**55 MW**	**20 MW**
0%	0.33	1.33	3.65
10%	0.36	1.43	3.94
20%	0.38	1.54	4.23
30%	0.41	1.65	4.53
40%	0.44	1.75	4.82
50%	0.46	1.86	5.11

MW = megawatt, US¢/kWh = cents per kilowatt-hour.

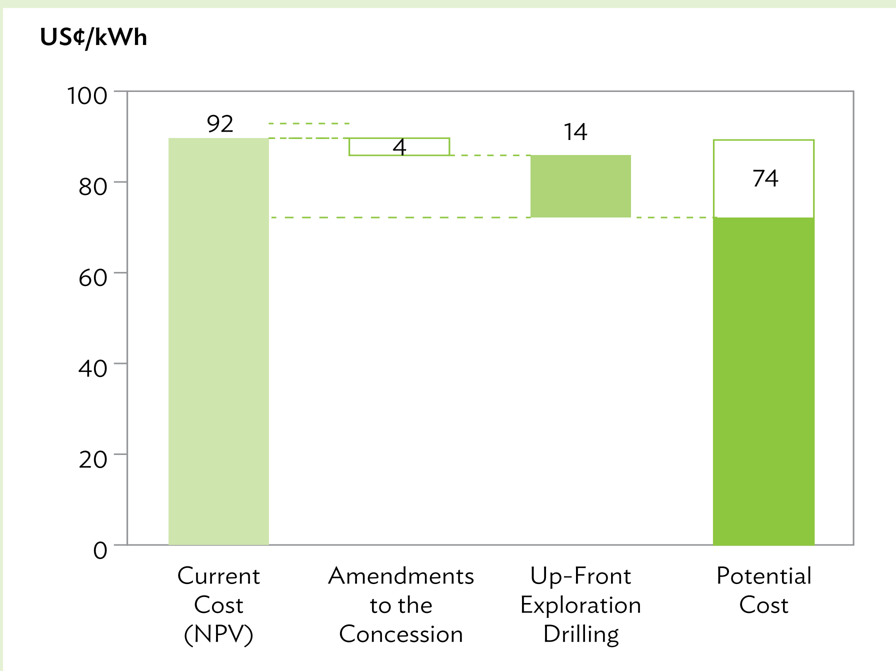
Assumption: weighted average closing costs at financial closure = 12%.

Source: Authors' calculations.

However, what is important is the predictability of the fee, so it can be factored into the developer's cash flow forecasts at time tender. If indeed it is only recovered at the time of financial closure, there is little to no impact on the developer.

Box 8: Impact of Public Funding of Up-Front Exploration in Mexico

A recent study of the impact of up-front exploration funded by the public sector, and improvements to the concession regime, is reported for Mexico. As shown in the figure, the total impact on the tariff was a reduction of 19%, or 1.8 US¢/kWh, comparable to the estimates presented here for Indonesia.



NPV = net present value, US¢/kWh = cents per kilowatt-hour.

Source: SENER. 2013. Initiative for the Development of Geothermal Regime in Mexico.

Nevertheless, there remain the usual questions of moral hazard as applicable to all insurance and quasi-insurance schemes, which applies in this case not to developers (as when occurs for traditional insurance drilling schemes), but to the Geothermal Fund itself. Since the cost of failures can be recovered by the fee, what incentive is there for efficiency in running an effective exploration program? If a drilling contractor is hired by the fund to do the exploration for a fixed fee, he also has no incentive: consequently, there needs to be some bonus system to incentivize the drilling contractor. There are many examples of how to do this within a commercial drilling contract.

8.3 Conclusions and Recommendations

The desirability of up-front exploration being funded by governments has long been noted. The analysis presented here shows just how large is the cost difference between government and private exploration where tariff recovery follows only many years later and explains why so many countries have funded comprehensive geothermal exploration programs from the state budget.

The analysis also shows that by far the lowest cost option is for the fund to recover exploration expenditures at financial closure. This is because at financial closure the repayment to the fund can be rolled into the debt, at which point the relevant cost is the incremental WACC. Depending on what proportion of equity remains to be contributed by the developer, the incremental cost may be just the cost of debt, likely to be significantly lower than the developer's equity return. Indeed, where this cost of capital is below the government's opportunity cost of capital (as will almost certainly be the case if a significant portion of the debt is from IFIs), the net cost of exploration to Indonesia will be lower than if cost recovery is not attempted. Even if additional equity contributions are required, at financial closure the incremental return on equity contributed at that point will be significantly lower than the rate required for additional equity at the point of tender.

Moreover the analysis shows that even if the cost recovery from the development includes a premium for the fund to cover the costs of unsuccessful exploration programs, which do not lead to a commercially viable project and hence to cost recovery, the failure rate could be as high as 60% and the fund could still maintain its nominal starting balance.

The main objective of the Government of Indonesia should be to fund as much of the incremental cost of renewable energy from the IFIs under concessionary financial terms as possible. This is not an unreasonable strategic policy imperative insofar as the main beneficiary of GHG emissions reductions is also the global community.

However, the reality remains that the private sector operations of the International Finance Corporation or of ADB will not lend to projects until the resource is largely proven. With funds from the Clean Technology Fund (CTF), ADB approved a loan to the Rantau Dedap IPP project to support drilling costs on a nonrecourse basis in June 2014. Sovereign operation funds of ADB and IBRD can be used for exploration since these loans benefit from a sovereign guarantee. However, the headroom for such borrowing is limited and MoF is increasingly reluctant to provide these guarantees. Therefore the use of the government's Geothermal Fund as a means to progress project development to the stage wherein upon resource confirmation, IFI debt instruments become available, is an excellent option.

There remains the question of what impact such an exploration program, and cost recovery at time of financial closure, would have on unserious bidders, particularly for small projects in eastern islands. It is true that the recommended scheme would substantially de-risk small projects if a significant part of the steam resource can be established at time of tender, in principle making it easier for unserious bidders to bid (particularly if the costs are to be recovered at financial close rather than at time of tender). However, the best mitigants to eliminate unserious bidders is (i) rigorous technical prequalification; (ii) rigorous evaluation of technical capacity at the first-envelope stage of tender evaluation; and (iii) the requirement for a substantial bid bond.

The recommendations that follow confirm, and further support with quantitative estimates of the benefits, earlier recommendations made by ADB for the Geothermal Fund:[64]

- The resources of the Geothermal Fund should indeed be used to establish a geothermal resource prior to tender, with at least three successful wells.
- The recovery of exploration costs from the commercial developer should be at financial closure, and not at tender: at this point in the development process, a substantial fraction (if not all) of the cost recovery can be rolled into the debt.
- The repayment obligation should include an appropriate interest charge reflecting the government's actual borrowing costs. However, the extent to which an additional fee is necessary to cover the costs of exploration efforts that do not result in commercially viable projects may need further study.
- The repayment that the fund will require at the time of financial closure should be stipulated in the tender document. Since this will be dependent upon the time that elapses to financial closure, the payment should be presented in table form. To provide maximum certainty for the bidder's cash flow projections, a fixed interest rate should be used.

In short, over wide ranges of assumptions, funding of initial exploration by the government, with recovery of some or all of the cost from the developer at the time of financial closure, is the optimum strategy from the perspective of Indonesia. This is true regardless of who in Indonesia bears the ultimate cost—whether PLN and its consumers (once cost-reflective tariffs are attained), or the government (if incremental costs are absorbed by MoF as part of the PSO).

[64] See, e.g., the 2011 AECOM report to ADB that made many of these same points (AECOM, Geothermal Fund Report, Report to ADB, 2011).

9 Institutional and Financing Issues

9.1 Structural Issues

An important problem within the Indonesian geothermal sector is the conflicting objectives of the main government stakeholders in the face of the perceived incremental costs—though as noted, there is much uncertainty about what the actual incremental costs really are. These objectives could be briefly described as:

- ***Ministry of Finance (MoF)*** is concerned about the size of the PSO to PLN, which it regards as increasingly unsustainable. Reducing the magnitude of the subsidy to PLN is its greatest concern in the power sector, which obviously conflicts with the probable incremental costs of geothermal energy, and the need to increase the subsidy to achieve the geothermal targets.
- ***The Ministry of State-Owned Enterprises (MSOE) and state-owned enterprises (SOEs)*** have as their main objective the satisfactory commercial performance of the enterprises, which include both Pertamina and PLN. Consequently, the Pertamina Board of Directors (and in particular the director primarily responsible for investment planning) are reluctant to allocate equity capital to PGE when compared to the much higher returns available in Pertamina's oil and gas plays. While an objective comparison of the resource risk in oil and gas versus geothermal might well conclude that risks are higher in oil and gas, this can be more than offset by the much higher returns. In short, the regulated returns in the electricity sector are not commensurate with the risks of the geothermal business—with the result that PGE faces a continual battle for resources from its parent company.
- ***The Ministry of Energy and Mineral Resources (MEMR)*** sees its role as the promoter of geothermal energy, and is responsible for supervising the sector's development, including responsibility for implementing the Geothermal Law and for tariff setting. It is the entity primarily responsible for promoting geothermal energy, but whether its goals can actually be met is determined by others.

A more nuanced view of MoF's position is that it is not so much the magnitude of the tariff that is of concern; indeed, noted in Box 7 (Section 4), MoF is not averse to green objectives and even carbon taxes. Rather, in the case of the Fast Track Program (FTP) projects that benefit from sovereign guarantees, the concern is that in the event that the guarantee is invoked, MoF officials might stand accused of corruption for causing a government loss, if the selection of the developer cannot be shown to have been properly tendered. In addition, since MoF must provide the necessary subsidy to cover the incremental costs of geothermal, there is an obligation to ensure economic efficiency.

These differences in objectives have not been helped by communication problems between MEMR and MoF in the matter of tariffs in the past. Indeed, basic principles of stakeholder consultation were not followed in the issuance of the 2012 FIT. The result was paralysis: as noted in the introduction, very few additional projects will be added in the next few years. "Wait and see" is the openly admitted posture of Pertamina, PGE, and other significant sectors of the developer community, including the potential commercial partners.

9.2 The Role of the State

In most countries with a large degree of geothermal development, the primary role of the state in the geothermal sector is exploration drilling, then often leaving the development of power generation projects to the private sector at a stage when much of the remaining cost can be raised as debt. But Indonesia has taken a different path, with its Geothermal Law assigning exploration drilling to the private sector as part of the competitive system for bidding WKPs. Indeed, the extent to which the Geothermal Fund can itself undertake drilling is one of the unresolved questions (Section 9.4).

Consistent with the view that geothermal development was a mining activity, Pertamina was given the largest share of geothermal resources and the responsibility for developing them. PGE was subsequently created as the vehicle for accomplishing this objective—though it was Pertamina who recently bid for a concession for Seulawah Agam in Aceh, not PGE. In addition, PT Geo Dipa Energi was established in 2002 to develop fields in Dieng and Patuha, though without being provided adequate financial resources. The reality of geothermal project development is that it requires large amounts of up-front equity, so there is little point in a state-owned geothermal development entity if a clear commitment to provide the necessary equity is lacking.

Ministry of Finance

At present, MoF is not permitted to provide guarantee to PLN payments (a prohibition that is not unique to geothermal projects). Payment guarantees under the FTP1 and FTP2 projects require a waiver through presidential decree. The mechanism for provision of guarantee to PLN is stipulated in MoF Regulation No. 139/2011, 225/2013, and 173/2014. However, given the history of past PLN defaults, the difficulty of obtaining payment guarantee of PLN obligations is an important barrier to geothermal energy development, and needs to be addressed by a new regulation.

A Strategic Vision for the Sector

A coherent government strategic vision for the sector is needed. MEMR generally focuses only on the technical aspects of the sector and not its financial and investment problems. The targets announced for geothermal development, with a list of WKPs and projects to be developed by a particular date, is not always consistent with actual financial and equity investment constraints. Resolving the underlying conflicts existing between MoF, MSOE and/or SOEs and MEMR requires agreeing on the incremental costs of different levels of geothermal energy and how these costs are to be funded. Only when such agreement has been reached will be it reasonable for the government to decide what should be the balance of the state and private sector, and then allocate the necessary investment resources to Pertamina (and PGE), and Geo Dipa Energi, to enable that strategy to be carried out.

Pertamina Geothermal Energy

PGE's fundamental problem is that it is not in reality an independent company, adequately and independently capitalized to undertake the mission entrusted to it. Although it has its own independently audited accounts, and functions by law as a corporation, in reality it is better described as an independent division of Pertamina. It is entirely dependent upon Pertamina for its equity requirements to develop projects. This is perhaps well illustrated by the recent problems at Ulubelu, where it took 18 months to obtain Pertamina approval for additional equity to complete the drilling program after the initial phase encountered a lower success ratio than projected.

It seems evident that Pertamina is reluctant to commit equity capital to PGE to develop geothermal projects when much higher returns can be obtained from the oil and gas sectors. If that is indeed the case, there should be some time limit on Pertamina's legacy concessions, and Pertamina should face limits on bidding on new concessions in the absence of progress on its existing fields.

Nevertheless, if the government wishes Pertamina and PGE to play a meaningful role in the country's geothermal development, then the MSOE should consider setting up a separate benchmark for the equity returns for geothermal projects, and treat geothermal projects as a separate line of business that should not be seen as competing with oil and gas. The rationale for such a benchmark is that comparable equity returns to oil and gas projects would simply increase the MoF tariff subsidy to PLN, and that government should recognize the overall economic returns to country of geothermal investment, rather than the more narrow interest of SOE equity returns.

Geo Dipa Energi

GDE was established on 5 July 2002 to develop geothermal fields in Dieng (Central Java) and Patuha (West Java). GDE currently owns a 60 MW power plant at Dieng (Unit 1) which is inoperable at the moment but under rehabilitation to restore it to about 40 MW. GDE is also planning to commission a 55 MW plant at Patuha (Unit 1) in the third quarter of 2014. GDE became a state-owned enterprise on 29 December 2011, following the passing of Government Regulation No. 62/2011.

Following its new status as a state-owned enterprise, GDE planned a very ambitious expansion plan. In the near term, GDE plans to commission additional units at Dieng and Patuha. Each of these sites is expected to support steam resources that can support a maximum of 400 MW. Since 2013, GDE has received capacity development grant assistance from ADB and Agence Française de Développement (AfD). ADB's assistance[65] focused on enhancing GDE's capacity in safeguards and procurement practices and preparing them to engage with international development banks. AfD's assistance targeted reviewing steam resource assessments at their two locations and preparing an expansion plan. Through this technical assistance, GDE is currently in discussions with ADB and AfD to finance for expansions.

Perusahaan Listrik Negara Geothermal (State Electricity Company)

PLN has a long history in Indonesian geothermal development. The first geothermal power plant which was commissioned in 1983, Kamojang 1, was developed and owned by PLN. PLN owns and operates a number of geothermal power plants with the steam supplied from PGE's geothermal areas. PLN Geothermal was established in 2008 to develop and maintain the upstream activities for geothermal concessions.

PLN and PLN Geothermal hold concessions in the eastern area of Indonesia: Tulehu (Maluku), Ulumbu and Mataloko (East Nusa Tenggara), and Sembalun (West Nusa Tenggara). An integrated upstream and downstream geothermal development for those projects resulted in the power plants at Mataloko (1 x 3 MW) and Ulumbu (2 x 2.5 MW). The projects have provided PLN valuable experience in the geothermal development. However, in 2013 PLN decided to suspend the activities of PLN Geothermal because there are already two other SOEs (Pertamina/PGE and Geo Dipa Energi) engaged in geothermal development on behalf of the state.[66] While PLN Geothermal is still a legally established entity and holds the concession, PLN appears to have plans to continue its geothermal program under PLN's own Renewable Energy Division.

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[65] ADB. 2011. *Technical Assistance for Geothermal Power Development Project*. Manila.

[66] PT PLN (Persero). 2013. *Annual Report 2013*. Jakarta.

9.3 Pertamina Geothermal Energy Commercial Partnerships

Objectives

Largely at the behest of Pertamina, PGE appears to be negotiating a number of proposed commercial partnerships[67] as a way to raise the necessary additional equity that it cannot get from Pertamina in the present fiscal environment. The basic strategy is to establish new project companies in which PGE's equity takes the form of contributed assets rather than new cash—i.e., the value of the preparatory work of site development is already completed. This constraint means that the new entities will be majority-owned (and controlled) by the new partners, with PGE holding only a small minority share.

A second objective is to bring to PGE's operations the partners' presumably superior technical and management capabilities, since the operational management of the projects will be taken over by the commercial partners.

Tariffs

Whether the commercial partnerships will proceed will depend, among other factors, on whether the tariff permits the desired equity return objectives of the commercial partners. It seems likely that these are higher than PGE's equity return targets that were the basis for past agreements on tariff with PLN.

PLN and PGE have jointly commissioned a study by Sinclair Knight Merz Limited to reassess the tariffs necessary for, among others, the proposed Tompaso 40 MW and Karaha 30 MW projects to succeed. After reviewing the tariff assessment proposal, PLN and PGE signed a Heads of Agreement with tariffs in the range of 8.4 US¢/kWh–11 US¢/kWh,[68] as compared to the previously agreed tariffs of less than the old 6 US¢/kWh–8 US¢/kWh ceiling. Such results may well reflect negotiating positions, and depend on key assumptions: one should bear in mind that developers will always claim a regulated tariff is "too low," regardless of what level is proposed. The relatively small sizes of the projects analyzed may have some bearing on the high tariffs. Unfortunately, as of the time of writing, we have not been given access to this report, and therefore cannot comment on its assumptions or the extent to which the results are reasonable.

Availability of Commercial Partners

While the progress or the outcome of the negotiations is unclear, an interesting question is whether there are suitable partners available. To be suitable, partners need to have a strong balance sheet and the ability to raise up to $100 million in equity or nonrecourse debt for drilling; a mandate to participate in overseas projects (which precludes, for example, Comisión Federal de Electricidad of Mexico and some other SOEs); good expertise and preferably a proven track record in geothermal projects; and preferably (but not necessarily) some Indonesian experience. Possible additional candidates could include:

- ***Origin*** (Australia): Origin is suitable given its ownership of Contact Energy, which is New Zealand's largest geothermal generator, and its part-ownership (along with Tata Power of India) of OTP Geothermal, which is undertaking the Sorik Merapi project in Sumatra.

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67 *Think Geoenergy*. 2013. Pertamina to Partner with Chevron and Star Energy on a Project Development. 20 November. http://thinkgeoenergy.com/archives/17192

68 PLN press release. "The Signing of the Head of Agreement (HoA) PLN – PGE about the Basic Price of Geothermal Steam and Electricity Power." 24 April 2014. Jakarta. http://www.pln.co.id/eng/?p=2886

However, it declined to participate in the first round of commercial partnership negotiations, and appears to be giving geothermal a low priority overall.

- ***Supreme Energy*** (Indonesia, with overseas backers): Supreme Energy appears not to have been formally invited to participate in the first round. Supreme Energy is in fact an umbrella for three separate project-specific companies, each with different shareholding, and as such it is not a single potential partnership company. The participants may be already fully occupied with their own three concessions.
- ***Ormat*** (US): Ormat is one of the world's largest geothermal generators as well as equipment suppliers. It is participating in the Sarulla project along with Medco. It has the financial resources and downstream track record to partner with PGE, but perhaps lack upstream credibility. It may also consider that it is already sufficiently exposed in Indonesia already with Sarulla.
- ***Mighty River Power*** (NZ): Mighty River Power is well qualified, being New Zealand's second largest geothermal generator, and has in recent years taken on several overseas projects. However, not all of those projects have gone well and the company has previously mentioned that Indonesia was not in its preferred portfolio.
- ***ENEL*** (Italy): ENEL is suitable, being the world's second or third largest geothermal company, and it has taken on overseas projects in several countries including Chile, El Salvador, and Nicaragua, but lacks Indonesian experience and has not previously expressed an interest in Indonesia.
- ***Calpine*** (US): Calpine is suitably qualified, being the world's largest geothermal company. It has previous experience in Indonesia, but it exited post-1997 and has not expressed any interest in returning, presumably because it regards the country risk as too high.
- ***Other US and Canadian geothermal companies:*** The other US and Canadian geothermal companies are either too small or financially under-resourced to enter the Indonesian market (e.g., Ram Power, Alterra, US Geothermal), or, like Calpine, suffered bad experiences with the PPA defaults in 1997 and are unlikely to return (e.g., California Energy, Florida Light, and Power).
- ***Icelandic companies and consortia:*** There are several Icelandic geothermal companies, some of which are SOE's, some of which are private, and some of which have overseas investors. In the past, Icelandic companies have shown an ability to work together on an ad hoc basis so they are best considered as a group. Icelandic geothermal expertise is world class and companies have aggressively looked for both consulting and investing opportunities in other countries, with strong support from their government. After the 2008 collapse of the Icelandic banking sector they have lacked financial credibility, but more recently have for example started on a project in the Philippines. As a whole, they should be considered serious contenders for partnerships in Indonesia.
- ***Marubeni*** (Japan): Marubeni is an engineering, procurement and construction contractor and generator. It has previously expressed an interest in geothermal projects in Indonesia, has partnered with Supreme Energy for one project, and has adequate financial resources. It lacks in-house upstream expertise but has shown a willingness to contract that in. It could be a serious contender.
- ***Mitsubishi*** (Japan)*:* Mitsubishi has entered the geothermal business by acquiring 20% of Star Energy shares.[69]
- ***Sumitomo*** (Japan): Sumitomo is partnered with Supreme Energy on two of its projects. This is Sumitomo's first foray into geothermal energy development as distinct from

[69] Mitsubishi Corporation. 2012. Mitsubishi Corporation Enters Geothermal Business in Indonesia. http://www.mitsubishicorp.com/jp/en/pr/archive/2012/html/0000017168.html

engineering, procurement, and construction contracting. Through its links with Fuji it has good downstream expertise, but lacks upstream expertise. It is probably waiting to see the results of their participation in Supreme Energy before entering into other geothermal projects in Indonesia.

- ***GDF-Suez*** (France): GDF-Suez is also partnered with Supreme Energy, but in all three of the Supreme Energy projects. It has good downstream expertise in fossil fueled projects, but also lacks upstream expertise. It is also probably waiting to see the results of its participation in Supreme Energy before entering into other geothermal projects in Indonesia.

9.4 Finance

Geothermal energy production is capital intensive, and will require billions of dollars in debt and equity to realize the targets set by MEMR. The cost of exploration alone, for the next 3,000 MW is estimated at $2.8 billion (see Appendix 6) for details. With little of this likely to come from Pertamina, and the present resources of the Geothermal Fund limited (at present) to just $300 million, the bulk of this will need to be raised from the private sector. It remains to be seen whether this can in fact be mobilized.

