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# USAID VIETNAM LOW EMISSION ENERGY PROGRAM (V-LEEP)

## Report: Assessment and Recommendations on Methodology for Power Development Plan (PDP)

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# USAID VIETNAM LOW EMISSION ENERGY PROGRAM (V-LEEP)

## Report: Assessment and Recommendations on Methodology for Power Development Plan (PDP)

Prepared for:

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### ABOUT NREL

The National Renewable Energy Laboratory is a national laboratory of the U.S. DOE, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC. under the Greening the Grid initiative, supported by USAID. NREL collaborates with V-LEEP to provide technical assistance to the Government of Vietnam (GVN) in strengthening its enabling environment, including its power sector planning processes, to address technical challenges around grid modernization and advance state-of-the-art practices in bringing advanced energy technologies into the power sector.

### ABOUT HNEI

The Hawaii Natural Energy Institute (HNEI), a research unit of the School of Ocean and Earth Science and Technology (SOEST), University of Hawai'i at Manoa (UHM), conducts research of state and national importance to develop, test and evaluate novel renewable energy technologies. The Institute leverages its in-house work with public-private partnerships to demonstrate real-world operations and enable integration of emerging technologies into the energy mix. Founded in 1974, HNEI was established in statute in 2007 to address critical State energy needs.

# ABBREVIATIONS AND ACRONYMS

| | |
|---|---|
| AC | alternating current |
| ACT | Avoided Cost Tariff |
| ADB | The Asian Development Bank |
| BAU | business-as-usual |
| BESS | battery energy storage system |
| BOT | Build-Operate-Transfer |
| CCGT | combined cycle gas turbine |
| CGE | computable general equilibrium |
| CNG | compressed natural gas |
| COD | Commercial Operation Date |
| CPU | central processing unit |
| DC | direct current |
| DEA | Danish Energy Agency |
| DEESD | Department of Energy Efficiency and Sustaintable Development |
| DER | distributed energy resource |
| DG | distributed generation |
| DR | Demand Response |
| DSM | Demand Side Management |
| DSO | Distribution System Operator |
| EE | Energy Efficiency |
| EEU | Expected Energy Unserved |
| ELCC | Effective Load Carrying Capacity |
| ERAV | Electricity Regulatory Authority of Vietnam |
| EREA | Energy and Renewable Energy Authority |
| EV | electric vehicle |
| EVN | Electricity of Vietnam |
| FIT | feed-in tariff |
| GAMS | General Algebraic Modeling System |
| GDP | Gross Domestic Product |
| GENCO | Generation Company |
| GHG | greenhouse gas |
| GIS | Geographic Information System |
| GtG | Greening the Grid |
| GVN | Government of Vietnam |
| GW | gigawatt |
| GWh | gigawatt hour |

| | |
|---|---|
| HNEI | Hawaii Natural Energy Institute |
| IEA | International Energy Agency |
| IEVN | Institute of Energy of Vietnam |
| IGP | Integrated Grid Planning |
| IPP | Independent Power Producer |
| IRENA | International Renewable Energy Agency |
| IRP | Integrated Resource Planning |
| kgOE | kilogram of oil equivalent |
| LACE | Levelized Avoided Cost of Energy |
| LCOE | Levelized Cost of Electricity |
| LEAP III | (USAID) Learning, Evaluation, and Analysis Project |
| LNG | Liquified natural gas |
| LOLE | Loss of Load Expectation |
| LOLH | Loss of Load Hours |
| LOLP | Loss of Load Probability |
| LT | long-term |
| LWR | Least Worst Regret |
| MIP | mixed-integer programming |
| MOIT | Ministry of Industry and Trade |
| MONRE | Ministry of Natural Resources and Environment |
| MPI | Ministry of Planning and Investment |
| MT | medium-term |
| MW | Megawatt |
| MWG | Modelling Working Group |
| MWh | megawatt hour |
| NLDC | National Load Dispatching Center |
| NOA | Network Options Assessment |
| NPT | National Power Transmission Corporation |
| NREL | (US Department of Energy) National Renewable Energy Laboratory |
| NTP | National Technical Potential |
| NWP | numerical weather prediction |
| ODA | Official Development Assistance |
| OECD | The Organisation for Economic Co-operation and Development |
| O&M | Operation and Maintenance |
| PC | Power Company |
| PPA | Power Purchase Agreement |
| PPC | Provincial People's Committee |
| PSHP | pump-storage hydropower plant |

| | |
|---|---|
| PSIP | Power Supply Improvement Plans |
| PV | photovoltaic |
| PVN | PetroVietnam |
| RE | renewable energy |
| REC | Renewable Energy Certificate |
| RES | Renewable Energy Resource |
| RFP | request for proposals |
| RPS | Renewable Energy Portfolio Standard |
| SAM | System Advisor Model |
| SCADA | Supervisory Control and Data Acquisition |
| SHP | small hydropower plant |
| SMHP | strategic multipurpose hydropower plant |
| SMO | System and Market Operator |
| ST | short-term |
| TAG | Technical Advisory Group |
| TMY | typical meteorological year |
| T&D | transmission and distribution |
| TOE | tonne of oil equivalent |
| TSO | Transmission System Operator |
| UK | United Kingdom |
| USAID | United States Agency for International Development |
| V-LEEP | Vietnam Low Emission Energy Program |
| VNEEP | Vietnam National Energy Efficiency Program |
| VRE | variable renewable energy |
| VREM | Vietnam Retail Electricity Market |
| VWEM | Vietnam Wholesale Electricity Market |
| WB | The World Bank |