Financing the downstream power generation project once the resource is confirmed poses few issues unique to geothermal. Off-take risk, readiness of the transmission connection, and guarantee of payment by PLN are common to all IPPs. The technology of power generation using geothermal steam is well established and cost overruns of the type associated with hydropower projects (due to geotechnical and tunneling risks) would be rare.

What is difficult is debt finance of the exploration stage. As noted above, if loans from the Geothermal Fund require 100% collateral, then such "loans" are equivalent to equity.[70] It is not unreasonable to conclude from global experience that the best prospects for successfully developing the geothermal resource is for government to take the upfront exploration risk, and simply tender as IPPs the downstream part—which is the route followed by the Philippines. The Indonesian approach that places that risk on the developer makes the funding of the exploration stage the critical problem.

As long as geothermal development is subject to unpredictable institutional constraints (one again thinks of the Sarulla project), the lack of lender enthusiasm with financing high-risk geothermal projects is understandable. The harsh reality is that what the geothermal sector needs most to facilitate financing is a stable tariff regime, some form of payment guarantee for PLN's off-take obligations, and a predictable regulatory environment.

Our consultations with developers suggests that the larger, established developers are content to assume the exploration risk (i.e., finance with their own equity) for larger projects, but have less interest in the smaller projects in the eastern islands, even if they were de-risked by the Geothermal Fund (as suggested in previous sections). Large developers are only interested in large projects.

Nevertheless, in addition to the $3 billion for exploration, and assuming that the results of exploration will indeed result in an additional 3,000 MW of capacity, with the power generation portion likely to cost at least $2,500/kW, the total financing requirement will be close to $10 billion. Many put the total cost at $4,500/kW, which for 3,000 MW comes to $13.5 billion.

In principle, there is no shortage of potential sources of concessionary finance: the World Bank Group, ADB, IFI, and JICA and JBIC have ambitious plans to provide support, including CTF funds.

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70 It is unclear to what extent this requirement could be replaced by a Bank Guarantee—though such a guarantee would also require a corresponding security.

International Bank for Reconstruction and Development

IBRD can lend to public developers (and public–private partnerships projects) with sovereign guarantees, so there is in principle no reason why IBRD loans could not be used for exploration drilling under the protection of the guarantees.[71] But the question is the extent to which the MoF would be prepared to issue guarantees if it had doubts about the risks for a given project (though all FTP2 projects supposedly qualify for MoF guarantees).

In the case of Ulubelu and Lahendong projects, IBRD is not providing funds for drilling, only for steam-field development and the power plant: funding for drilling has to be provided by Pertamina, and delays in securing such funds have had significant impacts on the projected COD. In this project, MoF is the borrower, who on-lends to Pertamina, who in turn provides (debt) funding for PGE. At present, MoF is not permitted to provide guarantees to funds directly lent to entities such as PGE, though a discussion is currently underway for a mechanism which would permit direct loans to SOEs with MoF guarantees. This would require a new government regulation. Of course, this is not a matter only for IBRD, but one that affects lending by ADB and JBIC as well.

ADB

ADB's experience in financing geothermal projects in Indonesia dates back to 2002. ADB financed PLN's Lahendong Geothermal Power Plant Units 2 and 4 with the government's sovereign guarantee.[72] Building on this experience, ADB prepared a multitranche financing facility (MFF) for multiple projects to PGE in 2011. An MFF requires extensive initial due diligence, but in return it allows additional funds to be disbursed quickly with simplified administrative processes. The MFF was also designed to incorporate the use of CTF to further improve the financial viability of the target projects. However, the disbursement planning of these sovereign loans to SOEs have become subject to parliamentary approval in Indonesia since 2009, and this caused delays in securing financial resources for Pertamina for PGE projects. As a result, the government of Indonesia and Pertamina decided not to pursue any further use of sovereign-backed financing for PGE's geothermal projects. The preparation of ADB's MFF was therefore cancelled in 2012.

ADB later received a request from GDE for technical assistance for its resource assessment and corporate planning in 2012. Through this assistance, GDE and ADB are currently planning a new sovereign-backed loan for its expansion plans. Despite the needs for large financing for its two working areas with a total potential of 800 MW, GDE, as a new SOE, has limited borrowing capacity. Therefore, loans from multilateral or bilateral financing agencies with sovereign guarantees have become the most sensible solution. Since the loans would be sovereign guaranteed, ADB is also able to finance exploration drilling activities, which commercial loans cannot cover.

ADB's Private Sector Operations Department has also been involved in the sector, and the signing of financing agreements between lenders and the developer of the Sarulla project was reached in March 2014. This is the first new geothermal IPP project[73] in the country for over a decade. The funds from CTF are used as mezzanine financing, making the debt package more attractive to allow further acceleration of the development. The involvement of ADB and JBIC (see below) also enabled cofinancing by six commercial banks. Since the MFF was cancelled, Pertamina also approached and mandated ADB's Private Sector Operations Department for a direct corporate loan with CTF for their geothermal expansions in March 2014. ADB's Private Sector Operations Department is in discussions with other IPPs regarding financing with CTF at the various stages of project development, including exploration.

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71 This has been done in some other countries (such as Djibouti in the early 1980s), but it has not always worked well.

72 Both power plants were built under ADB Loan 1982-INO: Renewable Energy Development Sector Project.

73 This excludes expansions such as Wayang Windu 2, completed in 2009.

In addition to the role of sovereign loans, this illustrates another key role of IFI funding in leveraging private lending to geothermal projects. There is only a limited number of commercial financing deals for geothermal energy in the world. More successful cases are required before private lenders can actively provide financing for the sector, and these IFI-backed private projects will lead the way. As long as the regulatory framework, including processes for land acquisition and permissions, allows developers to invest, IFIs are also equipped with financing resources such as CTF to support these projects, as seen in the case of Sarulla.

Japan Bank for International Cooperation

JBIC provided the largest portion of the debt (42%) for Sarulla. JBIC has played an important role in large-scale project financing in Indonesia and will continue to do so for IPP-based geothermal development. It further facilitates the participation of commercial lenders by providing political risk guarantees to cofinanciers. JBIC will likely be the lead bank for any geothermal IPP projects with a significant participation of Japanese developers. However, JBIC normally requires a government guarantee on the off-take agreement with PLN and is likely unable to finance exploration drilling. With its capacity to finance a large portion of the required debt, however, it plays a pivotal role in enabling the financial closure of a project. Therefore, a balanced mixture of JBIC loans and financing for exploration through facilities like CTF would likely be the most effective financing sources for some geothermal IPPs in the short- to mid-term.

Japan International Cooperation Agency

JICA is the public sector peer to JBIC in Japan's bilateral partnership with Indonesia. It has also played an important role in the Indonesian geothermal sector by providing sovereign loans to PLN and PGE. The total commitment made by JICA for Indonesian geothermal projects is over $1.1 billion, the largest among development partners. Similar to IBRD and ADB, JICA's loans have not yet financed drilling activities. Its loans for the Lumut Balai (PGE) and Tulehu (PLN) projects, however, contain portions for exploration drilling. These may be the first drilling activities to be financed by IFIs in Indonesia. JICA's case will, therefore, likely provide important lessons for IFI-financed drilling activities, which will likely be more complicated than sponsor-financed drilling owing to the requirements of IFI procurement guidelines based on international or national competitive bidding. If the Government of Indonesia and Pertamina resume the use of sovereign loans for Pertamina projects, JICA will likely resume its leading role in geothermal financing for SOEs in Indonesia as well.

Stand-By Financing

PGE's recent problems with obtaining the necessary additional capital to fund Ulubelu and Tompaso drilling highlights the need for flexible financing arrangements. There are good models from hydro development that apply here. Hydro IPPs also face considerable uncertainty, albeit not from resource uncertainty but from construction cost uncertainty, especially tunnelling risk. Indeed, some commercial banks will often declare "we take no tunnelling risk." Therefore it is not uncommon, especially in Latin America, for hydro IPPs to arrange for standby financing arrangements triggered by certain geological outcomes that cannot be predicted prior to actual tunneling or dam foundation work.[74] But that can only be arranged if any additional standby equity requirement has also been arranged in advance. It also emphasizes the need for internationally credible resource estimation and reporting. The current arrangements for PGE obtaining additional equity from Pertamina are a case in point: any hope for flexible financing is academic under such conditions for equity.

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[74] World Bank. 2010. Peru – Overcoming the Barriers to Hydropower. *Energy Sector Management Assistance Program Report*. 53719-PE. Washington, DC.

Payment Guarantees and the Role of the Multilateral Investment Guarantee Agency

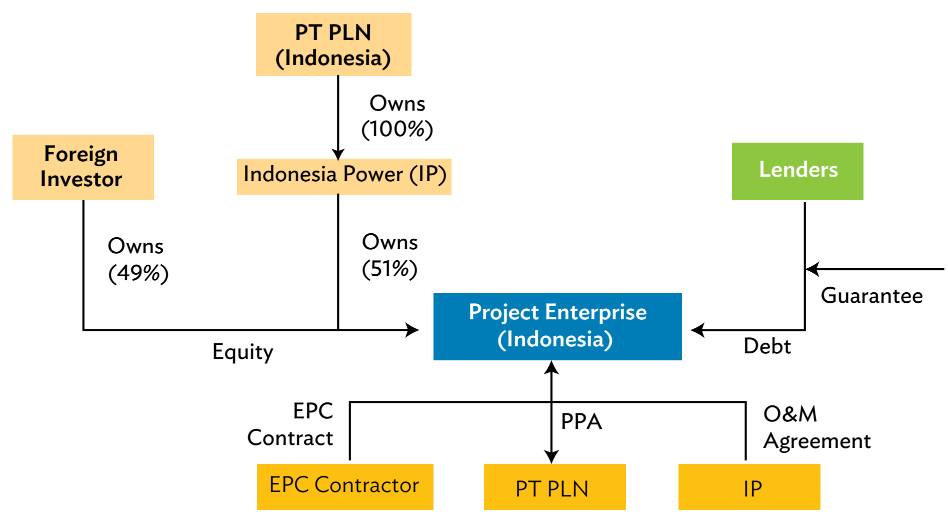
Indonesian IPP development suffered a severe blow in the aftermath of the 1997 financial crisis, as PLN defaulted on some of its payment obligations. Consequently, it is entirely understandable that geothermal IPPs have sought guarantees for PLN's PPA obligations.

Where equity is provided to geothermal projects by foreign investors, there is an opportunity for MIGA to provide assistance. MIGA is designed to insure foreign investors (say Chevron) against default by a state-owned enterprise (such as PLN).[75] While MIGA has not yet done a recent geothermal deal, 36% of its global fiscal year 2013 portfolio is in the power sector, and will be providing guarantees for an Indonesian hydropower project (Figure 9.1). Tenor is up to 15 years, with 20 years on an exceptional basis, and up to 90% of equity, and 95% of debt can be insured. One of the conditions for a MIGA guarantee is a No Objection Letter by MoF to such guarantee. MoF should be ready to provide such a letter.

The cost of a MIGA guarantee varies according to country, sector, transaction, and type of risk. A typical premium for a power project would be 125–150 basis points per year (1.25%–1.5%) for insuring the SOE payment obligation. However, on the strength of MIGA's AAA rating and zero risk classification by the Bank for International Settlements, a MIGA guarantee can lower the cost of debt. With a guarantee in place, a typical financing at the London Interbank Offered Rate (LIBOR) + 500 basis points could be obtained at LIBOR + 350–400 basis points, so the effective net cost may be quite small or negative.[76]

However, because MIGA is limited in the volume that it can provide in the coming year (that applies not just to geothermal IPPs), the guarantee by MoF is vital for new geothermal projects. Until the PLN tariff reaches cost recovery level, lenders will require some sort of guarantee to PLN payments, which

Figure 9.1: Multilateral Investment Guarantee Agency Guarantee to Offshore Lenders: Indonesia Hydro Project



EPC = engineering, procurement, and construction; IP = PT Indonesia Power; MIGA = Multilateral Investment Guarantee Agency; O&M = operation and maintenance; PPA = power purchase agreement; PT PLN = *PT Perusahaan Listrik Negara.*

Source: Multilateral Investment Guarantee Agency, Project Brief. Rajamandala Hydropower Project. http://www.miga.org/projects/index.cfm?pid=1367 (accessed 10 September 2014).

[75] MIGA has two distinct products that potentially apply here: non-honoring of SOE financial obligations, and breach of contract by an SOE.

[76] From MIGA.

MoF needs to explicitly include in its overall support to the sector. As with the case of direct loans to SOEs, a new regulation is required to allow MoF to do so (and to protect MoF officials to make those decisions).

9.5 Geothermal Risk Mitigation

Geothermal Fund

In 2011 the government established a Geothermal Fund, now funded to $300 million. However, a satisfactory model for use of these funds has yet to be developed, and no disbursements have yet been made. A viable model is urgently required, which will require a change in the current regulations of the fund.

One of the proposed disbursement models is based on providing loan funds to developers for up-front exploration drilling. As noted above, such lending conditions are considered onerous, since they are reported to require 100% collateral, in effect requiring equity (which if available, might just as well be used directly for exploration rather than pledged as collateral). For the loans to holders of IUPs to be effective, it is essential that this collateral requirement be revised.[77] However, there is already another financing scheme for government-led exploration before tender in the current regulation for the operation details of the Geothermal Fund. This mechanism is much better structured, and rather than improving the loan scheme for IUP holders, MoF should focus on operationalizing the funding scheme for exploration before tender. This requires careful attention to the shift of tender authority from local governments to the central government under the new bill on geothermal.

A major concern is related to the use (and waste) of government funds for unsuccessful projects: according to the Law of State Finance 17/2003, actions by government officials causing losses to the state, even if merely by negligence, are considered corruption. This principle might be applied to exploration whose costs might ultimately be unrecoverable if a WKP proves not to be commercially viable.

This concern can be mitigated. As suggested by MoF, decisions about which resource areas are to be selected for exploration drilling can be vetted by an independent panel of international technical advisors, who would confirm that, based on the best available surface data, exploration drilling in a particular area was prudent. That would absolve government officials from the charge of negligence. In addition, one may impose a fee on successful projects to make up any potential losses of unsuccessful projects.

Ideally, tenders should only proceed on the basis of measured resources (say a minimum of three wells), for which we recommend use of the Geothermal Fund. The fund would finance exploration drilling as a public good, albeit with recovery of costs at time of financial closure of a project that proves to be commercially viable. Private capital for up-front exploration expenditures is expensive, which will ultimately be reflected in the tariff. Up-front de-risking will not only improve the quality and number of bidders, but result in a lower equity return required by bidders, reducing the tariff. Calculations in Section 8 show that the smaller the project, the greater the likely impact on the tariff (ranging from 1 US¢/kWh for large projects to 3 US¢–4 US¢/kWh for small projects in the eastern islands).

We recognize, however, that it may take some time to find a satisfactory mechanism for using the Geothermal Fund for this purpose, since at present the fund lacks the technical capacity to manage an exploration program. We accept the recommendation of the Indonesia Geothermal Association (INAGA) that the fund resources should be directed in the first instance to the eastern part of

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77 Also as noted previously, there is the question of whether a bank guarantee in the same amount would suffice.

Stakeholder Comment 6: Use of the Geothermal Fund

Comment by the Indonesia Geothermal Association, March 2014:

Relating to the utilization of the Geothermal Fund, the Indonesia Geothermal Association (INAGA) can understand that the Geothermal Fund is used to reduce exploration risk. However, we also need to consider that the energy crisis has to be immediately resolved and geothermal power plant is the part of the Acceleration Program. If the government has to conduct the exploration drilling before tendering out, it will produce better data quality. However, it will also take longer process since the exploration program takes 3–5 years to complete while many *wilayah kerja pertambangan* (geothermal work areas or WKPs) are to be explored, so the acceleration program will be delayed.

Therefore, we suggest using the Geothermal Fund more effectively. The Geothermal Fund should be used for geothermal development in the eastern parts of Indonesia where there is limited investor interest, and therefore government support is required to develop geothermal resources in the area. For other areas where many investors are interested to develop, the Geothermal Fund is not needed since many bidders will participate in the competitive tender process as long as the ceiling tariff is attractive to them.

Reply:

We agree that the first priority should be to improve resource data in the eastern islands, where indeed there would be little interest in the big developers to develop projects below 30 MW. However, the fund's resources should be used to prepare a comprehensive geology, geophysics, and geochemistry package (3G) for all projects prior to tender, regardless of location. And because resources are scarce, a prioritization scheme is needed.

We also agree that it will take time for the Geothermal Fund to establish a workable model for exploration, to establish a new central tender entity, and to establish its technical expertise to be able to manage an exploration program (for which international technical assistance will be required). However, with assistance from the Japan International Cooperation Agency (JICA), a consensus is emerging on the best way forward, in which the exploration program would be managed under a long-term contract to a suitable consulting company on behalf of *Pusat Investasi Pemerintah* (Indonesia Investment Agency) (PIP) and Badan Geologi, with appropriate safeguards to avoid conflicts of interest, and independent certification by international experts. Box 9 presents the JICA-proposed scheme.

Source: Personal communication from INAGA. 11 March 2014.

Indonesia where the interest of the large developers is limited (Stakeholder Comment 6).[78] We also accept the suggestion of Chevron that in the first instance the fund should be directed to ensure the completeness of the government's geological data and to ensure the adequacy and completeness of the 3G information made available at time of tender. However, even this less ambitious activity will require technical assistance, and expert advisors to assist in the interpretation of the data.

Box 9 shows the JICA proposal for the organizational structure for exploratory drilling, with much emphasis on the avoidance of conflicts of interest and the need for independent review to certify results. The details of some of the individual elements still require further elaboration, but the study team supports this general approach.

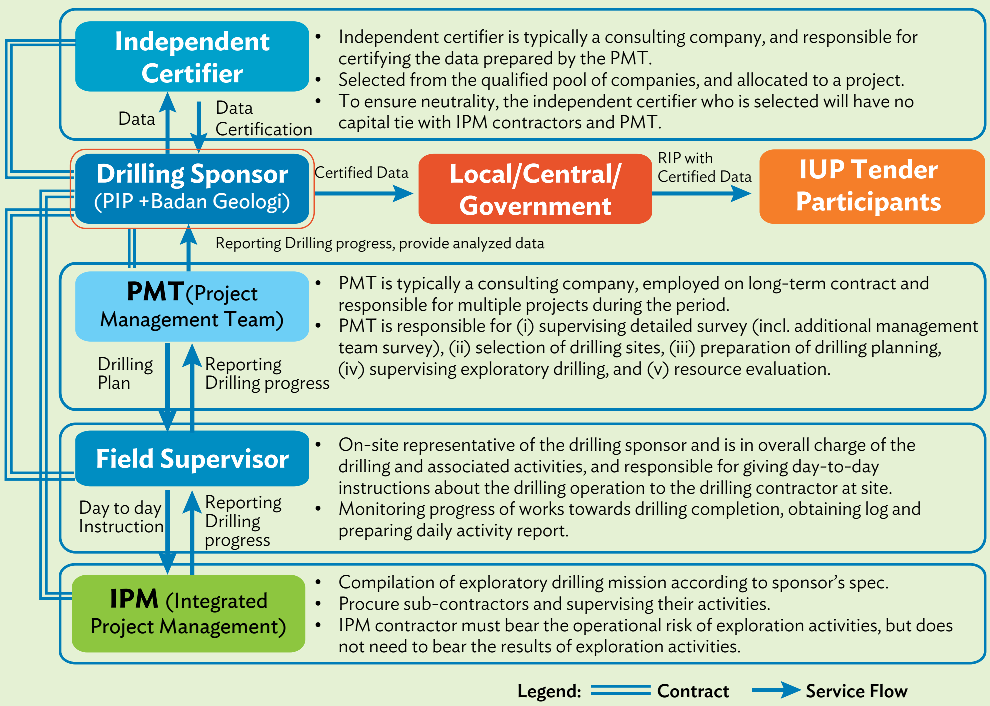
[78] Personal communication from INAGA. 11 March 2014.

Box 9: Proposal for the Organizational Structure for Exploratory Drilling

A viable model for the effective use of the resources of the Geothermal Fund must recognize the following realities:

- *Pusat Investasi Pemerintah* (Indonesia Investment Agency) (PIP), as an arm of the Ministry of Finance, does not have adequate technical capacity to undertake an exploratory drilling program.
- Much of Indonesia's technical expertise in geothermal resource assessment resides in its Badan Geologi.
- For the information to be of real value as a basis for tendering, the geology, geophysics, and geochemistry (3G) and exploratory drilling information must adhere to an internationally recognized reporting code (see Appendix 1), and be independently certified.

Japan International Cooperation Agency-supported technical assistance is preparing a concept for an organizational structure, as shown here:



Key elements of such a structure include:

- a suitably qualified consulting company, under long-term contract to PIP and Badan Geologi, to manage the program and be responsible for multiple projects during the contract period;
- an independent entity to certify results (who may be an individual international expert), drawn form a pool of certified experts, and free of potential conflicts of interest before and after tender; and
- experts drawn from this pool also advise PIP and Badan Geologi on the prudence of committing resources to particular projects, which are then passed to the project management team for execution.

Source: PWC/KRI/Maxeed, Proposed Organization Structure for Geothermal Fund Facility, Progress Report to JICA, January 2014.

Support Mechanisms in International Practice

A variety of support mechanisms are found in international practice, which might be adopted by the fund. These fall into three broad categories: (i) drilling insurance, (ii) direct grants, and (iii) revolving funds.

The objectives of such schemes vary. In some cases, such as many projects in Europe and perhaps to a lesser extent in the US, the objective has been to stimulate commercial geothermal development in a known geological setting with readily quantifiable risks. Therefore, the emphasis is on successful production rather than exploration or innovation. Similarly in Germany, the proposed scheme will initially be applied to well-known areas to gain more confidence in geology and scheme practice. In a later step, new geologies (e.g., North German Basin) and new technologies (e.g., Enhanced or Engineered Geothermal System) will be covered by the scheme. In contrast, in Australia and the African Rift Geothermal Development Program (ARGeo) program, the emphasis was more on exploration and proof of technical concepts, so projects that test a range of geological settings were favored. Most schemes other than the wide-ranging whole-project loans, are designed to operate on a well-by-well basis. The ARGeo scheme has a rollover provision under which the maximum payment reduces from the initial to subsequent wells.