# EXECUTIVE SUMMARY

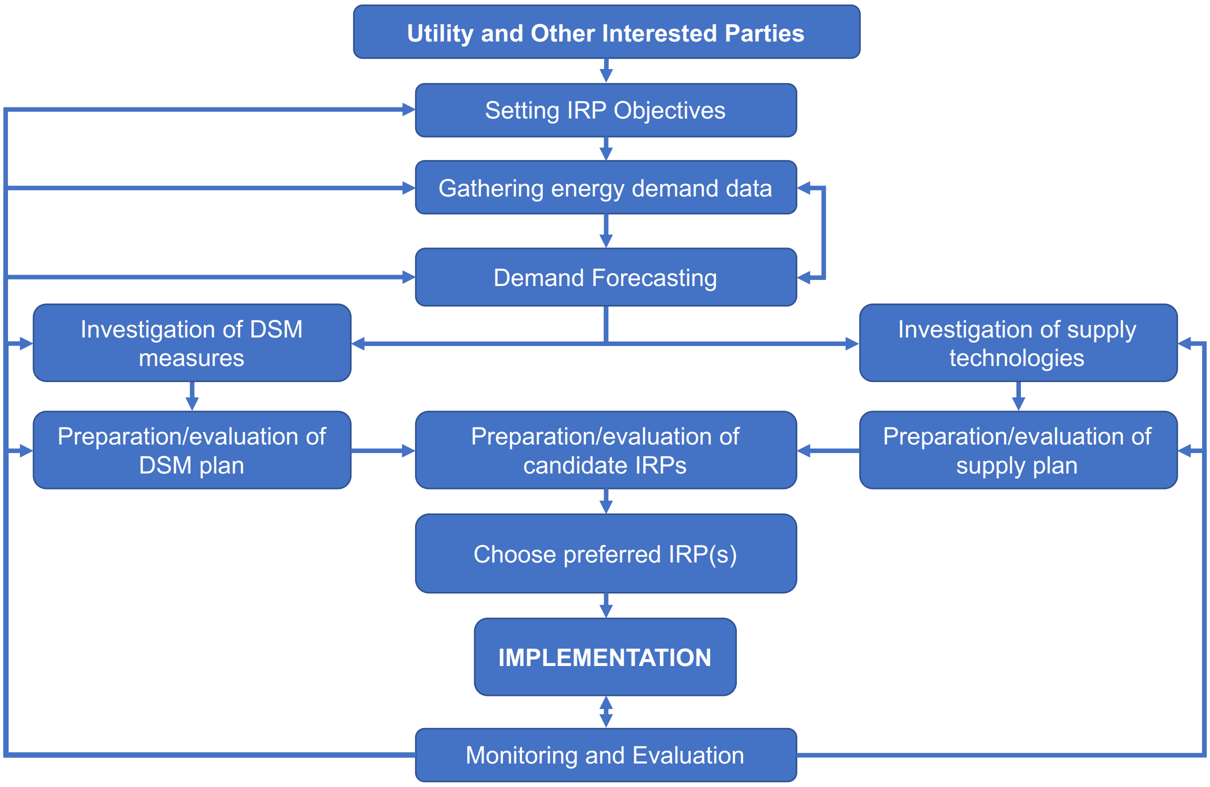
International leading practices for power system planning are founded upon the core functional steps, processes, and methodologies that have traditionally been employed by utilities, system operators, and government agencies. IRP-based least-cost planning is transforming the planning process traditionally used in the electric utility industry. As compared to the traditional planning process, least-cost planning broadens the participation by multiple parties and widens the range of the planning options that are assessed. Its integrative nature opens consideration of multiple planning objectives (such as social, environmental, and economic objectives) in evaluating demand-side and supply-side options.

Integrated Resources Planning (IRP) is an energy planning process first introduced in the United States in the 1980s to deal with the situation where several power plants were found not needed and thus led to serious cost and time overruns. The term “resource planning” refers to the development of plans for ensuring that adequate generation resources will be available to meet long-term power needs (IRENA 2018). It differs from traditional power development planning processes, which focus on “supply-side” projects only, in that IRP considers a full range of feasible supply-side options (generation sources, transmission, and distribution) and demand-side measures needed to meet new demand for electricity, and assesses them against a common set of planning objectives and criteria (Nichols and Hippel 2000). This approach will require power planning experts to develop detailed information on demand-side options including estimated installed costs, peak demand and hourly profile demand impacts on a daily basis for monthly or perhaps seasonal basis.

IRP plans use long-term (20-30 year) planning horizons and include careful consideration of risk. Best practice IRPs integrate environmental and other external costs and benefits, and require that planners work together with other interested parties to identify and prepare energy options that serve the highest possible public good. When done properly, IRP provides a structure and an opportunity for power system planners and stakeholders to learn and to develop plans in a co-operative atmosphere, and can lead to better outcomes: lower cost electricity, lower risk from price volatility, and lower social and environmental impact (Greacen, et al. 2013). When reviewing the various options and potential future scenarios, the total emission levels for each option and future scenario are explicated calculated by the models (given that air emission rates for the thermal powered plants are usually available) so that the planners can see the costs and environmental impacts simultaneously. Over time the PDP planners can develop externality costs of environmental impact into the models.

The IRP process is also recommended by the International Renewable Energy Association (IRENA) for power planning with higher variable renewable power (IRENA 2017). It is necessary to emphasize that IRP can be resource-intensive, time-consuming, and require specialized expertise in economics, power system modelling and other disciplines. However, IRP enables planners and decision makers to satisfy long-term power demands with the most affordable resource portfolio, while satisfying all legal requirements and public policy objectives, with due consideration of risks and uncertainties.

The figure below describes a typical IRP process for electric systems, with discussion of various elements and steps to follow.




Least-cost planning is a process by which electric utilities or state management agencies on power sector evaluate the costs, benefits, and risks of different resources for meeting electric power demand (including traditional power plants and energy efficiency) to arrive at the mix of resources that will meet future demand at the lowest cost while still providing reliable electric service. With a growing queue of solar and wind energy project proposals, Vietnam's power sector planners have articulated major concern about the capability of the power system to absorb high variable RE penetration levels without experiencing significant operational or reliability challenges. Another challenge would be the uncertainty of resources available/committed for power system expansion. It is essential that the new PDP process use state of the art methods, practices and tools, but also adopting/re-using the robust PDP process and capacity expansion models being developed through previous efforts.

The PDP methodology used for previous PDPs may have been fine at the time but is inadequate for PDP-8. The methodology does not do a thorough enough analysis of how the system can, or cannot, operate, therefore an operations analysis should be added to test the feasibility of the expansion plans proposed by the long-term model. In addition to performing the operations modelling, the previous methodology is lacking in that it does not collect data necessary to setup the operations model. As discussed elsewhere, additional, often more detailed data will need to be collected and used not only for direct use in the operations model, but to improve the accuracy of the demand and transmission analysis steps.

The table below shows the differences between the PDP methodology used in Vietnam and the international leading PDP practices.

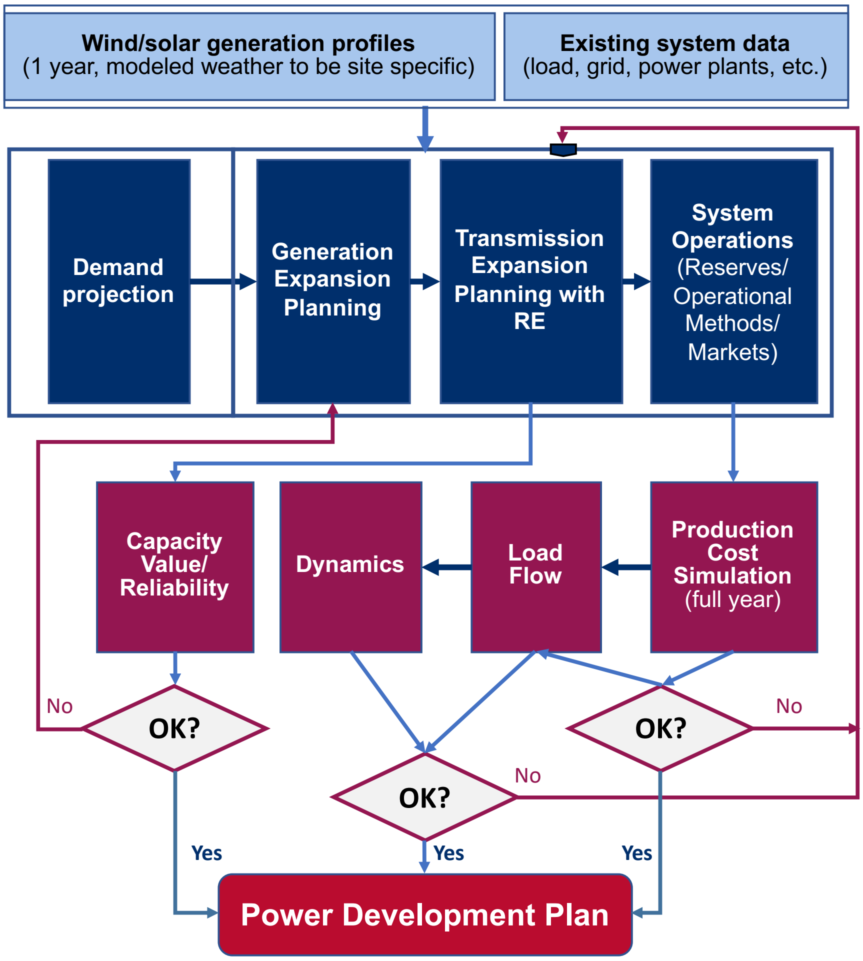
| | International leading practices | Methodology used for PDP7/RPDP7 | Remark |
|---|---|---|---|
| **Bottom-up load forecasting** | Yes | Limited | Unclear how to consolidate top-down and bottom-up results |
| **Generation costs** | Yes | Yes | |
| **Demand-side management options and costs** | Yes | No | Only national EE program (VNEEP) |
| **Transmission and distribution costs** | Yes | Limited | Only transmission (500 kV and 220/110 kV) |
| **Risks of fuel price volatility, drought, carbon taxes, etc.** | Yes | Limited | Sensitivity analysis only with deterministic fuel costs |
| **Social and environmental "externality" costs** | Yes | Limited | Lack of country specific pollution generating factors |
| **Public involvement throughout process** | Yes | Limited | Draft PDP development report only, not during the process |
| **Scenario and sensitivity analysis to ensure "least-cost" under different cost or demand assumptions** | Yes | Limited | PDPAT II with typical day/week only |

Moreover, the regions to be analyzed in PDP should not be specified in legislation nor limited by previous studies. With the advent of the competitive market, new generation resources including distributed generation will impact the marginal cost of a region. That is, new regions will appear not because of physical congestion, but due to economic congestion. As part of the overall PDP process, the determination of regions should be completed once the marginal cost of generation across the country is determined. The payback on increasing transmission to relieve economic congestion will be part of the transmission analysis.

As the proportion of variable RE in the electricity generation mix increases, traditional power planning processes evolve to take into consideration the unique characteristics (such as variability, uncertainty, and locational specificity) of solar and wind energy (Milligan and Katz 2016). Key changes for power system planning for higher levels of variable RE include:

- The need for input data that characterize the hourly or sub-hourly solar and wind generation at high spatial resolution;
- Consideration of solar and wind resource potential and geographic concentration in transmission planning; and

The need for operational modeling (i.e., production cost simulations) that covers every period (e.g., hour, 30-minute increment) of the year, rather than only example days or weeks. The general approach to power system planning can be thought of as shown in the figure below. Be cautioned that the actual study process is more complex than can be depicted in such a diagram.




With regard to **Data Collection**, two general types of data lay the foundation for the proposed new approach to PDP planning:

**1) Renewable energy generation profiles**. The use of high spatial and temporal resolution solar and wind energy generation data (i.e., modeled, gridded hourly or 30-minute time series) represents a significant new element of the proposed PDP process and will enable the PDP to better identify challenges and opportunities related to integrating variable renewable energy to the power system. In recent years, MOIT has worked with the World Bank, GIZ, and others to improve the solar and wind resource data for Vietnam. The data produced through these efforts likely can be leveraged for use in the PDP analyses, though additional processing may be needed to screen suitable areas for development (e.g., based on updated information related to land use, terrain, and other factors) and create generation profiles based on modern solar and wind energy technologies. If existing datasets are inadequate, high resolution, modeled solar and wind resource datasets are available for purchase from a variety of vendors. Given that off-shore wind is an option, information on off-shore wind-power potential must be collected.

**2) Existing system data** (at a minimum, one recent historic year of detailed demand, generator, network, and operational data). Much of these data are likely to be available from other, and relatively recent, planning studies. Exploring options to use the data in these existing models—and supplementing them to fill gaps as needed—will improve the efficiency and accuracy of the data collection process for PDP-8.

The PDP process must determine:

- the information is needed, both for overall assessment, resource screening, and system modeling

- the data is available from previous PDPs, from the sector and from the numerous IFI and donor-funded studies
- the data gaps when comparing 1) above to 2) and laying out a plan to collect that data for future PDPs
- the data for quality, consistency and sufficient quantity (for example, one or two regions rather than nationally) and developing a plan for improving the existing data

A central database with all the planning data and information should be maintained and updated on a regular, if not constant, basis.