Drilling Insurance

A number of drilling insurance schemes have been tried or proposed worldwide, including the World Bank-supported Geothermal Energy Development Program (GeoFund) for Europe, and ARGeo in Africa. Under the GeoFund, the Geological Risk Insurance program, which is the cornerstone of both programs, is designed to absorb a major portion of that risk by providing insurance against the failure of the reservoir confirmation drilling program to confirm the existence of an economically exploitable geothermal resource. Such economic viability is to be determined on the basis of the temperature, flow and/or pressure, and chemical suitability of the geothermal fluids to allow for power production or in the case of the GeoFund, significant direct use projects (e.g., district energy or industrial process). Criteria for success or failure are to be negotiated prior to the initiation of the drilling activities.

Some level of partial compensation can be awarded for wells that are below the level of anticipated production, but cannot be considered to be eligible for full compensation. For example, if a project is based on an estimated well productivity of 5 MW per well, but in fact proves capable of producing only 3 MW, a partial payment may be made if such terms have been negotiated at the time the agreement was entered into. The coverage applies only to eligible cost factors; any failure is based solely on geological parameters and no coverage is available to cover so called drilling risk for which conventional drilling insurance may be available (Box 10).

One major feature of the rollover provision is that coverage will be available only on a declining basis. For example, only 80%, 60%, and 40% of eligible expenses would be eligible for coverage for each of the three wells. Eligible expenses have not been fully defined at this point in time, but could exclude, for example, excessive mobilization and demobilization costs, infrastructure development costs (roads, pipe lines, etc.). A cap may also be applied to the eligible expenses in as much as the entire budget for the ARGeo Geologic Risk Insurance program is only $12.3 million. This should go a long way in helping to confirm viable geothermal resources and provide the needed incentive for attracting capital for project development.

Some schemes have been funded by governments or development agencies, which effectively provides free insurance subject only to an administrative fee. In other cases such as the unique Munich Re scheme in Germany, which is offered by a private commercial entity rather than a bank or international agency, a substantial premium is charged to fully reflect the risk to the insurance company. In no case is full coverage provided. There is always some excess to the developer (Box 11).

Box 10: The Geothermal Energy Development Program (Europe) and African Rift Geothermal Development Program Schemes

The insurance program is in the form of a contingent grant with no money made available to the recipient of the insurance coverage until such time that the well is deemed to be a failure. To protect both the World Bank and the developer, it is critical that the well is instrumented and all drilling parameters are recorded so that disputes are minimized should there be a call upon the insurance.

In the case of the Geothermal Energy Development Program (or GeoFund),[a] only one project developer has so far received insurance coverage. In this case the primary project sponsor was the Hungarian oil and gas company, MOL. The coverage amount was 85% of eligible expenses and the developer only asked that the coverage be against failure to encounter sufficient fluids to make the project economically viable. The sponsor felt there was no risk that the temperature would not be adequate based on prior drilling for hydrocarbons in the area. After completion of the drilling and well testing activities, the well was deemed a failure based on the lack of flow and the World Bank paid out an amount in excess of $3 million.

The African Rift Geothermal Development Program (ARGeo program),[b] designed to initially serve six East Africa Rift Zone countries, was initiated in 2006. The ARGeo program will provide many of the same types of assistance as the GeoFund. However, there is no direct investment funding window provided in the ARGeo program. A major component of ARGeo is directed toward technical assistance and the focus is upon capacity building, removal of legal and intuitional barriers, and conducting exploration activities.

Under the ARGeo program, the United Nations Environment Programme (UNEP) is in charge of all pre-drilling technical assistance, while the World Bank retains management of the Geologic Risk Insurance Window and also has the ability to provide limited technical assistance to address post drilling issues. Some post drilling issues, however, must receive some attention prior to the initiation of the drilling phase. These include negotiation of the concession or lease agreement and, where outside financing is required, the basis for a power purchase agreement (PPA) which provides project participants with an assurance that there will be a market for the power that may be produced if the drilling phase is successful. Other post drilling technical assistance can be provided for developing business plans and financing packages, and final negotiation of the PPA. A recent addition is an internship scheme where project developers can nominate individuals to receive internship positions with geothermal developers and/or operators in order to gain needed expertise prior to the project coming on line. The cost for the internship is to be borne by the World Bank.

A major new feature of the ARGeo Risk Insurance Window is the so-called "rollover" feature. Upon applying for coverage, applicants can request that the insurance coverage be eligible to be rolled over to as many as three wells if each preceding well is successful. The argument was made successfully that one successful well would not provide sufficient resource information to allow the developer to finance the project or attract additional equity partners. Three successful wells would provide much greater assurance that a viable geothermal resource would be developed for power generation.

[a] World Bank. Geothermal Energy Development Program (GeoFund). http://www.worldbank.org/projects/P075046/geothermal-energy-development-program-geofund-1st-tranche?lang=en

[b] World Bank. African Rift Geothermal Development Program Project (ARGeo). http://www.worldbank.org/projects/P100203/african-rift-geothermal-development-program-argeo?lang=en

Box 11: Private Geothermal Insurance Schemes

The first insurance to enter the market was Munich Re in 2003. The insurance covered the exploration risk of the Unterhaching project. The insurance was established with support and pressure from the state of Bavaria. The premium was more than €1 million (about $1.25 million) and also included a considerable nonclaim refund. Subsequently, insurance brokers (i.e., Marsh and Willis) and insurance companies like Axa, Gothaer, Swiss Re and R&V entered the market. There are both insurance companies acting as a direct, unique insurer of the risk and insurance brokers distributing the risk between one leading and several contributing insurance companies on the market.

Technical drilling risks can be insured on a standard basis. The conditions for an offer of discovery risk insurance on the private market are a mature project preparation and a substantiated geological-technical exploration and development concept of the geothermal project.

As no standards have been established for this kind of insurance yet, the cooperation between project developer and insurer is of major importance. The clear definition of scenarios, best- and worst-cases, measures and procedures is crucial to produce a reliable and transparent policy. Both the drilling concept and the layout of the test program for the certification of results should be specified in advance and form part of the insurance policy. The implementation and continuous revision of those concepts in the light of the actual geological conditions is the responsibility of the project developer and is realized in dialogue with the insurer.

The general concept of the private insurance solutions is to let the customer choose the desired insurance sum according to the expected investment costs. Currently, a premium of at least €1 million is required for an insured sum of about €10 million (about $12.5 million) plus an own risk share (deductible) of about €1 million.

The major downside of such an approach is the lack of such insurance providers worldwide and the very high premiums that any insurance provider would require, especially in new exploration areas.

Outside of Western Europe (France, Germany, Switzerland) the uptake of the schemes has generally been disappointing and in some cases most of the funds have not been used. There are various reasons why that might be so, but the following general issues need to be taken into account for such schemes.

- If the full risk of the insurance cost is to be covered, in most cases that can only be poorly quantified, which makes the schemes unrealistically expensive. The larger developers would prefer to take a portfolio approach and, in effect, self-insure.
- The legitimate cost of wells needs to be carefully established in advance. That can be done by having an agreed schedule of anticipated well costs. A particular issue is what constitutes a reasonable rate for the developer's own input as, for example, if it owns the drilling rig or undertakes the well testing using its own equipment.
- Drilling plans need to be flexible to cope with unexpected subsurface conditions.
- Failures or cost overruns due to mechanical failures or poor drilling practice need to be excluded. That, together with the previous point, implies that a degree of technical supervision be provided by the funding agency.
- "Success" and "failure" of wells must be carefully defined beforehand. That can be covered by careful testing protocols, the cost of which is included within the well cost (as it can be as high as several hundred thousand dollars). There nevertheless remains a potential for abuse. There are anecdotal instances in the US of successful wells being cemented up to claim the insurance, with the developer having nevertheless benefitted by locating the geological targets and proving the resource. One way around that, which was proposed for Chile (but not yet implemented), was that no payout would be made unless the concession was relinquished.

- The above four points mean that the funding agency must have a good deal of technical expertise, either in-house or contracted, and a fair degree of involvement overseeing the drilling process. That all adds to the cost of the scheme. There is also a cost to companies in preparing an application. In the case of the GeoFund and some of the US schemes, this cost could itself be subsidized by the fund, but that is uncommon.
- It is in the national interest that resource data collected during drilling be filed with some central agency such as the national Geological Survey or Ministry of Energy. Developers may wish to keep this information confidential for an embargoed period.
- Fundamentally, there are conceptual difficulties with a scheme that rewards failure (a so-called moral hazard, an issue common to all insurance schemes). When such a scheme was first raised in Indonesia, the larger and more successful developers were opposed to it on the grounds that it would encourage less able companies to enter the industry.

Table 9.1: Summary of Geothermal Exploration Support Schemes Elsewhere

Country/Scheme	Nature	Premium Required	Scope	Cap/project $ million	% Cover	Criteria for Payment
Germany						
Federal	Loan	No	Drilling and heat plant	3.5 per well and 2.8 for the heat plant	80	Completion
	Drilling Risk Cover	No	Drilling	1.8	50% of originally planned costs	Failure
	Exploration Risk Cover	Higher interest rate while drilling, 10%–20%	Drilling	None	80% of drilling costs	Failure
State	Loan	No	Drilling	1.3	25	Failure
Commercial	Insurance	Yes	Drilling		Partial	Failure
Switzerland	Risk cover	No	Drilling and testing		50–80	Failure
France	Risk cover	Yes	Whole project		Up to 90	Failure
Australia	Grant	No	Drilling	4.7	50	Completion
US						
UCCDP	Loan	No	Drilling		20–90	Failure
GRCP	Loan	No	Drilling and geoscience	3	50–90	Failure
Iceland	Loan	No	Drilling and geoscience		60	Failure
World Bank						
GeoFund	Risk cover	No	Drilling		Up to 80	Failure
ARGeo	Risk cover	Yes	Drilling		Up to 80	Failure

ARGeo = African Rift Geothermal Development Program (World Bank), GeoFund = Geothermal Energy Development Program, GRCP = Geothermal Reservoir Confirmation Program (US), UCCDP = user-coupled confirmation drilling program, US = United States.

Notes: Only the more relevant schemes are included in the table.

Drilling usually includes well testing and stimulation (if used).

Source: Authors' calculations.

Direct Grants

The simplest form of support is direct grants for drilling to the developers, regardless of well success. A scheme of this nature was set up in Australia, while a second example is found in the Geothermal Risk Mitigation Fund (GRMF) funded by KfW in East Africa. Issues with this type of scheme include the following.

- No such scheme has covered the full cost of drilling; the level has varied from 30% to 80%. That can pose an obstacle. For example, very little of the Australian scheme was used because developers could not raise the 50% matching funding, in part because of a steep rise in drilling costs there since the scheme was set up. That was exacerbated by a lack of geothermal technical drilling standards in some states of Australia, meaning that petroleum regulations were (inappropriately) applied, adding to the cost.
- What is included in the well costs needs to be defined: for example, infrastructure costs such as roads and water supply may be included. Mobilization and demobilization costs may be substantial and may be spread over several wells.
- As with an insurance scheme, there needs to be a very careful technical and financial evaluation of the applications, which will usually be on a competitive basis. The GRMF scheme may well provide a good benchmark for this process: The first round of application has been evaluated and contract negotiations for the successful projects are underway at the time of writing.
- While payments are not contingent on the success or failure of the wells, there are still criteria and milestones to be met and evaluated.

Revolving Funds

The basic concept of a revolving fund is that a portfolio of projects is supported by way of a loan, and that successful projects repay the funds provided for future revenue, whereas those that are unsuccessful do not.[79] It therefore shares the characteristics of an insurance scheme in that what constitutes success and failure must be defined. Other issues are as follows:

- The risk of nonrepayment is contingent not only on technical success but also commercial success. It is not uncommon for some productive wells to be drilled but the project does not proceed for various reasons, such as a low tariff or permitting difficulties, and therefore there may be no revenue.
- There may be a very long gap between the initial drilling and revenue resulting. Either the funding agency has to cover that gap or interest rates need to be set so low as to remain attractive to the developer.

Implications of Centrally Funded Exploration Drilling

Castlerock suggested that a government-controlled exploration body undertake geothermal exploration in Indonesia, for Indonesia's national benefit and to encourage participation by IPPs. Castlerock proposed funding through concession fees, whereas others have suggested this could be provided by the Geothermal Fund. Another option is to assign one of the existing companies (Geo Dipa or PGE) to undertake this role. In the case of Geo Dipa, since it is already SOE, there is no legal barrier; but there are barriers in terms of adequate capacity and experience and also potential conflict

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[79] This makes it a declining balance fund, unless those that are successful cover the costs of those that fail, which is expensive and creates a moral hazard.

of interest if the company is also allowed to bid for these projects. For PGE, there is a legal barrier since it is not considered an SOE. But all agree that however such a body is set up, it needs to be technically competent and will require expert supervision.

To be beneficial, the body would require a good system for data collection, collation, and archiving—something that has been notably absent in Indonesia so far. Donor agencies have in the past made proposals as to how to improve the situation with a national database.

The question of access to that database is critical: Would it be free, freely available to anyone subject to a fee, or available only to those who prequalified for concessional bidding? And if not free, how would it be priced? In New Zealand there is a similar situation with legacy geothermal data, which is now held by SOE technical agencies that have, in some cases, priced data access so highly that developers have found it simpler and cheaper to repeat the surveys. Australia has taken the opposite approach, whereby all natural resource data collected by government agencies is made freely available, as is that by exploration companies after an embargo period.

Standardization of resource capacity estimates is also important (see Appendix 1). To be of most value, exploration should include the preparation of such estimates. If, as proposed, exploration includes drilling, further issues arise because geothermal wells are not only a source of resource data, but are in themselves both assets and potential environmental liabilities.

Geothermal wells drilled for exploration may, and hopefully should, be usable either for production or re-injection. They therefore have a tangible value, and if projects where such wells exist are to be taken up by a developer, it is likely that the developer would wish to purchase those wells. But there are also good arguments that they should be priced at less than the cost of replacement, because:

- They may not be in optimal or even feasible locations for ready interconnection to a coherent power scheme—they may for example be on the wrong side of a large river valley or other terrain obstacle, or there may be unresolved land access issues for pipelines.
- They may have been drilled at a smaller diameter, or with a sub-optimal casing configuration than a developer would use on its own behalf.
- They may have been sitting unused for many years and undergone corrosion or other degradation, which reduces their working life, especially if not well maintained.

Wells not commercially productive may still have some value for reservoir monitoring. Once again, though, that value is significantly less than the cost of replacement.

Wells also represent a liability. Both productive and commercially unusable wells potentially have the risk of leaking or blowing out, causing damage. For example, a well may be hot and have a large flow rate, but be unusable because the fluid is too acidic or has too high a gas content. In any event, there needs to be regular monitoring and preventive maintenance. Maintenance includes not only the well and its site, but also road access to it, which can be a significant cost in remote locations.

One approach is to require that unsuccessful wells be permanently cemented up and abandoned, but that precludes subsequent use for monitoring. It also precludes the possibility of future conversion of an unsuccessful well to a successful one through stimulation techniques, or simply because an alternative generation technology such as binary becomes economic.

Another approach is to require that the developer purchases and assumes the liabilities for all exploration wells in a field, whether successful or not. This is a simple concept, but cannot prevent the developer from walking away from it altogether in the absence of some kind of performance guarantee or surety.

Finally, some consideration needs to be given as to how the exploration body sets priorities for drilling. Would potential developers be allowed to lobby the exploration body to prioritize areas of most interest to them?

9.6 Technology Paths to Faster Development

In Appendix 5, we discuss a range of technological options to improve cost-effectiveness and achieve faster development. These include:

- **Retrofitting existing projects with binary bottoming plants (BBP):** The economics depend on resource conditions, but in Appendix 3 (and in particular Appendix 3, Table A3.1) we estimate that an additional 490 MW of BBPs could potentially be installed. Since this would not be suitable for competitive tendering, this would be an exception to our recommendation against a technology specific FIT. Such a FIT should be issued by MEMR. This would not apply to new projects, for which a developer is free to propose any technology mix he or she deems suitable for the site.
- **Use of larger units:** Most of the developments, and in particular those planned by PGE, are based around unit sizes of 55 MW. In some cases, there are good reasons why that should be so. However, in other cases such as Ulubelu 3 and 4, where two 55-MW units are to be installed on the same resource simultaneously, there appears to be no good reason to do so instead of installing a single 110 MW unit. Indeed we recommend that in future, tenders should simply reference some total capacity, e.g., 110 MW instead of 2 x 55 MW.
- **Use of units other than new ones:** The biggest obstacle to the use of such plants in Indonesia so far is believed to have been that, in some cases, government and IFI procurement processes, and lenders' requirements, preclude the use of anything other than a newly manufactured plant.
- **Flexibility in development:** There are several instances in the world where plants have been ordered for a particular project and then switched to a different project by the same owner when, for some reason, the original project became stalled or delayed. This included some of the Philippine National Oil Company Energy Development Corporation plants in the Philippines, and others in New Zealand and Nicaragua. Such opportunities will arise opportunistically but may be a means of keeping the overall program moving when there are unexpected difficulties. However, this may also fall foul of IFI procurement and/or financing rules, which require the use of funds for the purposes intended. If a turbine is ordered, say, for Ulubelu, but then used somewhere else, it is no longer eligible to be financed by the World Bank.

10 Unlocking the Sector: Study Team Recommendations

10.1 General Tariff Approach

With regard to general tariff approach, we recommend the following approach:

- Tariffs should continue to be set by tender, but with improvements to the tendering process and PPAs.
- MEMR should issue non-negotiable tariff ceilings based on benefits (which are PLN's avoided costs adjusted for positive and negative externalities).
- We recommend against fixed FITs based on production costs on the grounds of their lack of economic efficiency, except in the special case of retrofitted binary plants.

On the following grounds, we also recommend against tariff ceilings based on estimates of production costs:

- Information asymmetry, since government can never have the same knowledge of costs and technical parameters as developers—and indeed, for precisely this reason, no countries with large geothermal resources have tariffs based on government estimates of production costs.
- Lack of economic efficiency.
- Conceptual difficulty of calculating a ceiling based on assessment of likely project costs.

10.2 The Tariff Process

With regard to the tariff process, we recommend the following:

- Tariff ceilings must be calculated according to a published methodology, so that developers and lenders can assess factors that are likely to change in the future.
- Tariff issuance should not be a one-time measure. Regardless of the basis for tariff ceilings, the tariff should be reviewed annually, no later than 15 December for the following calendar year.
- Ideally this review would be preceded by a draft issuance and a stakeholder consultation meeting to permit stakeholder comments prior to final issuance (consistent with international best practice).
- The annual tariff ceiling review should be based on updated information for PLN's avoided costs.
- The tariff ceilings shall apply only to new projects tendered after the date of issuance of the tariff ceilings.

10.3 Tariff Ceilings

With regard to tariff ceilings, we recommend the following:

- Tariff ceilings should be based on the benefits of geothermal energy, as assessed by the Government of Indonesia.
- Making such ceilings non-negotiable ensures that only projects for which costs are less than benefits are undertaken. This assures economic efficiency and that the subsidy provided by MoF to PLN is for economic projects.
- The economic benefits of geothermal energy are defined by PLN's avoided economic costs of thermal generation, i.e., with all fuel costs assessed at international prices.
- Government will never have as much information on geothermal production costs as developers, while PLN's costs are transparent and can be assessed easily and reliably by MEMR. For this reason, an avoided cost tariff (or tariff ceiling) is to be preferred over one based on estimated production costs.

10.4 Calculation of Benefits

The benefits of geothermal energy should be based on a calculation of benefits (avoided costs) for three general applications:

- Projects that connect to the interconnection systems of Java–Bali and Sumatra, for which the relevant benefit is the avoided cost of coal generation (in large projects);
- Projects on small islands (or isolated grids on large islands), where the alternative for PLN to meet base-load requirements is small coal projects (typically less than 50 MW); and
- Projects on small islands where small coal projects are not practical, usually for logistical or environmental grounds, and where the only practical alternative is diesel generation.

The applicable tariff ceiling category will be published by the tender agency for every tender.

The total tariff ceiling will consist of the following elements of avoided cost (benefit):

- The avoided variable cost of thermal generation;
- The avoided fixed cost of thermal generation (including capital and fixed O&M);
- The avoided global externality cost of thermal generation;
- The avoided local externality cost of thermal generation;
- The avoided costs to MoF of fossil fuel price volatility; and
- The incremental local economic development benefits.

MEMR should assess these costs on an annual basis using data from PLN for the avoided variable cost of thermal generation, the avoided fixed cost of thermal generation, and the incremental local economic development benefits, and from its Geothermal Directorate for the rest.

10.5 De-risking of Projects

We recommend that the de-risking of prospective geothermal work areas prior to tender should be undertaken with the resources of the Geothermal Fund, with revisions to the fund's rules to make them practicable (such as revising the requirement for 100% cash collateral). This would be particularly important for small projects in the eastern islands, where the interest of the larger developers is likely to be small. More specifically, we make the following recommendations:

- At least three successful wells should be drilled and tested prior to tender.
- The costs of such drilling and evaluation shall be recovered from the successful bidder at time of financial closure of the project.
- The amount payable at financial closure shall include an interest charge and a cost recovery charge (the rates for both to be set at the time of tender).
- The costs of the de-risking as incurred by the government shall be deducted from the applicable tariff ceiling for the tender according to the published tariff ceiling methodology.
- The ownership of the wells, including any unsuccessful wells, and responsibility and/or liability for same, shall be transferred to the successful tenderer.

10.6 Power Purchase Agreements

With respect to PPAs, we recommend the following:

- The present system of time-consuming, ad hoc, post tender negotiation of tariff escalation terms should be dropped.
- A single tariff escalation formula should be adopted for all projects (consistent with international best practice for renewable energy project).
- The prospective PPA should be provided at the time of tender. All relevant terms and conditions, and particularly the schedules relating to the tariff, should be fixed in advance.

10.7 The Ministry of Energy and Mineral Resources Geothermal Production Cost Model

MEMR has developed a useful geothermal production cost model. Even though we recommend that it not be used to calculate ceiling tariffs for reasons that we have detailed in this report, we recommend that:

- The model be documented and published, and be made available to stakeholders as a yardstick to assess the reliability of more detailed models (such as the Sinclair Knight Merz Limited model).
- The model be used in any renegotiation of PPAs (as recommended in this report).

10.8 Power Purchase Agreement Renegotiation Policy

Although we recognize that PPA renegotiation should be primarily a matter for the contracting parties, i.e., between PLN and the developer, we believe there is benefit to MEMR issuing a policy statement that sets out the principles that should apply, and the circumstances under which a renegotiation rather than cancellation should be considered. This would be limited to the following cases:

- Delays attributable to the fault of government;
- Projects where delineation drilling after tender shows the project to be significantly larger or significantly smaller than estimated at tender; and
- Projects for which capacity of individual units was stipulated, but where the developer subsequently wishes to install larger units (e.g., build 1 x 110 MW rather than 2 x 55 MW as originally stipulated). The choice of unit sizes should be left to the developer at final design without penalty.