With regard to **Demand Forecasting**, the demand forecast in PDP-8 will have to deal with greater details of regional load profiles – including more regions for allocating to the transmission nodes of the system, at an hourly or sub-hourly level (load profiles with high temporal resolution are essential inputs to operational models and renewable energy grid integration studies, which test the feasibility of balancing electricity supply and demand at every dispatch interval of the target year). Information regarding historical losses, and plans to reduce losses, will also need to be gathered and the forecast improved accordingly.

A new analytical element of PDP-8 is the addition of a bottom-up approach focusing on nonconforming load. The starting point for this will again be historical data at a granular level (time and location). Available information regarding specific demands (industrial parks, flagship projects, factories, ports, mines, agriculture, street lighting, electric trains, etc.) will be gathered. Additionally, information regarding new developments in each area, as well as changes to existing demand, will be gathered, reviewed and incorporated with historical data to develop this portion of the forecast. For example, with the increase in electric vehicle expansion, the demand patterns will be different and changing as car battery technology develops and the facilities for charging batteries develop. This bottom-up forecast will be combined with the top-down forecast to develop the overall forecasts.

With regard to **Generation Expansion Planning**, the approach will be like that undertaken in previous efforts. The overall objective will be to simulate least-cost grid expansion decisions, looking over the entire 20-30 year time horizon. PDP8 presents an opportunity for updates and innovation, including the following changes:

- **New model(s):** Consultations by the V-LEEP team indicate that the version of STRATEGIST utilized in PDP-7/RPDP-7 is out of date, and new/renewed model(s) should be considered.

- **Higher resolution of the long-term model in time and space.** One possible approach to increasing the number of zones modeled in the PDP would be required. In addition to increasing the spatial resolution, including more time slices in the capacity expansion model beyond one typical day or week will better capture the variability of both demand and supply (particularly variable renewable energy).

- **Updated technology cost and performance data.** The costs and performance characteristics of technologies such as solar PV, wind turbines, and battery energy storage have changed rapidly within the past decade. Updating cost and performance assumptions for all resources included in the capacity expansion model based on modern trends is crucial to developing a robust least-cost expansion plan.

With regard to **Transmission Planning**, in general the same approach would be applied, including annual updates of PSS@E database to have an accurate representation of today's grid, along with known plans for future years. The cases should be checked to ensure that they accurately reflect the status for all planned changes to the grid.

The most significant new component, **<u>System Operations Analysis</u>** using a production cost model, is recommended for is new component proposed for PDP-8 PDP-7/RPDP-7 included limited operational analysis, evaluating operations only over a typical day or week to simplify calculations. Moreover, planners have traditionally considered capacity expansion in terms of the need for baseload, load-following, and peaking generation capacity, with respect to a given planning reserve margin, while transmission and distribution systems were designed to accommodate peak loads. With larger amounts of variable renewables integrated into the grid (which may require increasing levels of flexibility and operating reserves from the system at times other than peak time) and as advancements in technology such as smart grids allow for more choices; as demand response options become more prevalent; etc. it is necessary to adjust the dispatching rules in a more appropriate way, in which mobilization of variable RE generation resources or applying demand response measures should be considered in prior to new transmission lines to serve peak loads.

In other words, various options can provide challenges and benefits away from the peak, which need to be evaluated. In addition, short-term variability (sub-hourly and hourly) in solar and wind energy generation should be accounted for, rather than relying on long-term average capacity factors. A failure to account for short term variability could lead to an inadequate or inefficient plan. Thus, it is no longer sufficient to consider only a few hours, snapshots, typical days/weeks; but it is necessary to evaluate all hours of the year, and likely to perform sub-hourly analysis. Planning now needs to provide sufficient ramping capabilities, upward and downward, to meet fluctuating net loads. To better understand and plan for an evolving power system with variable demand and supply, PDP-8 can incorporate a new step to use a production cost model to simulate the operation of the power system during every period (e.g., hour, 30-minute, 5-minute increment) of one or more medium-term target years (e.g., 2030). This step will have the important objective of validating the operational feasibility and operational costs of capacity expansion scenarios**.**

With regard to **<u>Modelling tools</u>**, each model has its advantages and disadvantages and therefore <u>no single model</u> is truly capable of *optimizing* the level of solar and wind in the power mix based on both fixed costs and operational considerations. Further, neither grid integration studies nor actual operational experience have yet found a physical limit to variable RE penetration in any given power system. As RE increases, system operators and planners have many options to address reliability – some no-cost, some through new infrastructure. Thus, a comprehensive PDP methodology should consider using <u>multiple models</u> to explore potential cost, operational, and reliability tradeoffs that might arise at different target levels of variable RE on Vietnam's power system. The methodology will also address how different flexibility solutions can help cost-effectively mitigate challenges that arise. The PDP results are critical in that they provide information that will be used to make decisions that have large impacts (financial, environmental, social, etc.) for the country, and the region. The software costs are insignificant in comparison with the consequences of the PDP. Since selection of the appropriate tools can have a large impact on the PDP results, it is essential that the proper tools be selected. Considerations for selection of the (long/short term) simulation tools include:

- Cost is factor but should be kept in the proper context. Solutions which may result in incorrect results may result in tremendous costs in the long term (e.g., incorrect selection of generation projects). Also, if a less expensive solution requires more effort on the part of the power system planner, the overall cost of the solution, including the planner's time, may be higher.
- Ability to accurately and natively model necessary elements of the system (power markets, cascaded hydro, hydro capabilities as a function of reservoir levels, co-optimization of energy and reserves, nodal capabilities with n-1 requirements)

- State of the art tools that are reasonably new and yet in wide use. Preferably, the tools should be using current algorithms, and not be based on algorithms that are decades old with patches to keep them current. At the same time, the tool should be in wide use, and have been used in several official and adversarial proceedings which implies they have been well challenged and tested.
- Prompt and quality support should be available. If questions arise, support staff should be available to promptly (i.e., a couple of hours) answer questions. If software fixes or enhancements needed, they should be available quickly, depending on the complexity, in a couple to several days.
- The model(s) should be relatively easy to use and manage. If multiple models are required, managing and coordinating multiple input databases adds to the complexity of, and potential for mistakes in, the process.
- It is very important that domestic expertise is developed in the modelling framework selected for the future PDPs (else the government of Vietnam would need to keep relying on expensive foreign consultancy support for PDP development), as well as that long-term sustainability of the modelling framework (e.g. in ensuring financing in the future) could be realistically ensured. There are examples (e.g. from Mexico) where the high annual licence fee for specifically PLEXOS has been a continuous challenge every year, risking its discontinuation.

A key aspect of planning is the stakeholder process. Internationally, utilities frequently are required to publicly release and defend their IRPs in front of consumer advocates, Public Utility Commissions, and other stakeholders. Transparency and data openness are required, and the open process improves results. This suggests the capacity development is required for utilities, regulators, and public / consumer advocates. The processes should include mechanisms for periodic stakeholder review of the plan.

Based on international experience, it is important to have proper stakeholder involvement in the PDP process. This can be accomplished by the formation of two groups: a **Modeling Working Group** (MWG) and a **Technical Advisory Group** (TAG). Note that this same approach has worked well in other countries (e.g., the countries associated with the first several examples in the Appendix).

It is essential that the modeling and scenarios for the PDP is undertaken by domestic experts. Expertise developed in PDP development should be used for future energy planning, adjustment of plans, analysis of measures etc. and dependanecy on foreign expertise will limit this. Modelling and scenario expertise takes long time to build (often years), and with the limited time for the PDP process existing experiences in specific modeling tools is key to ensure an effective combination of high quality analysis by foreign experts with core work done by Vietnamese experts.

# V-LEEP OVERVIEW

The United States Agency for International Development (USAID) Vietnam Low Emission Energy Program (V-LEEP) is helping the Government of Vietnam (GVN) establish an effective policy, regulatory, and incentive environment for low-emission growth in the energy sector, while simultaneously attracting public-sector and private-sector investment in renewable energy (RE) development and energy efficiency (EE). V-LEEP promotes the development of critical building blocks to scale up clean energy, such as accessible smart incentives for clean energy and EE investments, enabling a competitive environment for RE generation, enhancing renewable power grid integration, and ensuring locational concentration of clean energy generation facilities.

Three components form V-LEEP's core tasks:

Component 1: Low Emission Strategy Development for the Energy Sector

> Task 1.1: Enhance GVN capacity to analyze and develop clean energy strategies and evaluate emission mitigation options for decision-making.

Component 2: Enhance Capacity and Improve Enabling Environment for Renewable Energy Development

> Task 2.1: Enhance capacity of Vietnamese government institutions to improve the enabling environment for RE development.
>
> Task 2.2: Enhance capacity of RE developers and the private sector in large-scale RE development.

Component 3: Increase Energy Efficiency Adoption and Compliance

> Task 3.1: Enhance government capacity to strengthen energy efficiency policy implementation.

**About PDP Methodology Assessment and Recommendations**

Under the scope of Component 1, the Electricity and Renewable Energy Authority (EREA) would like a new guiding framework as a methodology roadmap to update the historical power development plan (PDP) process and to incorporate international good practices for planning for higher levels of variable renewable energy (VRE). To recommend such a methodology roadmap, V-LEEP team (led by Ha Dang Son, and supported by Nguyen Hoai Nam, Nguyen Trong Nghia, Ajit Kulkani and Jake Delphia) in collaboration with the US Department of Energy's National Renewable Energy Laboratory (NREL) and the Hawaii Natural Energy Institute (HNEI) have conducted this assessment to identify the advantages and disadvantages of previous PDP preparation, the changes needed to be made, and the technical and institutional set-up requirements of agencies involved in preparation of the PDP. Based on the results of this assessment, V-LEEP will collaborate with EREA to suggest a new process for PDP-8 preparation that includes specific steps and a roadmap for implementation.

# SECTION 1: BACKGROUND

## 1.1. OVERVIEW

Vietnam's Electric Power Sector is expected to undergo significant changes and growth over the coming years. One of the main drivers of this change is the substantial growth expected in electricity demand. In addition, the nature of the demand will likely change, as customers adopt new technologies and methods. The generation, transmission and distribution systems will have to grow and evolve to meet this changing demand. The system needs to grow in such a way as to ensure that demand can be met reliably, safely, transparently and economically. This should all be done in an environmentally responsible manner, meeting the various government goals and policies of today and tomorrow, while taking advantage of new trends and technologies, e.g. energy efficiency, demand response, renewable energy, distributed generation, smart grid, battery storage.

Revisions to the PDP process is essential to accomplishing the above. The PDP must forecast the electricity demand and determine the best way to meet it, considering criteria of the type mentioned above. It must evaluate a multitude of different options (e.g., thermal generation, hydro generation, RE, imports, exports, various transmission projects) to come up with the best plan. It must consider different scenarios and sensitivities (e.g., varying demand, hydro/rainfall, fuel prices, fuel security, project delays) to evaluate uncertainties and risks, weigh them against cost and reliability issues and come up with the best set of plans. The PDP must also consider and evaluate different options related to government policies and the changing power sector (e.g., renewable energy portfolio standard, evolving power market). All of these must be coordinated with other infrastructure and national aspects (e.g., availability of land, environmental and social impacts; availability of rail, ports, pipelines, and roads; water use issues; domestic vs. imported fuels).

The results of the PDP are used to guide the sector on the development of new generation and transmission projects. These typically have a few to several years of development time associated with them, have tremendous costs and have significant impacts on the economy, society and environment. They also have impacts on other sectors, such as the ability to site new industrial development and the need for new infrastructure projects to support the electricity sector. Hence, it is essential to do a proper and thorough analysis during the development of the PDP, as the consequences of a suboptimal PDP can be substantial. Though it will take some cost and effort to develop the PDP, it pales in comparison to the cost and time associated with the projects, and associated implications, that are likely to result from the PDP.

## 1.2. PURPOSE OF THE PDP

The basic objective of a PDP, or similar type of analysis, is to determine the most economical power system development plan that will allow the forecasted demand to be met in a reliable and secure manner. The analysis invariably includes multiple scenarios and sensitivities to assess the robustness of the plan given the uncertainties in the forecasts. Hence, the results are likely to include a set of plans to cover a range of possibilities. As part of such an analysis, in addition to addressing the basic objective, there will likely be a set of additional questions to be considered.