We also recommend that renegotiation should not be permitted in the absence of payment of the performance (bid) bond or actual exploration costs of at least $10 million.

10.9 Transmission Connections

With regard to transmission connections, we make the following recommendations:

- There must be clarity in the treatment of transmission connection costs at the time of tender.
- The published ceiling tariff excludes the avoided cost of transmission for thermal projects.
- In general, the transmission connection should be funded and built by the developer, then handed over to PLN at the time of commissioning for subsequent maintenance.
- Recovery of the incremental cost of the transmission connection, if paid by the developer, should be through a nonescalating tariff adder over 10 years.
- The metering point should be at the generating facility switchyard.
- Transmission losses in the transmission connection shall be the responsibility of PLN. The technical specifications for the connection that may affect the loss-rate shall be stipulated at time of tender. In any event, the line must meet the technical requirements of PLN's grid code.

10.10 Improvements to the Tendering Process

The principles that should apply to tendering have been well established in international practice, as exemplified by the procurement rules of ADB and the World Bank. These should be followed for Indonesia geothermal tenders. In particular there should be a requirement to post a significant bid bond stipulated as a percentage of the total project cost (rather than just a percentage of the first year exploration program).

We recommend that, as a long-term objective, tenders should only be undertaken if at least three wells have been drilled to measure the resource. In addition:

- The PPA shall be provided at time of tender, and its tariff clauses not subject to subsequent renegotiation, except as expressly provided under the PPA renegotiation policy;
- All bids shall be denominated in US dollars; and
- A significant bid bond shall be imposed.

Indonesia should establish a technically qualified central tender entity to conduct tenders on behalf of local governments. The interests of the local governments can be assured by appointing a representative to the tender committee. Such an entity would require significant technical assistance, but the IFIs and bilateral donors would certainly be interested in providing this.

10.11 Performance Bonds

There is currently a requirement for the winning bidder to post a $10 million bond. However, this has apparently never been enforced. There is, obviously, no point in such a requirement if it is not enforced. Developers dislike performance bonds because they tie up (expensive) equity capital, which is not without its consequences on the buyer. The cost of raising that additional equity will eventually be recovered by the developer in his tariff. We recommend as follows:

- The performance bond requirement should be enforced.
- The bond should be drawn down over a 2-year period upon presentation of evidence that the equivalent funds have been expended on exploration drilling (in the case where Geothermal Fund has not already provided this), or expended on delineation drilling where the project has benefitted from the Geothermal Fund de-risking program.
- However, were the winning developer to repay the Geothermal Fund for the de-risking cost at the time of tender award, then there should be no additional performance bond requirement (since the cost of exploration drilling would likely be significantly higher than $10 million).

10.12 The New Tender Entity

It is clear that the present procedure for tendering is often unsatisfactory. This could be due largely to inadequate technical qualifications of tender committees, which has sometimes led to poor quality control of short lists and unrealistic bids by entities which have neither the technical nor financial capacity to deliver. We consequently recommend the establishment of a new central entity that will conduct tenders on behalf of provincial governments and local entities. During the preparation of this report, Indonesia's House of Representative passed the Bill on Geothermal Energy as a revision to the previous Geothermal Law No. 27 of 2003. One of the major changes in the new bill is that the geothermal concession tender and issuance of geothermal license for power development will be carried out by the central government (MEMR). The new bill assures the interests of local government through a production bonus when the power plant starts commercial operation, in addition to applicable local taxes.

10.13 Measuring Resources

Some developers complain about the poor quality of data being offered in the geothermal concession tendering process.[80] INAGA and developers should make use of or adapt the existing Australian or Canadian geothermal reporting codes (which are essentially identical to each other). These have been extensively peer reviewed and are endorsed by the International Geothermal Association (IGA). They have built up a track record of use and validation.

Alternatively, the existing Indonesian Geothermal Standard should be improved to the point where it can serve the same purpose, recognizing that this process would take some time. Use of such a code would ensure that data presented at time of tender meets generally accepted standards on what constitutes a measured resource.

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80 As noted at stakeholder consultation meetings and in discussions with individual developers.

10.14 Binary Bottoming Plants

With respect to binary bottoming plants (BBP), we recommend the following:

- MEMR should encourage the installation of BBPs at existing projects, where resource quality is suitable.
- It is not technically or commercially appropriate for such retrofits to be subject to a competitive tender.
- Therefore, MEMR should issue a separate production cost-based FIT, also to be reviewed annually, and also subject to the tariff ceilings, which would apply only to such retrofitted projects. This is an exception to our general recommendation against production-cost based FITs in favor of competitive tendering, but this applies only to the expansion of existing projects by BBP, for which competitive tendering is not suitable.
- Proposals to increase the capacity of an existing project by the addition of BBP shall be subject to the adequacy of the power evacuation capacity of the transmission line, and on small island systems of the ability of the system to absorb the extra base-load power, and hence be subject to approval of PLN. The developer shall have the option to pay for any reasonable incremental network costs imposed on PLN, but such costs shall not affect the offered BBP tariff.

10.15 Other Required Supporting Actions of Government

Other required supporting actions from the government include:

- If the government wishes Pertamina and PGE to play a meaningful role in the country's geothermal development, then the MSOE should consider setting up a separate benchmark for the equity returns for geothermal projects, and treat geothermal projects as a separate line of business within Pertamina that should not be seen as competing with oil and gas. The rationale for such a benchmark is that comparable equity returns to oil and gas projects would simply increase the MoF tariff subsidy to PLN, and that government should recognize the overall economic returns to country of geothermal investment, rather than the more narrow interest of SOE equity returns.
- MOF is not permitted to provide guarantee to PLN payments (a prohibition that is not unique to geothermal projects). Payment guarantees under FTP1 and FTP2 projects requires a waiver through presidential decrees. However, given the history of past PLN defaults, the difficulty of obtaining payment guarantee of PLN obligations is an important barrier to geothermal development, and needs to be addressed by a new regulation.

10.16 Recommendation for Further Study

This report argues that a key to the successful development of a geothermal development policy in Indonesia is knowledge of the resource supply curve. The 2010 Castlerock study should be updated, and include a detailed examination of the likely costs based on the current situation. This should follow the probabilistic techniques used in the original Castlerock report. However, it should not be limited to estimates of the levelized cost of energy, but also take into account the likely financial costs. This work should be initiated as soon as possible.

Appendix 1
Reporting Codes

Many developers complain about the poor quality of data being offered in the geothermal concession tendering process. Estimates of the magnitude of the available Indonesian geothermal resource vary greatly. The 2007 West–Japan Engineering Consultants study estimated the exploitable potential across 50 fields at 9,000 MW.[1] As noted previously, in 2011 MEMR's Geological Agency revised the country's geothermal potential to 29,215 MW from 27,000 MW a decade earlier—indeed, the 27,000 MW figure is cited in many World Bank reports,[2] and appears to be the basis for claims that Indonesia possesses 40% of the world's geothermal resources.[3]

The basis for these various estimates is unclear, for it is sometimes not fully appreciated that a resource is only that portion of a natural occurrence (whether of energy, petroleum, or minerals) that can feasibly and economically be extracted. Without the basis for such an estimate being made explicit, including assumptions as to the technology pathway and power prices, it is essentially meaningless. There is a widespread perception that the estimate is too large, but no better estimate has been made, so no one knows by how much.

At the level of an individual geothermal resource, one needs not only to have a good grasp of the size of the resource for planning the development, but it is equally important to have the reliability of that estimate quantified, so that risks can be assessed and financing issues identified.

An Indonesia-specific geothermal estimation methodology was produced as an Indonesian standard (SNI 13-6169-1999) in 1999 and has been subject to two subsequent revisions in 2000 and 2004. It is not clear whether that standard was rigorously applied for producing the 27,000 MW estimate, and it is certain that it has not been used for the inflated estimates on which some of the *wilayah kerja pertambangan* (geothermal work areas) (WKP) tendering has taken place, as pointed out by Castlerock.[4]

The Indonesia Geothermal Association (INAGA), which is affiliated to the International Geothermal Association (IGA), has reported that they are considering developing a new Indonesia-specific geothermal estimation standard, related to the P1, P2, P3 categories used to report the quality of a petroleum resource. The intention of that is commendable, but it may not be particularly helpful in that it will undoubtedly take significant time to develop and validate, and, at least initially, will not have any international recognition, limiting value for resource certification as a basis for financing. Furthermore, to be of much value, it would have to represent a substantial extension of the existing standard, which lacks default parameters for estimation and is weak on standards for reporting (as opposed to estimation methodology).

Rather, it is recommended that INAGA and developers be encouraged to make use of, or adapt, the existing Australian or Canadian geothermal reporting codes (which are essentially identical to each other). These have been extensively peer-reviewed and are endorsed by the International Geothermal

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1 West Japan Engineering Consultants. 2007. *Master Plan Study for Geothermal Development in the Republic of Indonesia*.

2 World Bank. 2011. *Project Appraisal Report*.

3 J. Wilcox. 2012. Indonesia's Energy Transit: Struggle to Realize Renewable Potential. *Renewable Energy World.Com.*

4 Castlerock. 2010. *Phase 1 Report*.

Association (IGA). They have built up a track record of use and validation. That they are applicable to the Indonesian situation is demonstrated by the fact that they have been used in three feasibility studies sponsored by the World Bank,[5] and at least one other significant feasibility study leading to an important investment decision by an independent power producer (IPP).[6] Stakeholder Comment A1.1 summarizes our replies to views expressed, and Box A1.1 enumerates the specific issues in the current Indonesian standard.

Before rushing to judgment about the causes of the slow progress in reaching the announced targets, one may well ask whether the problem lies in the targets themselves. If what is realistically available (at a reasonable price and where there are no grid or market constraints) is only 2,000 MW, then the existing achievement of 1,335 MW would be quite satisfactory. Indeed, with 1,335 MW of capacity installed, Indonesia ranks third in the world, behind only the United States (3,400 MW) and the Philippines (1,900 MW).[7]

At the end of 2012, the installed capacity of geothermal electricity generation in Indonesia was 1,335 MW. The national energy policy[8] stipulates that by 2025, 5% of total primary energy supply shall be from geothermal, translated by the government's Road Map for Development Planning of Geothermal Energy as 9,500 MW. Ministerial regulation of MEMR 15/2010 lists the specific power plants to be developed by the government's Fast Track program (FTP), which total 3,967 MW by 2014. Taking into account other projects not listed in Ministerial regulation of MEMR 15/2010, but known to be under development, the target increases to 5,710 MW.[9] The current *PT Perusahaan Listrik Negara* (State Electricity Company) Investment Plan *(Rencana Usaha Penyediaan Tenaga Listrik 2012* [Electricity Power Supply Business Plan] 2012) now anticipates total additions of 3,611 MW between 2013 and 2020, to bring the total by 2020 to 4,816 MW.[10]

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5 Lumut Balai, Ulubelu, and Tompaso.

6 Star Energy at Wayang Windu.

7 Followed by Mexico (1.0 GW), Italy (0.9 GW), New Zealand (0.8 GW), Iceland (0.7 GW), and Japan (0.5 GW). REN21. *Renewables 2013. Global Status Report*. Frankfurt.

8 Presidential Decree No. 5/2006.

9 Castlerock assessment of geothermal targets, December 2010.

10 PLN. 2012. *Rencana Usaha Penyediaan Tenaga Listrik 2012–2021* (Electricity Power Supply Business Plan). Jakarta. Table 5.11.

Stakeholder Comment A1.1: Use of International Code

The following comments were made by the Indonesia Geothermal Association (INAGA) during discussions.

(1) Indonesia already has its own code [implying that use of an international code is not necessary].

Reply: Indonesia has a national standard produced in 1990 plus several updates, which is specific as to terminology and methodology but which is not a code in the sense of defined minimum requirements for reporting in terms of transparency and materiality. (There are requirements in the 2005 revision and templates for reports about the resource characteristic, but not about the assumptions and methodology used for the resource capacity estimate). It is currently under revision and the revised version has not yet been made public, so there is uncertainty about what it actual means and when that uncertainty will be resolved, nor has it been internationally peer reviewed, nor ratified. We also note that the Indonesian standard does not appear to have been used (or if it has been used, not in a transparent way) in resource capacity estimates on which current tendering and forward planning is based. That issue is extensively covered in the appendixes to the Castlerock report, where rigorous resource estimates using very similar methodology to that in the Indonesia standard end up with much lower figures than the "official" estimates.

(2) The Australian and/or Canadian code is based on mining practice.

Reply: The code has used some terminology from similar mineral codes but that is all. The methodology for resource estimation is geothermal-specific and draws heavily on the Society of Petroleum Engineers (SPE) practices. To quote the Australian code:

> "The Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC) have jointly proposed definitions of standard terms for booking petroleum reserves. Their guidelines for the Evaluation of Petroleum Reserves and Resources (SPE and WPC, 2001) are drawn upon significantly here for methodology, as is the more recent Petroleum Resources Management System (SPE, WPC, American Association of Petroleum Geologists [AAPG] 2007)."[a]

(3) The Australian code has not been adopted by the International Geothermal Association.

Reply: That is not quite correct. The Australian code has been reviewed by the International Geothermal Association (IGA) and endorsed, if not yet accepted as an IGA standard. The IGA Reserves and Resources Committee has also agreed that the Australian code will be used as the basis for an international set of definitions on renewable energy to be developed in the very near future for the United Nations Framework Classification (2009) renewables framework under development by the United Nations Economic Commission for Europe. The work of alignment is underway and is intended to be complete within the first half of 2014.

(4) It would therefore be better to adapt the present Indonesian code if in fact needed.

Reply: In principle we have no objection to the use of the Indonesian standard, and the World Bank Group would be happy to collaborate with INAGA and/or MEMR to revise the standard to make it suitable for this purpose.

[a] As quoted in J. Lawless. 2010. Geothermal Lexicon for Resources and Reserves Definition and Reporting. Adelaide: Australian Geothermal Energy Group. p. 3.

Box A1.1: Specific Issues in Current Version of Indonesia Standard

Some specific issues with the current version of the Indonesian standard are as follows:

- There is only a Bahasa Indonesia version. To be credible to international investors, there also needs to be an official English version. That is particularly the case since some of the terminology does not align well with international practice. For example, in the Indonesian standard there is a resource category called: "Cadangan Terduga" which would usually be translated as: "Contingent Reserves." But the criteria for that category do not include drilling and well testing. The term "reserve" is usually only used for the highest category of geothermal, petroleum, or mineral resources. For example, the Australian code requires that well deliverability has been demonstrated to be able to declare a "reserve." The equivalent Joint Ore Reserves Committee mineral code requires in effect a bankable feasibility study be conducted, and Society of Petroleum Engineers for petroleum restricts the use of "reserve" to resources which can be brought into economic production within 5 years or less. So the Indonesian terminology seems well out of step with world practice.
- The Indonesian standard is essentially one-dimensional. It enumerates a progression of increasing categories of geological and other knowledge about the resource, starting from regional scale surface studies and culminating in drilling and well testing. In contrast, the Australian code and most other resource reporting systems in geothermal, mineral, and petroleum are two- or three-dimensional. In the Australian code, the first axis is geoscientific certainty, as it is in the Indonesian standard, whereas the second axis relates to project feasibility through consideration of issues such as economic, marketing, environmental, social, legal, and regulatory factors.
- While the 2004 revision of the Indonesian standard does include a reasonably comprehensive list of data to be collected, factors to be considered, and report outlines for an exploration program,[a] it does not require explicit disclosure of the assumptions that go into a resource or reserve capacity estimates. These assumptions include the technology pathway, the basis for selecting values for resource parameters such as area and temperature, and the modifying factors that can render an otherwise feasible project uneconomic such as concession tenure and environmental issues. In contrast, the Australian code explicitly requires the disclosure of these assumptions through the concepts of transparency and materiality. A fundamental principle of the Australian code is that a report on a resource capacity estimate should contain sufficient information for an independent authority to check the validity of the assumptions made and to replicate the estimate with a reasonable degree of accuracy. That would not be possible for reports prepared under the Indonesian standard.
- There is no requirement under the Indonesian code for the person producing an estimate to be competent or qualified—nor accountable. In contrast, the Australian code is explicit in these matters, including minimum years of experience in the type of geothermal system being assessed. The parent association maintains a register of competent persons. Inclusion on the register requires agreement to conform to a defined code of ethics. It would be possible (and desirable) for the Indonesia Geothermal Association (INAGA) to take a similar role in Indonesia.
- The Indonesian standard permits the use of the volumetric method (stored heat) and numerical simulation to estimate reserves and resources, which is appropriate. For stored heat, while the 2000 revision of the standard lists preferred or default single values (within broad reservoir temperature bands) for various parameters such as recovery and conversion factors at various resource and reserve categories, and does allow the use of other values, it provides no guidance on how those values should be selected. In contrast, for example, the Australian code lexicon provides default values for:
    - Electricity conversion factors as a function of reservoir and ambient temperature, along with guidance on the relationship of conversion factors to technology pathway (in contrast, for example, the default factor of 10% in the Indonesia standard for a 125°C resource and 90°C cut off temperature is quite unrealistic).

continued on next page

Box A1.1. *continued*

- Recovery factors as a function of rock type, porosity or fracture density based on international peer reviewed research. Unlike the Australian code, the Indonesian standard does not distinguish between the minimum reservoir cut-off grade for stored heat (i.e., the minimum temperature below which a portion of the reservoir should not be included in the resource), and the base temperature for energy extraction. As explained in the Australian code lexicon, those temperatures can differ by 100°C or more, and perhaps more significantly, the difference between them can vary greatly from project to project depending on the technology pathway chosen, so a single default value even for the difference is not appropriate.

- The Indonesian standard, while it gives a description of the numerical simulation process, gives no guidance on how a numerical reservoir simulation model should be used to determine resource capacity thereby through eventual failure criteria for the project (e.g., pressure or temperature). See Clotworthy et al. (2010)[b] for a discussion of this issue.

- The Indonesian standard does not address issues related to probabilistic estimates, which are commonly used for stored heat estimates (and less commonly for numerical resource simulation). Without consideration of how to apply a probabilistic approach, the Indonesian standard cannot provide the basis for the World Bank's recommendation for basing tenders on P90 resource estimates. Most investors would expect the use of probabilistic estimates or at the very least declaration of the uncertainty of the estimates. To quote the Australian code:

> "In most situations, rounding to the second significant figure should be sufficient. For example: 31 thermal megawatts and 6.5 electrical megawatts. There will be occasions, however, where rounding to the first significant figure may be necessary in order to convey properly the uncertainties in estimation. This would usually be the case with Inferred Geothermal Resources. To emphasize the imprecise nature of a Geothermal Resource estimate, the final result should always be referred to as an estimate not a calculation. Competent Persons are encouraged, where appropriate, to discuss the relative accuracy and/or confidence of the Geothermal Resource estimates. Where a statement of the relative accuracy and/or confidence is not possible, a qualitative discussion of the uncertainties should be provided. Use of probabilistic estimates is encouraged."[c]

Notes:

[a] Although there is a far more detailed list of criteria in the Australian code, Appendix D.

[b] A. W. Clotworthy, J. V. Lawless, and G. Usher. 2010. What is the End Point for Geothermal Developments: Modelling Depletion of Geothermal Fields. Proceedings of the World Geothermal Congress. Bali. 25–29 April.

[c] Australian Code for Reporting of Exploration Results, Geothermal Resources and Geothermal Reserves. 2010. The Geothermal Reporting Code (Second Edition). Australia.

Appendix 2

Transmission Interconnection Costs

What are the typical costs of transmission interconnection for geothermal projects? Table A2.1 shows transmission connection costs as estimated by *PT Perusahaan Listrik Negara* (State Electricity Company) (PLN) in the 2012–2021 in its investment plan. We note considerable variation in distance (from 1 km to 80 km) and in cost (from less than $1 million to $8 million).

Table A2.1: Transmission Interconnections, Geothermal Projects

From	Province	MW		Conductor	km	Cost	COD	Status	Cost	Cost
						$ million	Year		$/kW	$1,000/ km
Wayang Windu	Jabar	220	150 kV	2 cct, 2xZebra	32	6.11	2014	Proposed	28	191
Lawu	East Java	165	150 kV	2, 2xHawk	32	2.44	2019	Planned	15	76
Wilis/Ngebel	East Java	165	150 kV	2 cct, 2xZebra	60	5.91	2018	Proposed	36	99
Arjuno Welirang	East Java	110	150 kV	2 cct, 2xHawk	74	5.65	2019	Planned	51	76
Ijen	East Java	110	150 kV	2 cct, 2xZebra	60	5.91	2019	Proposed	54	99
Baturaden	Jateng	110	150 kV	2 cct, 2xZebra	20	1.97	2018	Planned	18	99
Tangkuban Perahu I	Jabar	110	150 kV	2 cct, 2xZebra	5	0.49	2018	Proposed	4	98
Rawadano	Banten	110	150 kV	2 cct, 2xTACSR410	30	4.5	2018	Proposed	41	150
Gunung Ciremai	Jabar	110	150 kV	2 cct, 2xZebra	40	3.94	2019	Planned	36	99
Bedugul	Bali	100	150 kV	2 cct, 1xHawk	4	0.22	2017	Planned	2	55
Tangkuban Perahu II	Jabar	60	150 kV	2 cct, 2xZebra	10	0.99	2017	Proposed	17	99
Umbul Telomoyo	Jateng	55	150 kV	2 cct, 2xZebra	16	1.58	2019	Planned	29	99
Guci	Jateng	55	150 kV	4 cct, 2xZebra	20	3.94	2018	Planned	72	197
Iyang Argopuro	East Java	55	150 kV	2 cct, 2xZebra	60	5.91	2017	Proposed	107	99
Ungaran	Jateng	55	150 kV	2 cct, 2xZebra	30	2.96	2018	Planned	54	99
Gunung Endut	Jabar	55	150 kV	2 cct, 2xZebra	80	7.88	2019	Planned	143	99
Patuha	Jabar	55	150 kV	2 cct, 2xZebra	1	0.06	2014	Ongoing	1	60
Cisolok Sukarame	Jabar	50	150 kV	2 cct, 2xZebra	60	5.91	2017	Proposed	118	99
Tampomas	Jabar	45	150 kV	2 cct, 2xZebra	35	3.45	2018	Planned	77	99
Karaha Bodas	Jabar	30	150 kV	2 cct, 2xZebra	20	1.97	2016	Committed	66	99
Kamojang	Jabar	30	150 kV	2 cct, HTLSC (1xHawk)	1	0.15	2016	Proposed	5	150
Cibuni	Jabar	10	70 kV	2 cct, 1xHawk	50	2.77	2016	Proposed	277	55

$/kW = dollars per kilowatt, $1,000/km = thousand dollars per kilometer, cct = circuit, COD = commercial operating date, km = kilometer, kV = kilovolt, MW = megawatt.

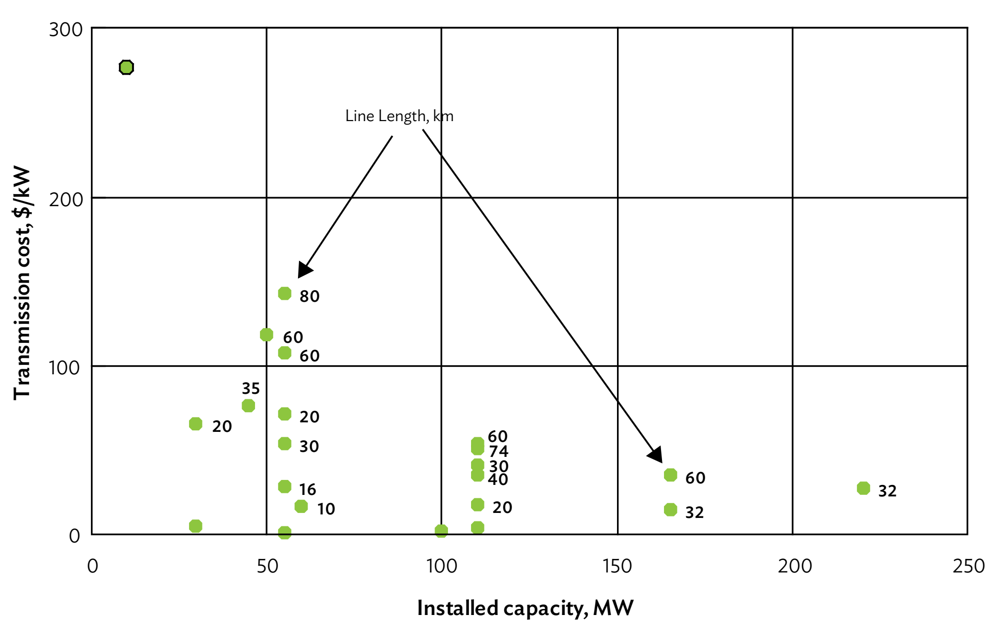
Note: The terms Hawk, Zebra, TACSR410, and HTLSC refer to conductor types.

Source: *PT Perusahaan Listrik Negara* (State Electricity Company of Indonesia). 2013. *Rencana Usaha Penuyediaan Tenaga Listrik* (RUPTL) (Electricity Power Supply Business Plan 2012–2021). Jakarta.

With one or two exceptions, the cost per MW is very small, with an average of $46/kW (if one excludes the outlier Cibuni, $277/kW). Compared to total project costs of $3,500/kW or more, the transmission interconnection cost should not have a significant impact on the bid tariff, were responsibility for the interconnection passed to the developer.

As shown in Figure A2.1, there is some evidence of scale economies—larger projects have somewhat lower transmission costs (as $/kW). We note that most lines are double circuit Zebra, irrespective of the intended MW capacity or distance, suggesting that the transmission configuration has not been optimized for capacity, but probably more for commonality.

Figure A2.1: Transmission Cost in $/kW versus Installed Capacity



$/kWh = dollar per kilowatt-hour, km = kilometer, MW = megawatt.
Source: *PT Perusahaan Listrik Negara* (State Electricity Company of Indonesia). 2013. *Rencana Usaha Penuyediaan Tenaga Listrik* (RUPTL) (Electricity Power Supply Business Plan 2012–2021). Jakarta.

Transmission Connections for Thermal Generation Projects

The average cost for interconnection of large coal projects is $27/kW, so significantly lower than for geothermal projects (Table A2.2). This is probably due to the cost being spread over a greater line capacity, with greater configuration optimization and generally easier terrain than for many of the geothermal projects.

Table A2.2: Transmission Interconnections (500 kV), Large Coal Projects

			Length	Cost	COD	Status	Cost	Cost
	MW	Conductor	km	$ million			$/kW	$/km
Jawa-5	2,000	2 cct, 4xZebra	20	8.30	2018	Planned	4.2	415
Banten	625	4 cct, 4xDove	40	13.06	2016	Committed	20.9	327
Jawa-6	2,000	2 cct, 4xZebra	80	56.44	2021	Planned	28.2	706
Jawa-1	1,000	2 cct, 4xZebra	116	48.14	2017	Planned	48.1	415
Indramayu	1,000	4 cct, 4xDove	200	65.28	2017	Proposed	65.3	326
Jawa-3	1,320	2 cct, 4xZebra	20	8.30	2017	Planned	6.3	415
Adipala	660	2 cct, 4xZebra	28	11.62	2014	Ongoing	17.6	415

$/km = dollars per kilometer, $/kW = dollars per kilowatt, cct = circuit, COD = commercial operating date.

Source: *PT Perusahaan Listrik Negara* (State Electricity Company of Indonesia). 2013. *Rencana Usaha Penuyediaan Tenaga Listrik* (RUPTL) (Electricity Power Supply Business Plan 2012–2021). Jakarta.

The impact on the tariff can be calculated in the usual way, that is: Given an assumed number of kWh over which the transmission tariff can be recovered, what transmission tariff is necessary to meet the opportunity cost of capital? Assuming a 2-year construction time immediately prior to the commercial operation date of the generating station, and an average capacity factor for coal projects of 80%, the incremental impact of the tariff calculates to a negligible 0.05 US¢/kWh. This is about 1.8% of the avoided fixed costs of thermal generation at large projects (Section 4, Table 4.3).

Appendix 3

Project Review

In late 2010, Castlerock estimated a realistic target would be additions of 600 MW by the end of 2014, and 1,400 MW by the end of 2016. Four years have elapsed since then, so it is timely to review those figures, as shown in Table A3.1. This review starts from the Government of Indonesia's stated geothermal development plan as of July 2013. Then new estimates of the probable capacity and completion date for the stages shown are given. In terms of capacity, considerable weight has been given to the Castlerock[1] estimates, since those were based on a systematic re-examination of the data on a consistent basis. In some cases the Castlerock estimates have been further modified here on the basis of additional data that was not available to it at the time. This has led both to increases and decreases. Where the estimated resource capacity is larger than the planned development stage (e.g., for developments on remote islands with a small market), the planned development does not represent the full resource capacity. It is assumed that all MW figures are net at the transmission interface.

In terms of timing, where development is well underway—as for Ulubelu units 3 and 4—a specific estimate of commercial operations date (COD) can be given. In other cases the estimate is based on the stage of development of the project and the regulatory process. Castlerock gave a detailed breakdown for the timing of new projects, assuming that the overall time for a project would be 6–9 years depending on the regulatory process followed. For the present purpose, if there is no other more specific information available a slightly simpler approach has been taken, since the details of the current status of some of the projects are not available, with the following assumptions as to time to COD from the defined present status:

- Significant number of wells drilled, power purchase agreement (PPA) finalized, financial closure or close to it: 2 years. This is based on the assumption that a power plant cannot be ordered until financial closure is achieved and from that point the time for construction and commissioning will be about 2 years.
- Some wells drilled, commercial arrangements advanced, source of funding for remaining drilling identified, PPA finalized or under negotiation: 3 years.
- A few wells drilled, concession tendered, surface exploration complete: 4 years.
- No wells drilled and/or concession not tendered: 7 years.

Obviously if exploration so far has not been promising, longer times will apply.

The next two columns of the table list possible additional generation from bottoming binary plants (Appendix 5). The following assumptions are made:

- No bottoming binary is assumed at the dry steam fields (that are less suitable for bottoming binary plants).
- Only a small amount of bottoming binary is possible at the very high enthalpy fields such as Wayang Windu and Dieng.

[1] Castlerock Consulting. 2010. *Phase 1 Report: Review and Analysis of Prevailing Geothermal Policies, Regulations and Costs.* Jakarta: Ministry of Energy and Mineral Resources.

- Otherwise, for liquid dominated fields, a bottoming binary capacity of 15% of the condensing steam generation is possible.
- Where the binary capacity would be less than 5 MW the possible capacity is calculated but it is not included in the total. Binary plants smaller than 5 MW are available, but it is considered less likely that adding very small binary plants would be considered worthwhile.
- Where the project is on an isolated island and the plant capacity is thought to be driven by the market size rather than the resource size, no binary is added.
- For existing plants or those well advanced in the engineering, procurement, and construction process, it is assumed that an extra 12 months would be needed to add a binary plant. But for plants which are only at the conceptual planning stage, it is assumed that binary could be installed simultaneously with the main plant.

The binary additions listed are genuinely additional to the main plant capacity, and can be assumed to operate through the lifetime of the project. Therefore they offer a real opportunity to accelerate the program.

It is also possible to add early generation by back pressure plants (see below), which may be a good opportunity to accelerate the program and add confidence in the resources, but the assumption is that those would eventually be replaced by condensing plants, so they do not represent permanent additions to the capacity and so are not included in the table. In terms of quantities, one might expect to install such plants when one third to one half of the drilling is complete, and they produce half as much electricity per unit quantity of steam, so the generation available might be in the range of 10 to 20% of the main plant.

The final column of the table gives a brief comment on the current status of the project so far as can be determined, including the following definitions:

- ***Surface exploration*** includes all geoscience prior to drilling. Note that this can cover a wide range of activities from early reconnaissance through to detailed geophysics. Exploration that requires the latter is designated as “advanced” exploration. Logically, surface exploration should be complete before drilling commences, but this is not always the case.
- ***Shallow drilling*** means shallow and/or small diameter drilling, sometimes called “slim-hole” drilling, but excluding very shallow temperature gradient boreholes (which are occasionally but not very often used in Indonesia). A slim-hole can add valuable resource information, which may raise or lower the resource potential. But if a shallow and/or slim hole is not productive, this does not necessarily mean the resource is not viable.
- ***Exploration drilling*** means a program of one to four full diameter wells has been drilled, which may or may not have been commercially successful.
- ***Part drilled*** means that a significant proportion of the wells required for the full planned development have been successfully completed.

Table A3.1: Project Status

	Project	Probable Capacity by Date	Possible COD Date	Cumulative	Additional Binary Capacity	Binary Date	Cumulative Binary	Total	Status
		MW		MW	MW		MW	MW	
1	Kamojang 1	30	1983	30			0	30	
2	Kamojang 2	55	1987	85			0	85	
3	Kamojang 3	55	1987	140			0	140	
4	Darajat 1	55	1994	195			0	195	
5	Salak 1 & 2	120	1994	315	18	2014	18	333	
6	Salak 3	120	1997	435	18	2014	36	471	
7	Salak 4	197	1997	632	30	2014	66	697	
8	Darajat 2	95	2000	727			66	792	
9	Wayang Windu 1	110	2000	837	5	2014	71	907	
10	Lahendong 1	20	2001	857	3	2014	74	930	
11	Mataloko	2.5	2004	859			74	933	
12	Darajat 3	110	2009	969			74	1,043	
13	Lahendong 2	20	2007	989	3	2014	77	1,066	
14	Kamojang 4	60	2008	1.049			77	1,126	
15	Sibayak	13.3	1998/ 2008	1,063			77	1,139	Significant resource issues probably preclude expansion
16	Wayang Windu 2	117	2009	1,180			77	1,256	
17	Lahendong 3	20	2009	1,200	3	2014	80	1,279	
18	Ulumbu	5	2012	1,205			80	1,284	Drilling complete
19	Lahendong 4	20	2012	1,225	3	2014	83	1,307	
20	Ulubelu	110	2012	1,335	16.5	2014	99	1,434	Running at ~80 MW because of resource constraints but those should be solvable

	Project	Probable Capacity by Date	Possible COD Date	Cumulative	Additional Binary Capacity	Binary Date	Cumulative Binary	Total	Status
		MW		MW	MW		MW	MW	
21	Mataloko	5	2013	1,340			99	1,439	Drilling complete (not confirmed)
22	Ulumbu	5	2013	1,345			99	1,444	Drilling complete (not confirmed)
23	Dieng	40	2014	1,385			99	1,484	Not currently operating; may be repaired to 80% capacity
24	Ulumbu	5	2014	1,390			99	1,489	Part drilled
25	Ulumbu 4	2.5	2015	1,392			99	1,491	Field drilled, but not necessarily this part
26	Lumut Balai 1 & 2	110	2016	1,502	16.5	2016	116	1,618	Part drilled but low success
27	Sarulla 2 (Silangkitang)	80	2016	1,582	6	2017	122	1,704	Part drilled, successful but small field
28	Kamojang 5	30	2014	1,612			122	1,734	Drilling complete
29	Ulumbu 5	2.5	2016	1,615			122	1,736	Field drilled, but not necessarily this part
30	Ulubelu 3 & 4	100	2016/2017	1,715	15	2018	137	1,851	Part drilled, moderate success, may be pushing limit of field capacity so down-rated
31	Muara Laboh	110	2017	1,825	16.5	2017	153	1,978	Exploration drilled, some success
32	Sarulla 1 (Namora-I-Langit)	220	2017	2,045	33	2017	186	2,231	Exploration drilled, some success, but difficult terrain, high gas, acidity
33	Sungai Penuh	110	2017	2,155	16.5	2017	203	2,357	Drilling just started; surface exploration advanced; part in national park
34	Karaha	30	2017	2,185	4.5	2018	207	2,392	Part drilled, moderate success, total capacity probably larger than shown
35	Wayang Windu 3	110	2017	2,295			207	2,502	Part drilled, moderate success
36	Lahendong 5 & 6	40	2017	2,335	6		213	2,548	Part drilled, low success, pertamina threatening to stop
37	Jailolo	10	2017	2,345			213	2,558	Not yet drilled, surface exploration advanced, potential market may be larger if mining goes ahead

	Project	Probable Capacity by Date	Possible COD Date	Cumulative	Additional Binary Capacity	Binary Date	Cumulative Binary	Total	Status
		MW		MW	MW		MW	MW	
38	Lumut Balai 3 & 4	110	2018	2,455	16.5	2018	230	2,684	This part not drilled yet, surface exploration advanced
39	Margabayur	55	2018	2,510	8.25	2018	238	2,747	Surface exploration advanced but not drilled within lumut balai wkp
40	Hululais	110	2018	2,620	16.5	2018	254	2,874	Exploration drilled, drilling problems
41	Rajabasa	110	2018	2,730	16.5	2018	271	3,000	Not yet drilled, land access issues
42	Cibuni	10	2018	2,740			271	3,010	One exploration well. Next to patuha - boundaries not clear
43	Wayang Windu 4	110	2018	2,850			271	3,120	Part drilled, moderate success
44	Patuha 1	110	2014	2,960			287	3,247	~50% drilled
45	Atadei	5	2018	2,965			287	3,252	Shallow drilled, resource may be larger than market
46	Hu'u Daha 1	20	2018	2,985			287	3,272	Not yet drilled, surface exploration advanced, market may be larger if mines can be supplied
47	Sokoria	15	2018	3,000			287	3,287	Shallow drilled, surface exploration advanced
48	Seulawah Agam	55	2019	3,055	8.25	2019	296	3,350	Shallow drilled, may be smaller demand than planned
49	Sorik Merapi	110	2019	3,165	16.5	2019	312	3,477	Not yet drilled, surface exploration advanced otp proceeding slowly, may be serious technical issues and some volcanic risk
50	Rantau Dedap	220	2019	3,385	33	2019	345	3,730	Part exploration drilled, should be a good field
51	Suoh Sekincau	220	2019	3,605	33	2019	378	3,983	Not yet drilled. Suoh and sekincau are 2 separate fields, may be technically difficult
52	Jaboi	7	2019	3,612			378	3,990	Not yet drilled

	Project	Probable Capacity by Date	Possible COD Date	Cumulative	Additional Binary Capacity	Binary Date	Cumulative Binary	Total	Status
		MW		MW	MW		MW	MW	
53	Rawa Dano	110	2019	3,722	16.5	2019	395	4,116	Shallow drilled, not successful but looks promising
54	Kamojang 6	60	2019	3,782			395	4,176	One well drilled, good success in field overall
55	Mataloko 2	5	2019	3,787			395	4,181	Shallow drilled
56	Way Ratai	55	2020	3,842	8.25	2020	403	4,244	Not yet drilled
57	Gunung Talang	20	2020	3,862			403	4,264	Not yet drilled, volcanic risk, preliminary exploration not promising; figure based on assuming this heading refers to bukit kili
58	Simbolon Samosir	20	2020	3,882			403	4,284	Not yet drilled, preliminary exploration not encouraging
59	Patuha 2 & 3	110	2020	3,992		2020	419	4,411	Part drilled, moderate success; this capacity only achievable if it includes the cibuni sector
60	Tampomas	0	2020	3,992			419	4,411	Not yet drilled, preliminary exploration not encouraging
61	Ungaran 1	55	2020	4,047	8.25	2020	428	4,474	Not yet drilled
62	Ngebel / Wilis	40	2020	4,087	6	2020	434	4,520	Shallow drilled, surface exploration advanced but not encouraging
63	Dieng	55	2020	4,142	8.25	2020	442	4,583	Not yet drilled, assuming this applies to the other fields within the Dieng WKP
64	Ciremai	40	2020	4,182	6	2020	448	4,629	Not yet drilled, only basic exploration done
65	Gunung Endut	40	2020	4,222	6		454	4,675	Not yet drilled
66	Guci	0	2020	4,222			454	4,675	Not yet drilled
67	Ungaran 2	20	2020	4,242			454	4,695	Not yet drilled
68	Umbul Telomoyo	20	2020	4,262			454	4,715	Not yet drilled, only basic exploration done

	Project	Probable Capacity by Date	Possible COD Date	Cumulative	Additional Binary Capacity	Binary Date	Cumulative Binary	Total	Status
		MW		MW	MW		MW	MW	
69	Iyang Argopuro 1	20	2020	4,282			454	4,735	Not yet drilled, only very basic exploration done
70	Tulehu	20	2020	4,302			454	4,755	Not yet drilled, may not be very large
71	Songa Wayaua	5	2020	4,307			454	4,760	Not yet drilled, surface exploration not promising; may only be ok for binary
72	Bora	5	2020	4,312			454	4,765	Not yet drilled
73	Mataloko 3	5	2020	4,317			454	4,770	Shallow drilled
74	Ulumbu 3	5	2020	4,322			454	4,775	Field drilled, but not necessarily this part
75	Kotamobagu 1	40	2020	4,362	6		460	4,821	Drilled, some success
76	Kotamobagu 2	40	2020	4,402	6		466	4,867	Drilled, some success
77	Jailolo 2	5	2020	4,407			466	4,872	Not yet drilled, surface exploration advanced
78	Bonjol	40	2021	4,447	6	2021	472	4,918	Not yet drilled, only basic exploration
79	Danau Ranau	40	2021	4,487	6	2021	478	4,964	Not yet drilled, only basic exploration
80	Kepahiyang	40	2021	4,527	6	2021	484	5,010	Not yet drilled, only basic exploration
81	Bedugul	50	2021	4,577	5	2021	489	5,065	Part drilled, moderate success, but stalled by environmental issues, unlikely to be resolved soon
82	Gunung Lawu	20	2021	4,597			489	5,085	Not yet drilled, may be technical issues
83	Mataloko 4	5	2021	4,602			489	5,090	Shallow drilled
84	Oka Larantuka	3	2021	4,605			489	5,093	Not yet drilled, only very basic exploration
85	Lainea	20	2021	4,625			489	5,113	Not yet drilled, only very basic exploration
86	Sokoria 4	5	2021	4,630			489	5,118	Not yet drilled
87	Tangkuban Perahu 2	0	2022	4,630			489	5,118	Not yet drilled, may not be technically feasible

	Project	Probable Capacity by Date	Possible COD Date	Cumulative	Additional Binary Capacity	Binary Date	Cumulative Binary	Total	Status
		MW		MW	MW		MW	MW	
88	Sipoholon Ria-Ria	0		4,630			489	5,118	Not yet drilled, preliminary exploration not encouraging
89	Cisolok Cisukarame	0		4,630			489	5,118	Drilled, unsuccessful
90	Tangkuban perahu 1	0		4,630			489	5,118	Not yet drilled, preliminary exploration not encouraging
91	Cisolok Cisukarame 2 & 3	0		4,630			489	5,118	Not yet drilled
92	Batu Raden	0		4,630			489	5,118	Not yet drilled, surface exploration advanced but not very encouraging
93	Ijen	0		4,630			489	5,118	Shallow drilled, may be serious issues with acidity
94	Arjuno Welirang	0		4,630			489	5,118	Not yet drilled, may be serious technical issues
95	Iyang Argopuro 2			4,630			489	5,118	Not yet drilled
96	Marana/Masaingi	0		4,630			489	5,118	Shallow drilled, surface exploration not promising
97	Hu'u Daha 2	0		4,630	0		489	5,118	Not yet drilled, surface exploration advanced, but no evidence of large resource
98	Sembalun	0		4,630	0		456	5,118	Not yet drilled

COD = commercial operation date, MW = megawatt, WKP = *wilayah kerja pertambangan* (geothermal work area).

Sources: Estimates of capacity are based on Castlerock Consulting. 2010. *Phase 1 Report: Review and Analysis of Prevailing Geothermal Policies, Regulations and Costs.* Jakarta: Ministry of Energy and Mineral Resources, as modified by more recent information, and as assessed by the technical experts on the study team. The estimates of COD are based on *PT Perusahaan Listrik Negara* (State Electricity Company of Indonesia). 2013. *Rencana Usaha Penuyediaan Tenaga Listrik* (RUPTL) (Electricity Power Supply Business Plan 2012-2021). Jakarta; Castlerock. 2010. Phase 1 Report.

It can be concluded that the targets shown in Table A3.2 now appear achievable provided the Pertamina Geothermal Energy (PGE) commercial partnerships go ahead.

Table A3.2: Revised Targets

	Revised Assessment (MW)	Including Binary Additions (MW)
End 2013	1,345	1,345
2014	1,390	1,489
2016	1,615	1,736
2020	4,400	4,739

MW = megawatt.

Source: Authors' calculations.