One such item is the specific generation mix. It is essential to consider alternatives, dependent infrastructure, and their technical characteristics, capabilities, dependencies, timelines and costs. For example, when considering generation alternatives such as gas, coal, nuclear, wind, solar, it is important to understand the project specific timelines and challenges, costs, technical characteristics that vary by site, the specific nature of the resource at the site (e.g., site specific wind resource data) any infrastructure that needs to be built to support the project and the associated costs and timelines with that infrastructure (e.g. new transmission, new road). The PDP methodology needs to evaluate these in detail, so that alternatives can be weighed against each other and plans with the appropriate options can be developed.

Additionally, the PDP must evaluate, as appropriate, imports/exports from/to neighboring countries. These will have specific locations in the transmission system where they will be delivered/withdrawn, and will have specific characteristics (e.g., nominal capacity, energy limits, hourly/weekly/seasonal/annual limits, baseload, flexibility, ancillary services, costs) to be evaluated. These need to be evaluated in conjunction with other supply and demand options to evaluate reliability and determine cost implications.

Demand side options must also be included in the PDP as appropriate. As with other options, they may have dependencies on infrastructure, have specific costs, have specific timelines, be implemented in specific locations, and technical characteristics and availability which need to be evaluated to determine the costs and benefits to the system, and evaluated against other options.

The PDP must be able to evaluate different transmission options in terms of technical performance, benefits, risks and costs. This will be needed in terms of backbone grid improvements and generation specific improvements evaluated as part of the specific generation project. The PDP should also evaluate the system value of alternative transmission improvements, where one alternative may provide more value than another over the study horizon of the PDP. For example, there may be some congestion on the system which is causing some generation curtailment and redispatch. The PDP must be able to evaluate the additional operating costs of the latter, so that it can be compared to the cost of the transmission upgrade.

Vietnam will certainly consider implementing various policies and regulations that impact the power system, during the PDP horizon. Examples might include renewable energy portfolio standard (RPS), emissions limits or taxes, demand response (DR)/demand side management (DSM), electric vehicles (EVs), industrial/flagship demand and further evolution of the power market. Such policy decisions have power system costs, benefits, risks and uncertainties which must be evaluated so that informed policy decisions can be made. Once the desired policy changes are selected, their impact on plan(s) must be appropriately assessed in the PDP analysis.

For all the above, costs (capital, operating), value, benefits, timing, reliability, dependencies and impacts on other infrastructure and projects must be evaluated.

Additionally, the PDP should be able to provide essential information to support contract negotiations. This would include costs and technical performance information and implications to support PPA negotiations, fuel contract negotiations, O&M contract negotiations, etc.

## 1.3. SCOPE OF THE STUDY

Specific activities within the scope of the PDP methodology assessment are:

- Develop a detailed PDP process work flows based on international good practices for planning for higher levels of variable RE, as a reference case for assessment;
- Assess the entire PDP preparation process, and address the advantages and disadvantages of previous PDP preparation processes;
- Recommend an advanced and appropriate methodology for the PDP-8;
- Present key findings and recommendations in a stakeholder consultation workshop.

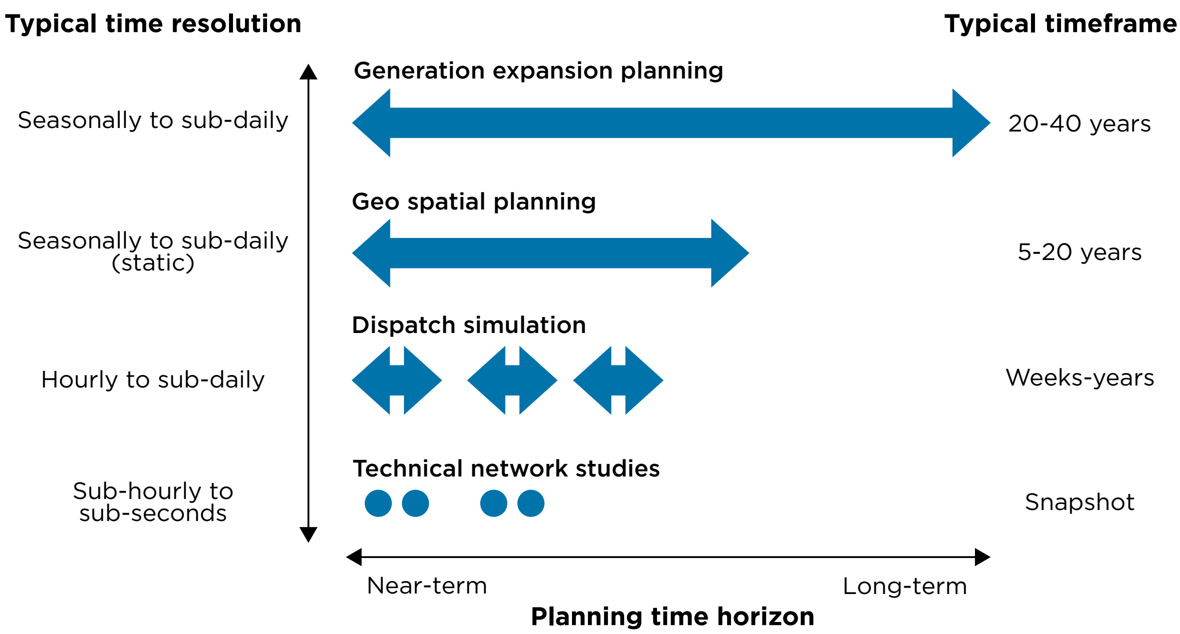
For this assessment, a team comprising an international expert and three local experts having extensive experiences in power planning have been mobilized from July 2018. In an intensive fact finding mission from August 13-31, 2018 the team met with representatives from key stakeholders (EREA, ERAV, MOIT Department of Coal-Oil-Gas, IEVN, EVN, GENCO 1) to (i) gather information and feedback on the Seventh National PDP (PDP-7) and the Revised PDP-7 (RPDP-7); and (ii) identify the possible needs for an updated PDP process to be recommended for the PDP-8. The agenda of fact finding meetings and the list of people met are presented in Appendix A2.

Additional technical supports were provided by the US Department of Energy's National Renewable Energy Laboratory (NREL) and the Hawaii Natural Energy Institute (HNEI) on specific topics ralated to advanced power system planning and renewable energy grid integration, to build the foundation for methodology assessment and recommendations.