Appendix 4

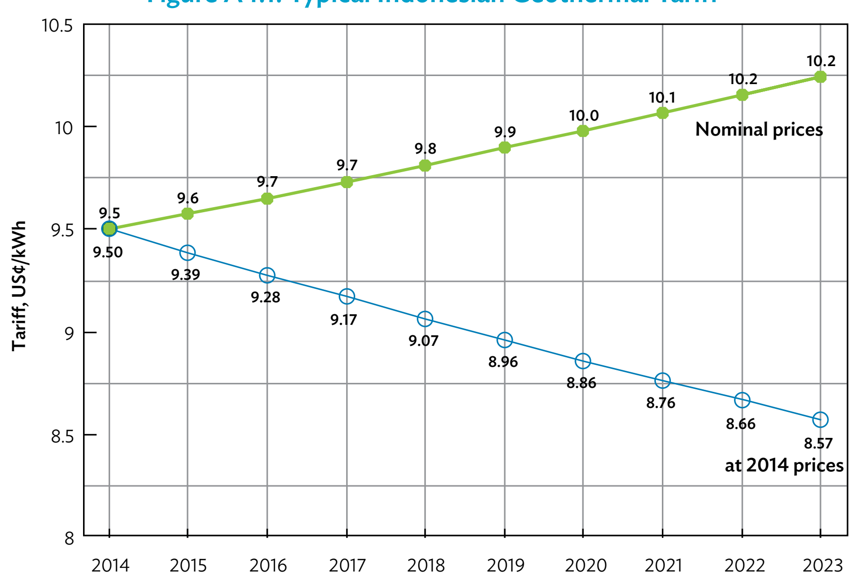
Tariff Structure and Project Finance

Background

At the stakeholder consultation meeting of 19 December 2013, a question was raised about the adequacy of tariffs under project finance. It was noted that the usual criterion of project viability—the financial internal rate of return (FIRR) to investors' equity—was not a reliable indicator of bankability, because the primary measure of cash-flow adequacy in project finance used by lenders is not FIRR, but debt service coverage ratio (DSCR). It is entirely possible that a project meeting a given equity return target is not bankable because of poor DSCRs in the early years of debt service. Simple calculations of FIRR may also be misleading because of other conditions imposed by lenders (such as the funding of debt service and major maintenance escrow accounts before dividends can be paid).

This is related to the problem of calculations of the levelized cost of energy being used to indicate the level of tariff required. Because levelization calculations are typically made over the economic lifetime of a project (typically 25–30 years), the levelized cost of energy is a reliable indicator only if the cost of debt were also spread over the same time horizon. In a project-financed project with a preponderance of locally financed debt, tenors of more than 10 years are seldom achievable. Only with highly concessional finance with generous grace periods and long tenors is the levelized cost of energy a useful indicator. In most cases, debt service obligations are front-loaded.

Figure A4.1: Typical Indonesian Geothermal Tariff



US¢/kWh = cents per kilowatt-hour.
Assumption: PPI index escalates at 2% per annum, applied to 40% of the base price.

Unfortunately, most renewable energy tariffs are back-loaded in consequence of escalation clauses, and many decline over time in real terms if escalation is below the rate of inflation. Recent geothermal tariffs in Indonesia have taken the form of a nonescalating base tariff (typically 60% of the total base price), with the balance escalating according to the United States (US) Producer Price index (PPI). For a hypothetical base price of 9.5 US¢/kWh, the tariff would escalate over time as shown in Figure A4.1. At constant 2014 prices, the tariff decreases over time.

This raises the question of how such a tariff revenue stream matches the developer's actual profile of cash revenue requirement (composed of operation and maintenance [O&M] costs) (including major outlays for make-up wells), debt service obligations, taxes, and equity returns. Our analysis shows that the two match poorly.

Financial Analysis at International Bank of Reconstruction and Development and ADB

The general practice in international financial institution (IFI) appraisal reports is to estimate the financial viability of a project by calculation of a "project financial return" at constant prices, that is independent of the actual financial structure of a project, and that is unrelated to actual cash flows in nominal terms (as would be used by a developer in a project-finance context). This project financial return is then compared to a calculation of the weighted average cost of capital (WACC): the project is declared financially viable if the project return is greater than or equal to the WACC. Table A4.1 shows a typical example of such a project financial return at constant prices.

Table A4.1: Sample Project Financial Returns (at Constant Prices)

			NPV	1	2	3	4	5	6	7	8	9	10	15	20
1	Installed capacity	MW													
2	Capital cost	$/kW													
3	Investment	$ million	282.2	77.6	110.1	73.1	76.8	21.6							
4	O&M	$ million	58.7					8.4	8.4	8.4	10.5	9.4	8.4	8.4	10.5
5	Make-up wells	$ million								18.0		18.0		18.0	0.0
6	Taxes	$ million													
7	Total cost	$ million	390.4	77.6	110.1	73.1	76.8	30.0	8.4	26.4	10.5	27.4	8.4	26.4	10.5
8	Levelized cost	$/kWh	0.068												
9	**Revenue**														
10	Energy	GWh	5711					887.0	887.0	887.0	887.0	887.0	887.0	887.0	887.0
11	Tariff	$/kWh						0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
12	Tariff	$ million		0	0	0.0	0.0	66.5	66.5	66.5	66.5	66.5	66.5	66.5	66.5
13	Financial flows	$ million		–77.6	–110.1	–73.1	–76.8	36.6	58.1	40.1	56.0	39.1	58.1	40.1	56.0
14	FIRR	$ million	11.4%												

FIRR = financial internal rate of return, GWh = gigawatt-hour, MW = megawatt, O&M = operation and maintenance, US¢/kWh = cents per kilowatt-hour.

Note: Actual calculations to 30 years.

Source: World Bank.

The corresponding WACC calculations are shown in Table A4.2.

Table A4.2: Illustrative Weighted Average Cost of Capital Calculation

		Share	Nominal Cost		Real Cost	
1	Equity	0.460	0.1400	6.44%	0.1122	5.16%
2	CTF	0.227	0.0025	0.06%	−0.0220	−0.50%
3	IBRD	0.313	0.0502	1.57%	0.0246	0.77%
4	WACC			8.01%		5.93%
5	Inflation, $				0.025	

CTF = Clean Technology Fund, IBRD = International Bank for Reconstruction and Development, WACC = weighted average cost of capital.
Source: Authors' calculations.

The conclusion which is drawn from this (under the particular assumption of the tariff as shown, 7.5 US¢/kWh) is that the project is financially viable since project financial return equals 11.4%, which is greater than the real (inflation adjusted) WACC, 5.93%.

Such a conclusion is not reliable, for several reasons:

- The implications of the WACC calculation is that equity contributions are *pari passu* with debt. Particularly in the case of geothermal projects, that is not reasonable: the up-front exploration and delineation drilling will be front loaded with equity.
- For the tariff to be shown as constant implies that in nominal terms, the entire tariff escalates at the assumed inflation rate. Since the analysis is presented in US dollars, that would require the entire tariff to escalate at 2% (US PPI)—but in reality, most power purchase agreements (PPAs) negotiated by *PT Perusahaan Listrik Negara* (State Electricity Company) (PLN) allow PPI escalation only on 25%–40% of the base price (as shown in Figure A4.1).
- O&M costs are at constant prices, which implies that both foreign and domestic cost components escalate at the same rate. That seems very unlikely.
- The WACC calculation shows a post-tax equity return for developer of 14%, which is consistent with (no) taxes appearing in Table A4.1. But since the calculation of corporate income tax will be dependent upon the time pattern of interest payments (which will not be constant through the life of the project), it is unclear that the line item for taxes is reliable.
- Nowhere in the (large) spreadsheet model could we find any reference to DSCR. That may not be unreasonable for the project in question, which is 100% financed by international finance institutions (IFIs), but that is not always the case.

The announced rationales for such a procedure are (i) that at the time of the project appraisal report (submitted to boards of IFIs for approval), the details of the financial structure are often not yet finalized, and (ii) that WACC is a valid numeraire for assessing project financial returns.

That may be reasonable in the case of traditional IFI projects involving loans to a large state-owned utility, for which the average cost of debt is indeed composed of a mix of loans of different tenors and interest rates. It is less reasonable in the case of private sector project finance, for which the detail of project cash flows is everything.

Financial Analysis at Nominal Prices

When one uses exactly the same assumptions, but with the actual financial structure used to calculate the cash flows, and at nominal prices (we assume here 2.5% $ inflation, set equal to the US PPI), the calculations show rather different results.

Table A4.3 shows construction period disbursements, assuming that 75% of the capital cost is in dollars, and 25% in Indonesian rupiah (under a 4.5% Indonesian inflation rate assumption). Total construction funding rises from the overnight cost of $359.1 million to $406.2 million when interest during construction and construction period escalation is included. The equity and debt proportions are identical to those shown in Table A4.2, and equity is disbursed *pari passu* with debt.

Table A4.3: Construction Disbursements at Nominal Prices

Year		Share		Sum	1	2	3	4	5
1	**Construction: Uses of Funds**								
2	Overnight costs, constant $		$ million	359.1	77.6	110.1	73.1	76.8	21.6
3	$ share, constant $	0.75	$ million	269.3	58.2	82.5	54.8	57.6	16.2
4	inflation adjusted, nominal $		$ million	287.3	59.7	86.7	59.0	63.6	18.3
5	Rp share, as constant $	0.25	$ million	89.8	19.4	27.5	18.3	19.2	5.4
6	Rp share, at Rp inflation		$ million	101.6	20.3	30.2	21.0	23.2	6.8
7	VAT on Rp share	0	$ million	0.0	0.0	0.0	0.0		0.0
8	Total construction cost		$ million	388.8	79.9	116.9	80.0	86.8	25.1
9	*IDC/service charge*								
10	CTF	0.0	$ million	0.7	0.0	0.1	0.2	0.2	0.2
11	IBRD	0.1	$ million	16.6	0.6	2.0	3.5	4.8	5.7
12	Total uses of funds		$ million	406.2	80.5	119.0	83.7	91.8	31.1
13	**Construction: Sources of Funds**								
14	Equity	0.46	$ million	186.8	37.0	54.8	38.5	42.2	14.3
15	Balance for debt		$ million	219.3	43.5	64.3	45.2	49.6	16.8
16	Debt								
17	CTF	0.42	$ million	101.5	20.1	29.8	20.9	23.0	7.8
18	IBRD	0.58	$ million	117.8	23.4	34.5	24.3	26.6	9.0
19	Total sources of funds		$ million	406.2	80.5	119.0	83.7	91.8	31.1

CTF = Clean Technology Fund, IBRD =International Bank for Reconstruction and Development, IDC = interest during construction, Rp = Indonesian rupiah, VAT = value added tax.

Source: World Bank.

Table A4.4 shows the developer cash flows. Other assumptions here are:

- that the tariff escalates according to the PLN PPA formula, with 60% of the base price escalating at the US PPI;
- that the foreign exchange share of O&M is 25%, the Rp share is 75%;
- that make-up wells have the same foreign exchange share as the first investment cost; and
- that the corporate tax rate is 34%.

Table A4.4: Developer Cash Flows, at Base Tariff of 7.5 US¢/kWh and Equity Pari Passu

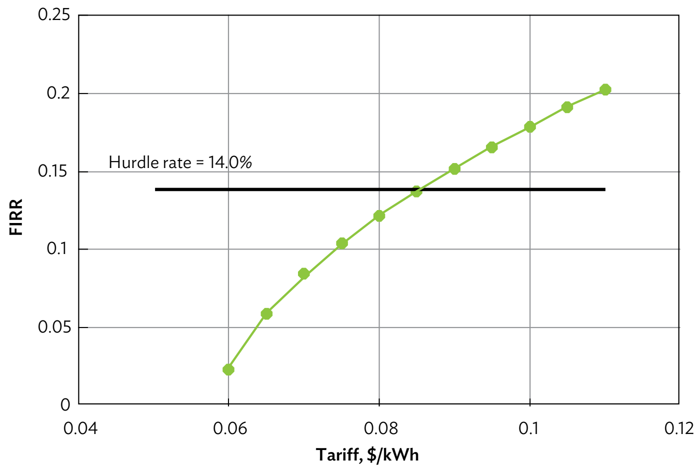
	Year	Shares		NPV	1	2	3	4	5	6	7	10	15
1	**O&M Costs**												
2	O&M ($ share)	0.25	$ million						2.10	2.10	2.10	2.10	2.10
3	O&M (Rp share)	0.75	$ million						6.30	6.30	6.30	6.30	6.30
4	Make-up wells ($ million)	0.75	$ million						0.00	0.00	13.50	0.00	13.50
5	Make-up wells (Rp)	0.25	$ million						0.00	0.00	4.50	0.00	4.50
6	**Cash Disbursements**												
7	Equity		$ million		37.1	54.8	38.6	42.4	14.5				
8	***O&M Costs***												
9	O&M ($ share)		$ million						2.38	2.44	2.50	2.69	3.04
10	O&M (Rp share)		$ million						8.00	8.40	8.82	10.21	13.03
11	Make-up wells ($)		$ million						0.00	0.00	16.05	0.00	19.55
12	Make-up wells (Rp)		$ million						0.00	0.00	6.30	0.00	9.31
13	***Principal Repayments***												
14	CTF		$ million		0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	5.4
15	IBRD		$ million						0.0	0.0	6.4	6.4	6.4
16	Interest		$ million										
17	CTF		$ million						0.2	0.2	0.2	0.2	0.1
18	IBRD		$ million						6.2	6.4	6.2	5.3	3.7
19	Income tax		$ million	34.0	0.0	0.0	0.0	0.0	9.1	9.1	2.5	9.7	1.7
20	Total cash out		$ million	371.5	37.1	54.8	38.6	42.4	40.4	26.6	49.0	39.9	62.3
21	**Revenue**												
22	Energy		GWh	5382					887.0	887.0	887.0	887.0	887.0
23	Tariff		$/kWh						0.075	0.076	0.077	0.079	0.083
24	Revenue		$ million		0.0	0.0	0.0	0.0	66.5	67.2	67.9	70.0	74.0
25	**Total Cash Flows**		**$ million**		–37.1	–54.8	–38.6	–42.4	26.2	40.6	18.9	30.2	11.7
26	Post-tax IRR, nominal		[ ]	10.4%									
27	Deflated Cash Flows		$ million		–36.2	–52.2	–35.9	–38.4	23.1	35.0	15.9	23.6	8.1
28	Real, post tax		[ ]	7.7%									
29	DSCR				37.1	54.8	38.6	42.4	14.5				

$/ kWh = dollars per kilowatt-hour, CTF = Clean Technology Fund, DSCR = debt service coverage ratio, GWh = gigawatt-hour, IBRD = International Bank for Reconstruction and Development, IRR = internal rate of return, Rp = Indonesian rupiah, O&M = operation and maintenance.

Source: Authors' calculations.

At the stated base tariff of 7.5 US¢/kWh, the post-tax, nominal FIRR is 10.4%, significantly below the 14% return assumed for developer in the project financial analysis. To achieve the stated equity target requires a base year tariff of 8.6 US¢/kWh, not 7.5 US¢/kWh.

Figure A4.2: Equity Return versus Tariff



$/kWh = dollars per kilowatt-hour, FIRR = financial internal rate of return.

Source: Authors' calculations.

The debt/equity ratio and equity timing is critical. The above calculations assume a developer equity share of 46%, and for simplicity it is generally assumed in project financial analysis that equity contributions are *pari passu* with debt. For geothermal projects that is unlikely. Table A4.5 shows the same calculation, but for equity up-front (i.e., disbursed ahead of debt).

Table A4.5: Construction Period Disbursements, Equity Up Front

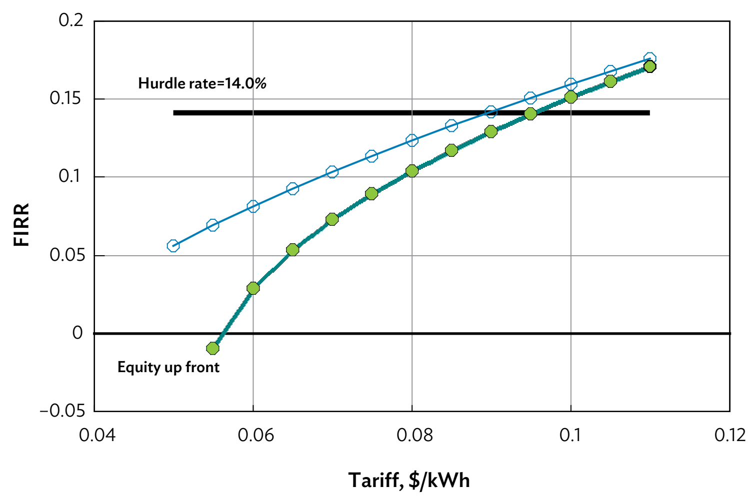
		Share		Sum	1	2	3	4	5
1	**Construction: Uses of Funds**								
2	Overnight costs, constant $		$ million	359.1	77.6	110.1	73.1	76.8	21.6
3	$ share, constant $	0.75	$ million	269.3	58.2	82.5	54.8	57.6	16.2
4	inflation adjusted, nominal $		$ million	287.3	59.7	86.7	59.0	63.6	18.3
5	Rp share, as constant $	0.25	$ million	89.8	19.4	27.5	18.3	19.2	5.4
6	Rp share, Rp inflation		$ million	101.6	20.3	30.2	21.0	23.2	6.8
7	VAT on Rp share	0	$ million	0.0	0.0	0.0	0.0		0.0
8	Total construction cost		$ million	388.8	79.9	116.9	80.0	86.8	25.1
9	***IDC/Service Charge***								
10	CTF	0.0	$ million	0.4	0.0	0.0	0.1	0.1	0.2
11	IBRD	0.1	$ million	11.7	0.0	0.2	1.6	4.1	5.8
12	Total uses of funds		$ million	400.9	79.9	117.1	81.7	91.1	31.2
13	**Construction: Sources of Funds**								
14	Equity	0.46	$ million	184.4	79.9	104.5	0.0	0.0	0.0
15	Balance for debt		$ million	216.5	0.0	12.6	81.7	91.1	31.2
16	***Debt***								
17	CTF	0.42	$ million	90.9	0.0	5.3	34.3	38.2	13.1
18	IBRD	0.58	$ million	125.6	0.0	7.3	47.4	52.8	18.1
19	Total sources of funds		$ million	400.9	79.9	117.1	81.7	91.1	31.2

CTF = Clean Technology Fund, IBRD = International Bank for Reconstruction and Development, IDC = interest during construction, Rp = Indonesian rupiah, VAT = value added tax.

Source: Authors' calculations.

When equity is up front, several consequences arise. First, is that interest during construction decreases, so the total completed financial cost decreases slightly from $406.2 million to $400.9 million. Second, at the old base tariff of 7.5 US¢/kWh, the FIRR falls from 10.4% to 9.4%. At the 14% FIRR target, the required tariff is 9.2 US¢/kWh. But when equity is provided up front, at least in the private sector the aggregate FIRR target will also increase, so the gap between the achievable FIRR and the target really increases by more than 1%. Figure A4.3 shows the differences over a range of tariffs.

Figure A4.3: Impact of Equity Disbursement Timing

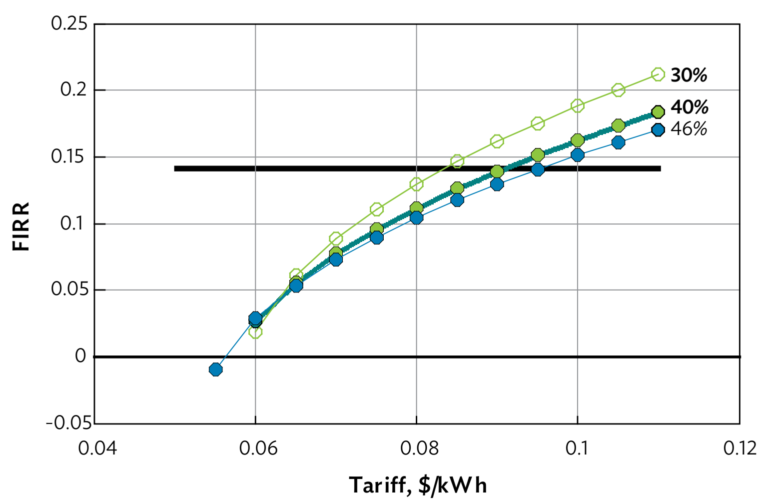


$/kWh = dollars per kilowatt-hour, FIRR = financial internal rate of return.

Source: Authors' calculations.

Figure A4.4 illustrates the impact of the debt to equity ratio. The lower the equity share, the higher lies the curve—which means that for a given FIRR, the higher the equity share, the lower the required tariff.

Figure A4.4: Impact of Debt/Equity Ratio (Equity Up Front)



$/ kWh = dollars per kilowatt-hour, FIRR = financial internal rate of return.

Source: Authors' calculations.

These results are summarized in Table A4.6.

Table A4.6: Sensitivity of Tariffs to Financial Structure (Typical Project Financed with International Finance Institution Concessionary Debt)

Equity Share	Equity Contributed	Required Tariff for 14% Equity Return US¢/kWh
46%	Pari Passu	8.6
46%	Up front	9.2
40%	Up front	8.7
30%	Up front	8.0

¢/kWh = cents per kilowatt-hour.
Source: Authors' calculations.

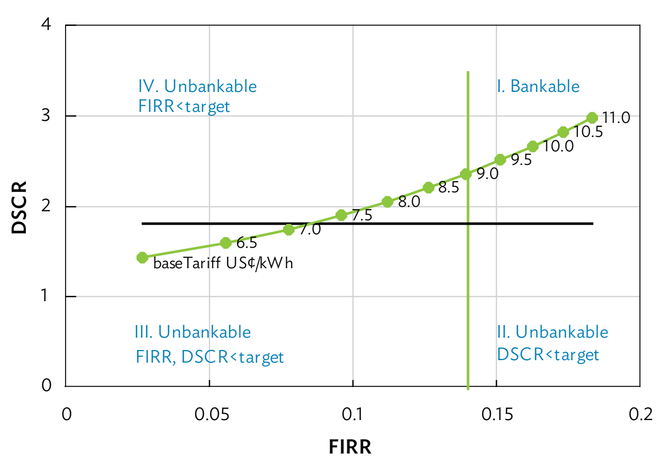
Bankable Projects

A bankable project in project finance is one that meets both the objective of investors (for example as the desired return to equity) and the objective of lenders—which translates to adequacy of cash flows to meet debt service obligations, most frequently captures by the debt service coverage ratio (DSCR). Both of these targets will vary from project to project depending on the relative perceptions of project risk.

In fact, once a geothermal project reaches financial closure, much of the project risk has been reduced. Lenders and equity holders in other types of renewable energy project face significant resource risk after project completion—annual variations in hydrology in small hydropower projects, or annual variations in average wind speeds can vary by +30% over long term averages as established in feasibility studies—which may have significant impact on cash flows. One of the major advantages of a geothermal project is that once constructed, annual plant factors will likely be fairly constant in the 90%–95% range (always assuming competent operation and maintenance).

Figure A4.5 illustrates this idea. Bankable projects are to be found in quadrant I, where the quadrants are defined by the minimum requirements for DSCR (here shown as 1.8) and FIRR (here shown as

Figure A4.5: Bankable Project Definition



US¢/kWh = cents per kilowatt-hour, DSCR = debt service coverage ratio, FIRR = financial internal rate of return.
Assumptions: 40% equity, equity up front.
Source: Authors' calculations.

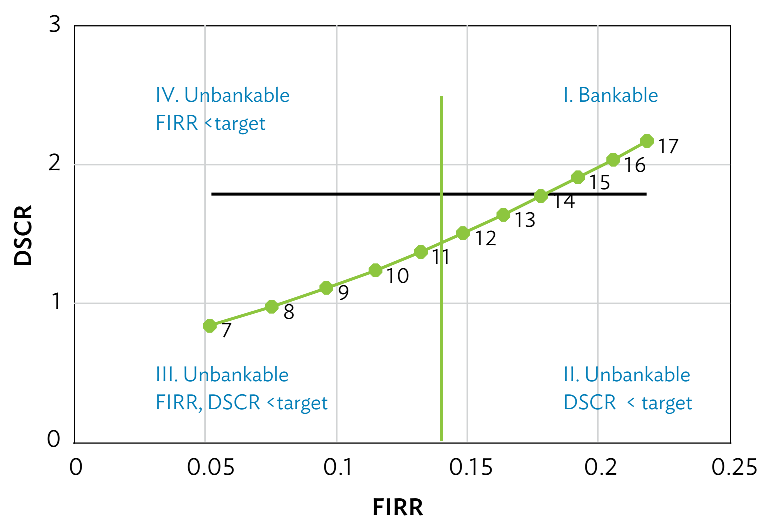
14%). In all of the other quadrants, either or both requirements are not met. The curve in Figure A4.5 shows the relationship between FIRR and DSCR at each level of base tariff.

We see that above a tariff of 7.2 US¢/kWh, projects meet the DSCR requirement; but at that tariff, the FIRR is an unsatisfactory 8%. Only at a tariff of about 9.1 US¢/kWh is the FIRR target achieved, and the curve enters bankable territory. In this case it is clear that the FIRR requirement is indeed binding, rather than DSCR.

This conclusion changes with nonconcessionary commercial finance. In Figure A4.6 we show the result for the same project, again with 40% equity up front, but now financed at 7% over loan tenors of 8 years with just 2 years grace during construction of the power plant.

Under these conditions we see that the 14% hurdle rate for FIRR is reached at a base tariff of 11.5 US¢/kWh, but at this level, the DSCR of 1.44 is still below the previous DSCR target of 1.8. To reach this threshold requires a tariff of 14.2 US¢/kWh, at which point the FIRR is 18%.

Figure A4.6: Non-Concessionary Finance



DSCR = debt service coverage ratio, FIRR = financial internal rate of return.
Assumptions: 40% equity, equity up front.
Source: Authors' calculations.

Conclusions

The analysis permits a range of important conclusions relevant to the geothermal sector in Indonesia, and to the issuance of a new tariff:

- Calculations of project financial returns following conventional IFI practice are often unreliable.
- Actual financial returns to developer's equity are critically dependent on the proposed financial structure. Financial returns should be based on estimated cash flows and cash revenue requirements, calculated at nominal prices. The resulting FIRR may be quite different to "project" financial returns.

- Simple calculations of WACC for geothermal projects are unreliable. Not only are they independent of loan tenors, they also assume equity pari passu with debt, unrealistic for geothermal projects.
- Tariffs issued on the basis of production costs will be highly dependent on financial structure and financing terms. FIRR may be much more sensitive to the financial structure than to individual technical assumptions. We have not seen the financial model being used by MEMR, but it seems that the tariffs are calculated on the basis of achieving a "16.5% project IRR." The details of the MEMR production cost tariff model should be examined (just as the details of the Sinclair Knight Merz Limited model require review).
- Projects financed with concessional IFI funding, that meet equity investor FIRR targets, will also have healthy DSCRs: for such projects, meeting DSCR standards are of little concern. Because of long loan tenors, and low interest rates (particularly on CTF funds), revenue requirements to meet target international rate of return are not front-loaded, so the current PPA escalation and/or indexation approach is not problematic. Generous grace periods and low first year debt service payments result in good cash flows even in the early years. Phrased differently, in concessionary financed projects, equity IRR, not DSCRs (to the extent that they apply at all) are likely to be the binding condition for bankability.

Front-Loaded Tariffs in Other Countries

The best example of front-loaded tariffs for capital intensive renewable energy projects is Sri Lanka. While it has no geothermal resources, its FITs for wind and small hydro provide for two options:

- a three-tier fixed payment for recovery of investment and equity return, plus an escalable component for O&M; or,
- a fixed levelized payment, non-escalable (which then declines in real terms).

The idea of a three-tier tariff for investment cost recovery is precisely because in Sri Lanka, most small hydropower and wind power projects are financed locally, with loans of short tenor. The three-tier tariff rates are as follows:

Table A4.7: Three-Tier Tariff Rates in Sri Lanka

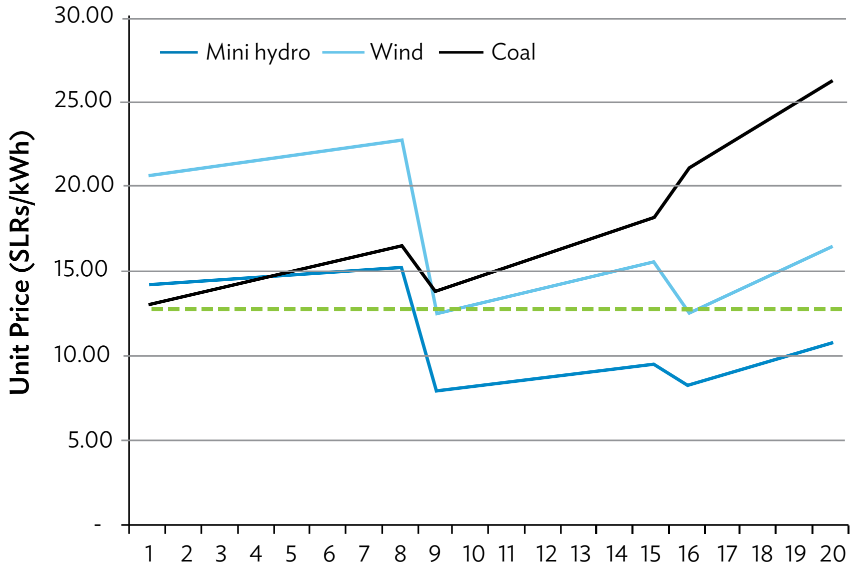
Technology/Source	Non-escalable			Escalable	Escalable
	Year 1–8	Year 9–15	Year 16+	Base O&M (year 1–20)	Base Fuel (year 1–20)
Mini-hydro	12.64	5.16	None	1.61	None
Mini-hydro-local	12.92	5.28	None	1.65	None
Wind	17.78	7.26	None	3.03	None
Wind-local	18.28	7.47	None	3.11	None
Biomass (1–15 years)	7.58	3.10	None	1.29	9.10
Biomass 16 year onwards	7.58	3.10	None	1.61	9.10
Agro & Indus (1–15 years)	7.58	3.10	None	1.29	4.55
Agro and Indus 16 year onwards	7.58	3.10	None	1.61	4.55
Municipal Waste	15.16	6.19	None	4.51	1.75
Waste Heat	7.13	2.65	None	0.43	None
Escalation per year	None	None	None	7.64%	5.09%

Agro = agriculture, hydro = hydropower, Indus = industry, O&M = operation and maintenance.

Source: Public Utilities Commission of Sri Lanka.

So, for example, for investment recovery, a wind project gets 17.78 SLRs/kWh (13.5 US¢/kWh) in years 1–8, 7.26 SLRs/kWh (5.5 US¢/kWh) in years 9–15, and nothing from year 16 onward. The PPA stipulates that the energy deliverable in years 9–15 must be at least the same as that delivered in years 1–8. The resulting time patterns are illustrated in Figure A4.7.

Figure A4.7: Three-Tier Front-Loaded Tariffs in Sri Lanka



hydro = hydropower plant, SLRs/kWh = Sri Lanka rupees per kilowatt-hour.

Source: Authors' calculations based on data from the Public Utilities Commission of Sri Lanka.

Appendix 5

Possible Technology Paths to Faster Development

Use of Ancillary Plant

By far the largest geothermal generation capacity in Indonesia uses condensing steam turbines with evaporative (wet) cooling towers. This is similar to the situation in most of the rest of the geothermal industry worldwide, but there are other mature, well proven technologies that offer some advantages particularly in terms of mobilization time and that have not been taken up in Indonesia to any significant degree as yet. They may well present an opportunity to accelerate the Indonesian program.

Stand-Alone Back Pressure Plants

A back pressure turbine exhausts usually to atmosphere (or in some cases to another second-stage turbine), unlike a condensing turbine which exhausts to a subatmospheric condenser. These two turbines are diagrammed in Figure A5.2 and Figure A5.4, respectively. In the geothermal energy context, back pressure plants (BPPs) differ in the following ways from the more common condensing plants:

Advantages:

- Simple and robust.
- Do not require a cooling circuit, so smaller footprint.
- Available in small sizes and widely available.
- Much shorter manufacture and commissioning time: typically 1 year or less compared to 2 to 3 for a 55 MW condensing plant.
- Much cheaper: roughly half the capital expenditure/MW delivered.
- If running on a liquid dominated resource (the most common), still require reinjection wells for separated water, but do not require condensate injection wells.
- Because of their small size and simplicity, can easily be remobilized from one project to another.

Disadvantages:

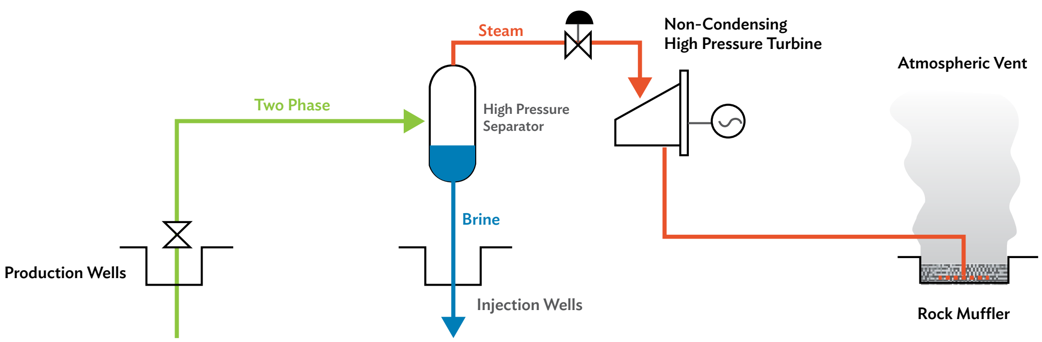
- Relatively inefficient, as they require about twice as much steam per MW as a condensing plant. This impacts the number of production wells and can raise concerns about the efficiency of resource use and sustainability if used long term.
- Probably require more frequent maintenance than larger condensing units, in part because they tend to be connected to relatively unsophisticated steam gathering systems (e.g., no steam scrubbers), though because of their simplicity this should not be expensive.

- Potentially greater environmental impact (noise, exhaust condensate spray), but not great if properly designed and operated as has for example been well demonstrated in Mexico.
- If distributed around a field, add complexity to the electrical interconnection.

Mode of Deployment

There has been only one such small (1.5 MW) unit deployed in Indonesia in recent years, at Sibayak. That was a relatively unsophisticated installation, on a less than ideal resource, and should not be regarded as typical. PLN has also run a BPP at Ulumbu (2 x 2.5 MW). The typical set-up of a back-pressure steam turbine is shown in Figure A5.1. Elsewhere in the world such units in the 1 MW–5 MW range have been used either on individual wells (well head generators) or with small numbers of wells interconnected to multiple back pressure units. This has been particularly commonly used in Mexico, but has also been successfully done in several other countries including El Salvador, Nicaragua (Figure A5.2), Papua New Guinea, and the Philippines.

Figure A5.1: Back Pressure Steam Turbine—Stand Alone Operation

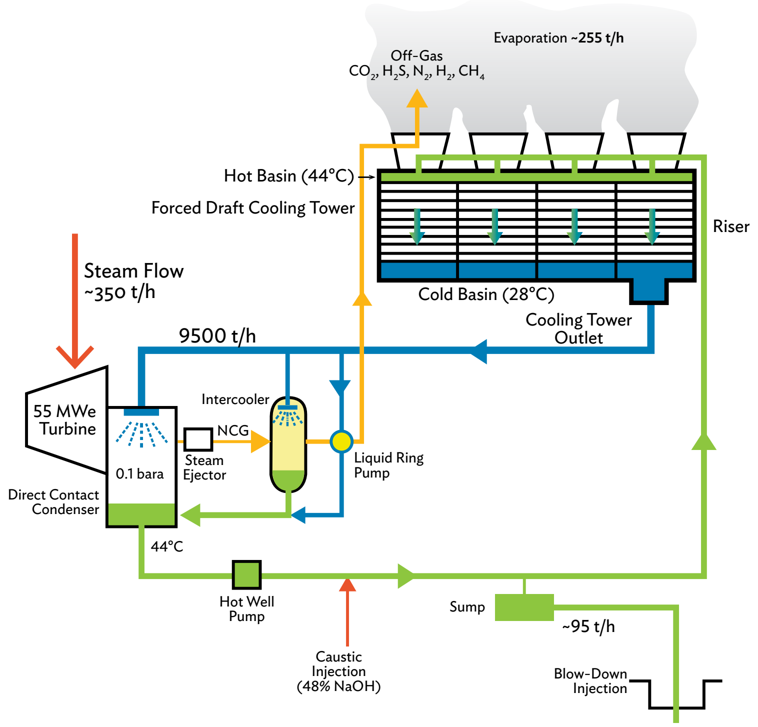


Source: J. Lawless. 2008. Cost Reduction Through Improved Geothermal Well Targeting. Paper for the Western Pacific Regional Branch of the International Geothermal Association/INAGA Joint Technical Seminar. Nusa Dua, Bali. 26-28 April.

Figure A5.2: San Jacinto Project, Nicaragua: 2 x 5 Megawatt Back Pressure Plant

Source: Author's photograph.

Figure A5.3: Schematic of Condensing Steam Turbine Plant



Bara = absolute pressure, C = Celsius, CH_4 = methane, CO_2 = carbon dioxide, H_2 = dihydrogen, H_2S = hydrogen sulfide, MWe = megawatt electric, N_2 = nitrogen, NaOH = sodium hydroxide, t/h = ton per hour.

Source: J. Lawless. 2008. Cost Reduction Through Improved Geothermal Well Targeting. Paper for the Western Pacific Regional Branch of the International Geothermal Association/INAGA Joint Technical Seminar. Nusa Dua, Bali. 26–28 April.

Figure A5.4: McLachlan Plant, Wairakei, New Zealand: 55-Megawatt Condensing Steam

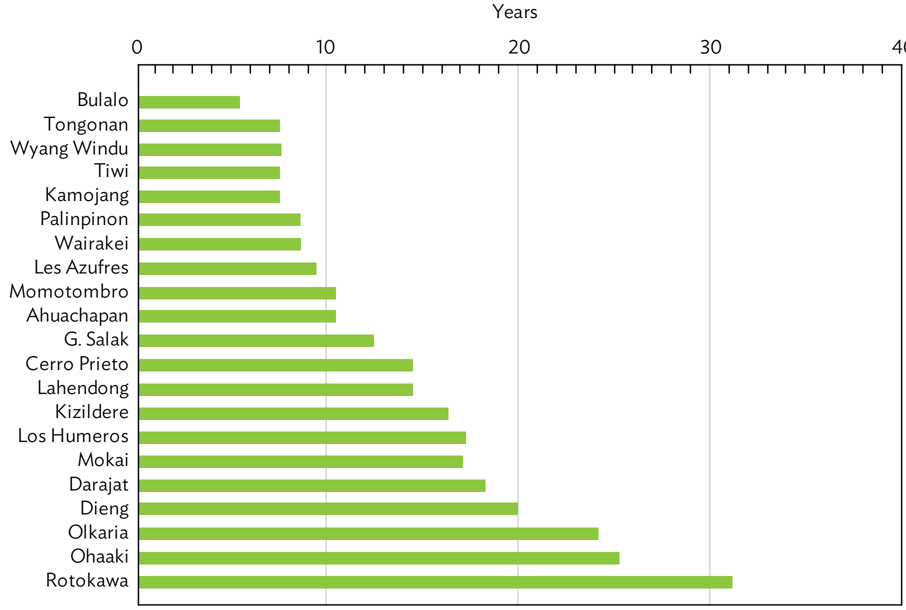
Note: This plant uses a second-hand Fuji turbine. Note the evaporative cooling towers.

Source: Author's photograph.

In very remote locations, BPPs may be operated on a semi-permanent basis, but more commonly they are used for a few years before being replaced by a larger condensing and/or binary plants. A schematic of a condensing steam turbine plant is shown in Figure A5.3.

The huge advantage of such a scheme is the early availability of generation and revenue. Even the successful early exploration wells can be put to use within 12 months of being drilled, which could otherwise sit unused for many years (Figure A5.5). More significantly, there are projects in Indonesia such as Karaha where for various reasons as many as half the production wells for a large scheme have been drilled and left closed for a decade or more.

Figure A5.5: Time from First Exploration Well to Commercial Operation Date



Source: Authors' calculations.

There are also other less tangible advantages. Early operation of a BPP gives an early test of the reservoir in a way that is far more comprehensive and reliable than individual short-term well tests. This adds confidence to the estimation of resource capacity, provides information on likely well run-down rates, fluid chemistry, and permits closer optimization of the design parameters such as separation pressure and turbine inlet pressure for the larger ultimate scheme. Perhaps, just as significantly, it provides investors with additional confidence in the feasibility of the project.

The question then has to be asked, why has there not been greater use of this development pathway in Indonesia and what is hindering its use in the future? Several possibilities arise:

- The power price is unlikely to be a disincentive, since the cost per megawatt of such schemes must be less than for condensing plants, especially if the wells are regarded as "free" for this purpose. Nevertheless, the financial viability needs to be demonstrated.
- Current power purchase agreements (PPAs) do not appear to allow for early small-scale generation. Some developers acknowledged that this could be an obstacle. However, one pointed out that activating the PPA early had the advantage of initiating the escalation clauses—though it would mean it also terminated earlier than otherwise.
- The business model with the developer providing steam and a different party owning the power plant does not allow the developer to also undertake early generation, whereas it is the developer who has expended the early investment and has the incentive to do so. If PLN is to own the eventual larger plant there, but has invested nothing in drilling, there is little incentive for PLN to undertake early generation.
- The developers are reluctant to either install temporary pipelines (and in most cases separators) to connect the wells to the plant or to pre-invest in part of the permanent steam above ground system (SAGS), especially at a time when not all of the wells have been drilled so the permanent SAGS cannot be fully designed. The same applies to the electrical switchyard. Neither of these should be insurmountable.

- Depending on the location PLN may be reluctant to install a transmission line, including land acquisition, for the sake of a small amount of generation. There are ways around that: for example, at the San Jacinto project in Nicaragua a 2 x 5 MW BPP was installed 3 years before the full 2 x 36 MW condensing plant. The transmission voltage and towers were sized for the full-sized plant, which would run in a double circuit mode, but for the smaller BPP only a single circuit was initially installed. Because of the small size of the units, there should not be issues with grid control.
- The environmental impact assessments and environmental permits may have to be modified.
- The Government of Indonesia may be reluctant to permit relatively inefficient use of the resource (though we have no evidence that this is the case). Where this issue has arisen in other countries, one approach has been to limit the time that the BPP can operate for on any particular project.

All of these issues may in the part simply have made the concept “too hard” for the developers and PLN who were focused on the larger developments needed to recoup their significant investments in exploration and development. However, in the current context, with the development program falling well behind schedule, it may be worth re-examining what can be done to facilitate this approach in the national good.

Bottoming Binary Plants

A binary cycle plant uses heat exchangers and a secondary working fluid of low boiling point rather than passing geothermal steam directly through a turbine. In the geothermal context, they differ in the following ways from condensing steam plants:

Advantages:

- Usually (though not necessarily) are air-cooled rather than using evaporative cooling towers, and so conserve water usage (whether of geothermal or other origin). This can be an important issue for arid areas, or where minimizing pressure drawdown in the geothermal reservoir is important, but so far neither of these has been perceived to be a major factor in Indonesia.
- Available in small sizes (<1 MW to 15 MW) and available from several manufacturers in modular form. This also means that the economies of scale for binary plant are less significant than for a condensing steam plant.
- Much shorter manufacture and commissioning time: typically 1 to 1.5 years compared with 2 to 3 years for a 55 MW condensing plant.
- Because of their small size and modular construction simplicity, can be remobilized from one project to another.
- Most significantly, can make use of lower temperature geothermal fluid than condensing steam plants. They can, however, also make use of moderately high temperature resources.
- Can cope with higher noncondensable gas contents than condensing steam plant.
- Have somewhat reduced environmental impact as all liquid is reinjected, though there are a few additional environmental issues that have to be considered, most notably the storage and use of relatively large amounts of hydrocarbon working fluids. In practice, unless maintaining reservoir pressures is of great concern because of effects such as subsidence, the differences are small.

Disadvantages:

- Higher cost per MW than a condensing turbine by a factor of about three.
- If used in a bottoming mode (which is what is proposed here), the reservoir fluid is cooled before reinjection to about 100°C rather than the 160°C, which would be more common for condensing plants. This raises the potential for mineral scaling particularly of silica in the reinjection system. Modern practice has however developed several means of dealing with this, including recombining separated water (which can have chemical advantages as well as providing dilution), and condensate and chemical dosing, which has proven to be effective when properly designed and operated, at moderate cost.
- The fact that the reinjection temperature is lower can potentially have adverse reservoir impacts if not properly managed. However, if done properly it can also lead to greater overall energy recovery.
- In a high-enthalpy resource that is intensively exploited, particularly without full reinjection, the steam fraction produced by the wells can rise with time. This is advantageous from the point of view of a condensing plant as it increases the steam flow and reduces the reinjection load, but it can lead to an associated binary plant being under supplied with liquid. In the worst case, part of the binary plant may have to be decommissioned, but since it is modular and can be redeployed elsewhere it does not have to be a fatal constraint, especially for an operator with a large portfolio. Alternatively, the modular nature allows a more conservative approach to be taken and the binary units installed progressively over time as the reservoir response to exploitation becomes better known.