## SECTION 2: INTERNATIONAL GOOD PRACTICES ON PDP

The discussion in the previous section about the objectives and needs for PDP type of analysis is applicable to many countries of the world. To accomplish the above, a significant attempt is made to use state of the art tools, methods and skills. In terms of the time horizons for such analysis, one needs to keep in mind the types of projects in the PDP, as well as the indirect projects (e.g., transportation), take significant time to develop and have significant life spans. For example, generation projects take anywhere from a couple to several years to develop depending on the type of generation and can have life spans of 25+ years. To properly evaluate such options, most PDP analysis should be done, and is done, over a 20-40 year time horizon (Figure 1).

***Figure 1: Transition planning components and time horizon***




*Source: From (IRENA 2017)*

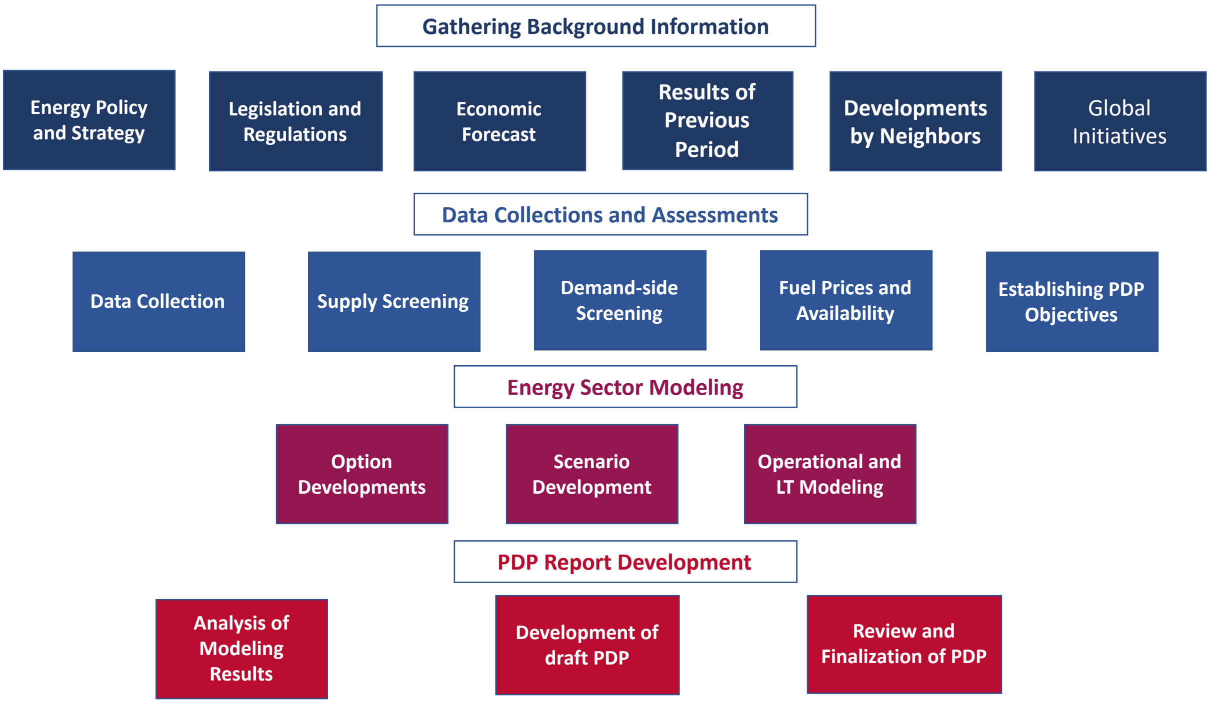
In today's world, information related to the inputs of a PDP type of study can change relatively rapidly (e.g., project status, fuel costs, RE costs, factors affecting demand) and the analysis is typically updated at least every two years, if not more frequently. A good practice is to evaluate the inputs and assumptions, on an annual basis, to determine where significant changes have occurred, and perform a focused update based on those changes. In some cases, limited updates are completed for up to a couple of years. After that, based on an evaluation of changes to inputs and assumptions, complete updates are conducted.

**Changing to a much shorter time frame for updating the power development plan would be a major change for Vietnam**. International experience shows that monitoring the energy sector for the identified key variables (demand, fuel prices and availability, generation prices, process delays) will help the country better manage the risks of under and over building its infrastructure. An alternative to the existing methodology of fixing the PDP update at 10 years is to have a monitoring function within the MOIT that identifies the circumstances that would trigger the need for an updated PDP.

## 2.1. APPROACH AND WORK FLOW

International leading practices for power system planning are founded upon the core functional steps, processes, and methodologies that have traditionally been employed by utilities, system operators, and government agencies. These include load forecasting, fuel price forecasting, scenario selection and uncertainty quantification, portfolio selection, transmission system requirement assessment (integrated with generation planning or in parallel), social/environmental evaluation, and risk assessment against scenarios and uncertainty.