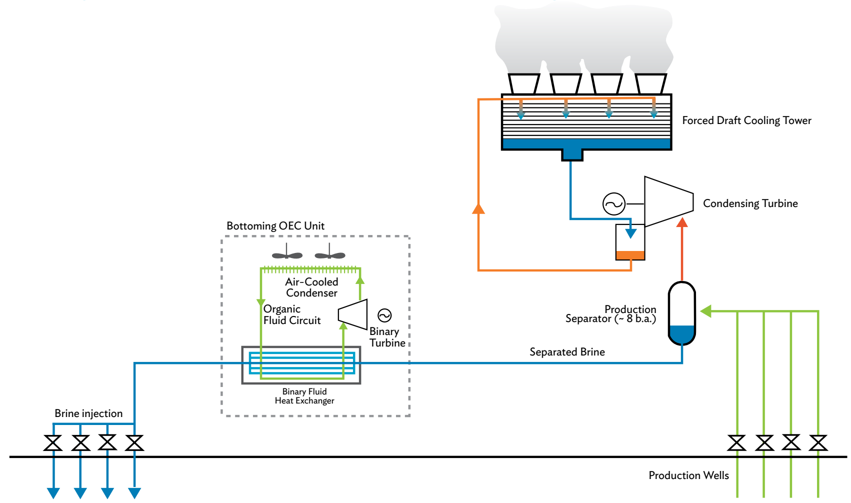
Mode of Deployment

One binary plant has been deployed in Indonesia at Lahendong, and that is perhaps better regarded as a prototype rather than as a typical modern commercial unit. Elsewhere in the world binary plants have been deployed either as single units or in combinations up to 155 MW. They are used in three very different ways, only one of which is proposed in the present context (Figure A5.6):

1. **Mode 1:** as stand-alone units or combinations of units operating on the whole of the fluid produced by the wells:
   a. **Mode 1a:** to take advantage of their ability to generate from lower temperature resources, or,
   b. **Mode 1b:** to minimize reservoir impact because of the greater reinjection fraction, or,
   c. **Mode 1c:** to deal with difficult fluids such as those with a high gas content.
2. **Mode 2:** in effect, to replace the condensers on a condensing steam plant, utilizing a combination of a back pressure steam turbine and a binary unit used as a steam condenser.
3. **Mode 3:** in combination with a steam turbine, to extract extra energy from the separated water. Thus in a very real and defensible sense, they add to the extractable capacity of a given resource.

It is only the third mode that is relevant in the present context. Use on low temperature resources (mode 1a) is very important in certain countries but the probable power prices in Indonesia would not support the use of such resources except in the special case of very remote locations with few alternative generation options. Such projects are important in terms of social impact but are likely to be small in terms of additional MW in the national portfolio. The need to reinject a greater fraction, as used in mode 1b, is not currently perceived to be an issue in Indonesia. Mode 1c or mode 2 could be used at certain locations, but that would be an engineering and cost design decision on a case by case basis and in the present context would replace a condensing plant rather than adding to the national generation total.

Figure A5.6: Bottom Binary Plant Operating on Separated Water



Source: J. Lawless. 2008. Cost Reduction Through Improved Geothermal Well Targeting. Paper for the Western Pacific Regional Branch of the International Geothermal Association/INAGA Joint Technical Seminar. Nusa Dua, Bali. 26-28 April.

Figure A5.7: Bottoming 17-Megawatt Binary Plant (Foreground) at Wairakei, New Zealand

Note: Notice the bank of air-cooling fans. The original 50-year old condensing steam plant is in the background. It lacks cooling towers, because it has an unusual cooling system using direct contact river water. That has no particular relevance in terms of the retrofitted binary plant.

Source: Author's photograph.

The significant advantage of the third mode of operation is that it can rapidly (within as little as 1 year) produce 15%–20% of additional electricity without requiring any additional wells, since the separated fluid is already available on the surface. It is therefore practically free of resource risk, provided the issues of scaling and reservoir management can be dealt with. Examples in many fields worldwide demonstrate that such issues are manageable. Additional environmental issues are likewise small. Significantly, so-called "bottoming" binary units can be retrofitted to existing condensing steam plants with only very minor engineering modifications, which would not require the condensing plants to be out of operation for a long period.

As with BPPs, the question is why has there not been greater use of this development pathway in Indonesia, and what is hindering its use in the future?

Some possibilities are:

- The higher capital cost per MW compared to a condensing plant, coupled with historically low tariffs. However, tariffs have or will rise, and more significantly drilling costs (especially when the averaged effect of unsuccessful wells is taken into account) have risen faster than power plant costs.[2] Therefore, the cost differential between a bottoming binary plant (excluding wells) and that of a whole scheme (including wells) based on a condensing steam plant is much less than it used to be. Nevertheless, the financial viability (taking proper account of the shorter lead time) needs to be demonstrated.[3]
- PPAs are not set up to allow for additional small-scale generation.
- PLN may be reluctant to install additional transmission capacity. Because of the small size of the units, there should not be issues with grid control.
- The environmental impact assessments and environmental permits may have to be modified.
- The developers may have historically been concerned about silica deposition because of the greater fluid cooling before reinjection. This is a real issue, but in recent years ways of dealing with it have been proven.
- An unusually higher proportion of the projects developed so far in Indonesia are on dry or nearly dry steam resources. Darajat and Kamojang are dry steam, Wayang Windu and part of Dieng are almost dry, to the point where bottoming binary units would be of limited applicability. But the proportion of liquid resources where binary units are applicable will rise with time.
- Developers are concerned about adverse reservoir impacts,[4] but as noted above there are many examples worldwide where such have been successfully avoided.

As with the BPP concept, with the development program falling well behind schedule, it may be worth re-examining what can be done to facilitate this approach especially with regard to retrofitting to existing plants.

Potential Impact

An estimate is made of additional generation possible by retrofitting binary units to existing condensing steam plants or including them in the design of future plants is provided in Appendix 2. The actual

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2 Because they are very efficient at drilling, this advantage is less for Chevron than for the other operators. It said that it had been, and was now, evaluating binary options but in its projects the best financial return was in adding more condensing units. That does not mean that the financial return for binaries was nil, and in the future, as it has probably more or less installed the full capacity of condensing units that the existing wet resource at Salak may support, it may be more willing to consider this option.

3 When AECOM/Sinclair Knight Merz Limited prepared financial models in 2010 for Pertamina Geothermal Energy (PGE) as part of the feasibility studies for Lumut Balai, Ulubelu, and Tompaso, they included binary options and concluded they were financially inferior to a purely condensing plant. But that was within the scope of a fixed PPA capacity (i.e., the binary plants were to replace part of the condensing plant, not to be incremental to it), and in the event the differences in net present value (NPV) were small.

4 This is the case for PGE at Ulubelu where there has already been some cooling of certain production wells by reinjections. The issue is about to be analyzed using reservoir modeling, and should be manageable provided PGE stops injecting close to a major fault which conducts the reinjected fluid back to the production wells.

amount of additional generation possible will depend on the fluid enthalpies and separation pressures in each case, but for the present purpose a default and conservative increment of 15% of the output of the condensing plant operating on "wet" resources is assumed. That figure is conservative: in some projects it is going to be as high as 20%. Kamojang, Patuha, and Darajat are excluded as they use dry steam. Because of the small separated water fraction at Wayang Windu, a smaller estimate of possible binary capacity is given than for the other fields. It is assumed that a retrofitted binary plant could be installed within 12 months for existing plants, and simultaneously with commissioning of new condensing plants. Some additional delays in the program are anticipated so the estimates are conservative.

Looking only at Java and Sumatra, it can be seen from the estimates in Section 2, Table 2.3 that there is potential for about 125 MW of binary to be added "immediately" (i.e., within 12 months), possibly plus another 5 MW at Wayang Windu, though it is uncertain whether that small increment there would be considered worth pursuing. The possible additional total by the end of 2020 is in excess of 400 MW.

Opportunities for Technical Improvements in Planned Developments Using Condensing Steam Plant

Use of Larger Units

For condensing steam turbine plants, the type planned for all developments in the near future in Indonesia, there are significant economies of scale both in terms of the size of the schemes overall and the size of the individual units used. It can be assumed that the overall size of the planned developments has been thought through in the context of prudent incremental development, resource capacity,[5] grid and market constraints, and availability of finance[6]—though those factors could well change in the course of development.

However, most of the developments and in particular those planned by Pertamina Geothermal Energy (PGE) are based around unit sizes of 55 MW. In some cases there are good reasons, as given in the previous paragraph, why that should be so. But in other cases such as Ulubelu 3 and 4, where two 55 MW units are to be installed on the same resource simultaneously, there appear to be no good reasons to do so rather than installing a single 110 MW unit.

It is suspected that the reason for settling on multiples of 55 MW units is largely historical: at one stage these were the largest units available and became a de facto industry standard. But larger, well proven units are now available from the same manufacturers with the largest currently installed in New Zealand, having a name plate rating of 132 MW and in fact producing up to 140 MW. The first 110 MW unit was installed in Wayang Windu in the late 1980s, so it is not as if the concept is unknown in Indonesia.

This issue was discussed with PGE during the feasibility studies and financial negotiations for Ulubelu 3 and 4, and it was pointed out by the consultants that a saving of about 20% would be possible by installing a single 110 MW unit. Based on an analysis by AECOM, there were no grid constraints on the use of a single larger unit. Despite this PGE has persisted with the concept of a 2 x 55 MW plant, and the only explanation given has been that it was considered too difficult to change the PPA that had already

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[5] Noting that steam turbines do not run as efficiently at part load, so if there is uncertainty about the long term resource capacity, it may be better to install smaller units.

[6] It is worth noting that the amount of equity required to get to the "resource proven" stage for a 55 MW development will not be much less than for a 110 MW development.

been signed with 2 x 55 MW units specified. This appears to be a very weak reason for accepting a more expensive development.

It takes approximately the same length of time to manufacture and install a 110 MW unit as a 55 MW unit, so in that sense there are no time savings to be made. But logically, if a particular plant can be commissioned for a significantly lower cost, it ought to be easier to finance so in that regard could accelerate the program. This is one area where the involvement of more experienced commercial partners may help with the PGE development plan (Section 9).

Use of Other Than New Units

Elsewhere in the world, good use has been made of secondhand (some unused) and reconditioned[7] geothermal steam turbines, which are available at lower prices than new units, but more significantly may be available much faster, in less than 1 year compared to 2–3.

There is also a specific opportunity with the availability of unused but technically "obsolete" steam turbines originally manufactured for naval marine use in the US, which are now being reconfigured for geothermal use elsewhere. These are not only cheaper, but available much more quickly than newly manufactured units. In both cases there may be issues of efficiency: the older plants may require more steam per MW, and therefore more wells, but this is usually more than offset by the cost of the plant. Reliability is less of an issue since manufacturers or reconditioner's guarantees are often available.

The biggest obstacle to the use of such plant in Indonesia so far is believed to have been that government procurement processes preclude the use of other than newly manufactured plant. However it is a moot point whether such restrictions would necessarily apply to independent power producers (IPPs) or to joint ventures with PGE.

Flexibility in Deployment

There are several instances in the world where plants have been ordered for a particular project and then switched to a different project by the same owner when for some reason the original project became stalled or delayed. This included some of the Philippine National Oil Company–Energy Development Corporation plants in the Philippines and others in New Zealand and Nicaragua.

Such opportunities may arise, and can be a means to keep the overall program moving when there are unexpected difficulties such as poor drilling results or land access issues with any particularly project. To be able take advantage of these opportunities requires significant flexibility by the developer, the lenders, and the off-taker, to an extent that has not been apparent so far in Indonesia. But with the incoming of more flexible business arrangements, such as the commercial partnerships with PGE, it may be worth discussing such concepts.

7 There may be a need to convert them from 60 Hz operation as in the US to 50 Hz operation as in Indonesia, but this has been successfully done elsewhere, e.g., for the 55-MW Poihipi plant in New Zealand (shown in Figure 3.3).

Appendix 6

Cost of Exploration

This appendix presents an estimate of the minimum total cost of an exploration program in Indonesia over the next few years.

It is assumed there has been significant basic geological reconnaissance already in Indonesia to identify a sufficient portfolio of prospects. The following basic assumptions can be made as to average costs per prospect:

Stage 1: Surface geoscientific exploration, baseline environmental studies, prefeasibility study, etc. (i.e., everything prior to drilling): $1 million.

Stage 2: In the feasibility study, the cost of exploration drilling and well testing for two to four wells is conservatively estimated at $25 million, while noting that depending on location the actual costs could be significantly higher. That includes environmental permitting and infrastructure, but it does not include corporate costs in tendering etc., which may be significant but would never be funded by an external agency. With regard to infrastructure, it is worth noting that the easiest prospects to access have probably already been developed, so infrastructure costs can be expected to rise as more and more remote prospects are accessed. A figure as high as $50 million could be correct in some cases.

Stage 3: Costs at this stage comprise delineation drilling, preliminary engineering designs, and updated feasibility studies i.e., everything additional of a technical nature that is needed prior to financial closure. Once again, corporate costs are excluded. At this stage, costs will be proportional to the size of the project. If it is assumed that:

- one successful production well and one successful reinjection well are drilled in stage 2;
- 70% of the total wells are required to get to the end of stage 3;
- an average 7 MW output;
- a 2:1 production to reinjection ratio (but an integral number of wells must be drilled);
- a 75% success rate in drilling;
- a cost of $6.5 million per well including infrastructure and testing; and
- preliminary engineering and feasibility costs $1 million per project.

Then stage 3 costs for various project sizes will be as follows:

55 MW: $62 million

110 MW: $136 million

220 MW: $278 million

These costs will be applied to the development schedule in Table A3.1, making the following assumptions:

- The number of wells is based on the project capacities ignoring binary plants.
- Projects with a total capacity of 10 MW or less are omitted.

- The total MW excludes binary plants that could add about 15% to the MW total.
- Exploration costs are assumed to be spent an appropriate amount of time before power plant commissioning, i.e., for example stage 3 costs will be complete at least 2 years before commissioning.
- Where it is known that certain milestones have already been achieved (e.g., stage 2 complete), that is taken into account.
- Where projects are undertaken in a number of small stages, it is assumed that only limited further exploration is required for the later stages.
- This excludes projects scheduled for development but considered unfeasible.
- Therefore the true total cost could be higher, assuming someone does decide to explore those.
- No preinvestment for projects that will be commissioned after 2020 is included.
- MW for projects that have already had their exploration completed but which are not yet completed (e.g., Ulubelu 3 and 4) are included.

Table A6.1 reflects the additional expenditures required from now until financial closure (i.e., funding which cannot be obtained from conventional commercial sources), together with the MWs achievable by certain milestone dates.

Table A6.1: Expenditures Required through Financial Closure and Milestone MWs

Year	2014	2015	2016	2017	2018	2019	2020	Total
Expenditure ($ million)	434	704	799	609	322	0	0	2,869
Cumulative new MW	40	40	273	993	1,633	2,408	3,008	3,008

MW = megawatt.

Source: Authors' calculations.

Appendix 7

The Geothermal Tariff Issuance of June 2014

The recommendations on the mechanism of ceiling tariff and tender process improvements were provided to the Directorate General of New and Renewable Energy and Energy Conservation of the Ministry of Energy and Mineral Resource (MEMR) as Tariff Methodology Report in April 2014. After several follow-up meetings between the staff of MEMR, geothermal stakeholders, and the Asian Development Bank (ADB)–World Bank team, MEMR issued a new regulation (MEMR Regulation No. 17, 2014) in June 2014 to replace the previous regime of FITs with a competitive tender scheme with benefit-based ceiling prices. This change will likely be a major step forward in improving the Indonesian geothermal regulatory framework.

Key Provisions of Ministry of Energy and Mineral Resources Regulation No. 17/2014

Ceiling Prices Based on Benefits

The new regulation sets the ceiling prices by region and target commercial operation date (COD) year. Three regions are determined based on main generation sources. Region 1 consists of Sumatra, Java, and Bali, in which geothermal would replace power from large coal-fired power plants. Region 2 includes other areas where small coal-fired power plants are planned to be the main source of power such as Sulawesi, West Nusa Tenggara, East Nusa Tenggara, etc. Region 3 covers any areas where isolated diesel generation is the primary source of power.

The values of the new ceiling prices are shown in Table A7.1. The prices are slightly lower than the recommended figures in this report due to adjustments on some of the parameter values by MEMR. However, these prices appear to be in line with the calculation of avoided costs in the tariff methodology report by ADB–World Bank.

Table A7.1: New Ceiling Prices

	Region 1	Region 2	Region 3
2015	11.8	17.0	25.4
2016	12.2	17.6	25.8
2017	12.6	18.2	26.2
2018	13.0	18.8	26.6
2019	13.4	19.4	27.0
2020	13.8	20.0	27.4
2021	14.2	20.6	27.8
2022	14.6	21.3	28.3
2023	15.0	21.9	28.7
2024	15.5	22.6	29.2
2025	15.9	23.3	29.6

Source: Government of Indonesia, Ministry of Energy and Mineral Resources. Ministerial Regulation No. 17/2014.

Provision of Model Power Purchase Agreements at Tender

The new regulation also requires PLN to provide a model power purchase agreement (PPA) at the tender stage. In the previous regulations, the role of PLN in tender was not clear. In some cases, PLN was expressly excluded from the process by an MEMR instruction.

Revocation of *Izin Usaha Pertambangan* (Mining Business Permit) Without Progress

The regulation requires existing *Izin Usaha Pertambangan* (mining business permit) (IUP) holders to complete their PPA negotiation processes with PLN and preparation for exploration between August and December, depending on the progress of licensing processes in each field. For example, for an existing IUP holder that has obtained the MEMR approval on the selling price but cannot conclude a PPA with PLN by August 2014, its IUP will be revoked and the corresponding *wilayah kerja pertambangan* (geothermal work area) (WKP) will be retendered.

Key Differences Between Ministry of Energy and Mineral Resources Regulation No. 17/2014 and ADB–World Bank Recommendations

Updating Mechanism for Ceiling Prices

The ADB–World Bank team recommended that the new scheme incorporate a mechanism to update the values of ceiling prices annually. The need for updates arises as parameters from the international energy markets such as coal prices may change significantly over time. MEMR's regulation makes no provision for such updating.

Transparent Mechanism for Price Setting

While the regulation does not preclude seeking access to the methodology used to set the ceiling prices, the ADB–World Bank team recommended that the methodology should be transparent so that the government's assumptions and ceiling prices are well justified. It would help if the government posted the methodology report on MEMR's website.

Clarity on the Role of the Geothermal Fund in Tender Processes

There is no indication of the mechanism to incorporate the use of the Geothermal Fund in the new regulation. If the recovery cost for the exploration by the Geothermal Fund is clearly stated as bidder's obligation in tender documents, the ceiling prices may not need adjustment, as developers can incorporate the cost in their price calculations. However, such requirements for central and local governments at the tender stage are not clarified in the regulation. In our previous discussions, MEMR plans to clarify the role of Geothermal Fund in the revision of government and ministerial regulations on the tender mechanism (PP59/2007 and MEMR 11/2008) as soon as the geothermal law revision is approved.

Central Tender Authority

The MEMR Regulation No. 17/2014 is based on the tender mechanism by central or local governments. However, the new bill on geothermal has shifted this authority to the central government. While this change is in line with our recommendation, technical assistance will likely be needed to ensure the quality of tender documents and evaluation processes.

Transparent Escalation Mechanism

The current escalation mechanism is determined at the PPA negotiation stage between the winning bidder and PLN. This ad hoc process has led to time-consuming negotiations. Developers are also left with uncertainties over the escalation mechanism until after they submit their bids. Therefore, a transparent mechanism set by the government would facilitate this negotiation process and accelerate the conclusion of PPAs for both PLN and developers.

Appendix 8

The New Geothermal Law 2014

On 26 August 2014, Indonesia's House of Representatives passed the Bill on Geothermal Energy as a revision to the current Geothermal Law No. 27 of 2003. The bill provides improvements to some of the issues that have hindered geothermal projects in Indonesia, namely:

- distribution of authority of government institutions over direct and indirect use of geothermal resources;
- licensing procedures; and
- forestry issues in geothermal development.

The bill distinguishes between the direct use (for example, tourism, industry, and agribusiness) of geothermal resources and their indirect use (electricity generation). While the 2003 Geothermal Law assigns authority over geothermal resources for both direct and indirect use to central and/or provincial and/or regency governments, the 2014 bill assigns authority for licensing indirect use of geothermal resources to the central government only, represented by MEMR. However, the authority for direct use of geothermal resource remains the same as the 2003 law, and is held by central and/or provincial and/or regency government based on its location.

The new arrangement for government authority over the indirect use of geothermal resource will allow MEMR to conduct all geothermal concession tenders. While a new government regulation is required to set out the new requirements for the tender mechanism, centralized tender management is in line with the recommendations in this report. The interest of local governments in geothermal development is secured by a new production bonus, starting on the date of commercial operation, levied in addition to any applicable local taxes.

The 2003 law stipulated only that the Minister of MEMR could conduct exploration, but did not specify whether any outside entities could be assigned to conduct exploration. The new bill states that the Minister of MEMR can appoint other entities to conduct exploration. Again, while the details are left to the new implementation regulation, this change may provide resolution to the issues of the exploration authority for the Geothermal Fund.

The licenses of geothermal development consist of a Geothermal License (for indirect use and issued by central government) and a Direct Use License (issued by central or provincial or regency government).

- The Geothermal License for electricity generation may last up to a total of 37 years (a maximum of 7 years for exploration, which includes feasibility study preparation, and 30 years for exploitation). Prior to the expiration of license, developers may apply for an extension of a maximum of 20 years.

- When the bill officially becomes law, the legacy geothermal concessions will be valid for 30 years from the date of the enactment. The existing concessions (IUPs) under Geothermal Law 2003 and joint operation contracts will also be valid until the expiration of the license or the joint operation contract.

The declassification of geothermal as “mining activity” allows greater latitude for the geothermal development in the protected and conservation forests. Developers are required to secure borrow-to-use permits if the *wilayah kerja pertambangan* (geothermal work area) is located in a production forest or protected forest, or a forestry utilization permit if the work area is located in a conservation forest.

Unlocking Indonesia's Geothermal Potential

This report was produced jointly by the Asian Development Bank and the World Bank and is based on a series of technical assistance activities conducted during 2013-2014. The study documents key issues that have constrained the development of Indonesia's geothermal power development sector, including tariffs, tendering processes, financial considerations, permitting, and inter-agency coordination. The report then makes a set of comprehensive recommendations to unlock the potential of the sector, including a new tariff regime, improvements to the tendering process, re-negotiation of power purchase agreements, and innovative modes of financing and project de-risking.

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