***Figure 2: PDP Major Steps***




*Source: Elaborated by V-LEEP team.*

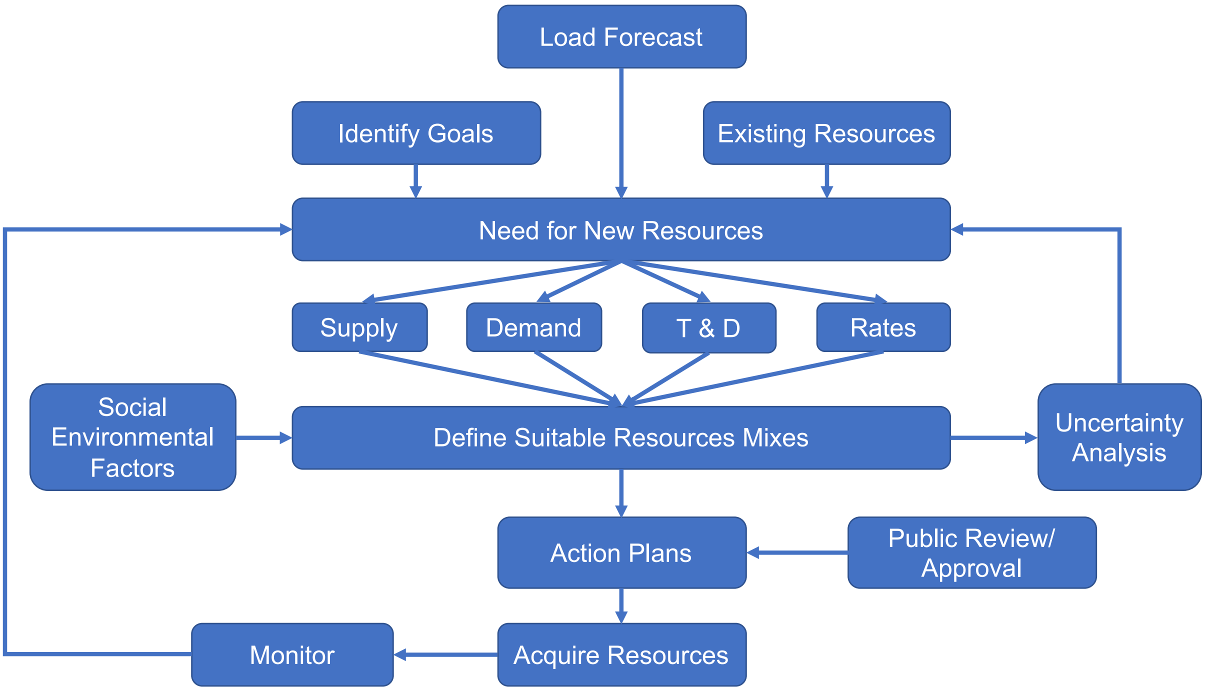
### 2.1.1. INTEGRATED RESOURCE PLANNING

Integrated Resources Planning (IRP) is an energy planning process first introduced in the United States in the 1980s to deal with the situation where several power plants were found not needed and thus led to serious cost and time overruns. The term "resource planning" refers to the development of plans for ensuring that adequate generation resources will be available to meet long-term power needs (IRENA 2018). It differs from traditional power development planning processes, which focus on "supply-side" projects only, in that IRP considers a full range of feasible supply-side options (generation sources, transmission, and distribution) and demand-side measures needed to meet new demand for electricity, and assesses them against a common set of planning objectives and criteria (Nichols and Hippel 2000). This approach will require power planning experts to develop detailed information on demand-side options including estimated installed costs, peak demand and hourly profile demand impacts on a daily basis for monthly or perhaps seasonal basis. On an interim basis, similar data may be obtained from other regional countries until the data is developed in Vietnam.

IRP plans use long-term (20-30 year) planning horizons and include careful consideration of risk. Best practice IRPs integrate environmental and other external costs and benefits, and require that planners work together with other interested parties to identify and prepare energy options that serve the highest possible public good. When done properly, IRP provides a structure and an opportunity for power system planners and stakeholders to learn and to develop plans in a co-operative atmosphere, and can lead to better outcomes: lower cost electricity, lower risk from price volatility, and lower social and environmental impact (Greacen, et al. 2013). When reviewing the various options and potential future scenarios, the total emission levels for each option and future scenario are explicated calculated by the models (given that air emission rates for the thermal powered plants are usually available) so that the planners can see the costs and environmental impacts simultaneously. Over time the PDP planners can develop externality costs of environmental impact into the models.

The IRP process is also recommended by the International Renewable Energy Association (IRENA) for power planning with higher variable renewable power (IRENA 2017). Figure 3 below summarizes the key steps to conduct an IRP process, as recommended to electric utilities and regulators in the United States.

***Figure 3: Flow chart for Integrated Resource Planning***

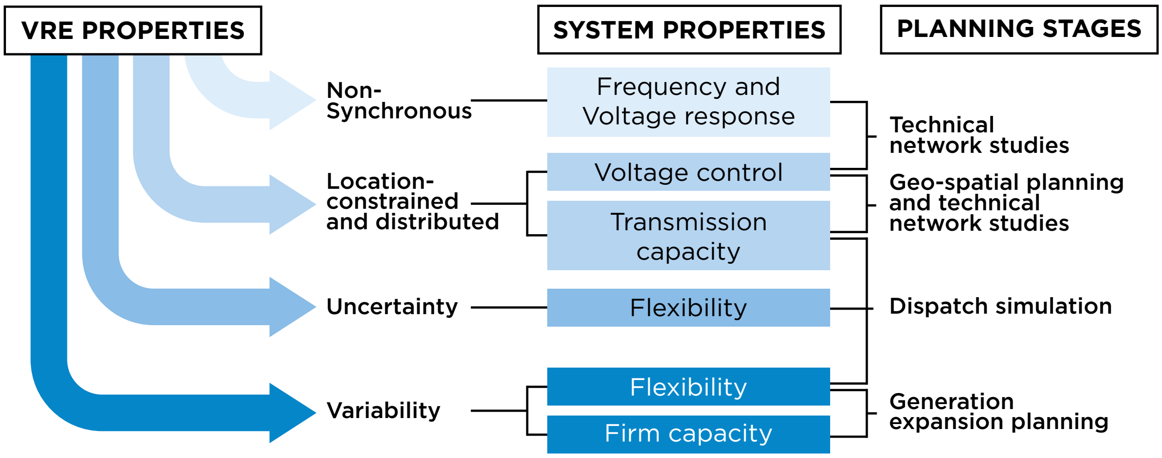



*Source: Adapted from (Wilson and Biewald 2013), with reference to (Hirst 1992)*

For Vietnam, It is important to develop the PDP beyond simply meeting the required demand as determined by the forecasted GDP. Understanding the objectives (for example low tariffs, high reliability, efficient consumption of electricity, green energy sector, etc.) and the goals (portfolio of natural gas resources, diversified renewable energy program, more power flows with neighbors, etc.) should be the first step of the PDP.

As the resource options become more complex with consumers involved in deciding how to best serve their own demand requirements or even participate in the power market with demand response options, planners have to learn to model, without bias, supply-side and demand-side resources to make sure the best economic, environmental and social program in put in place. Vietnam will have to transition its long-term planning from the existing model(s) to models that, in fact, proper model resources on equal footing. Figure 4 illustrates how power system planning models would be changed when dealing with VRE resources.

***Figure 4: Possible changes in power system planning models when power system properties change due to variable renewable energy***




*Source: From (IRENA 2017)*

Figure 5 outlines the key elements for IRP – along with other planning mechanisms involving government decision-making. It is necessary to emphasize that IRP can be resource-intensive, time-consuming, and require specialized expertise in economics, power system modelling and other disciplines.

***Figure 5: Key elements of Integrated Resource Planning***

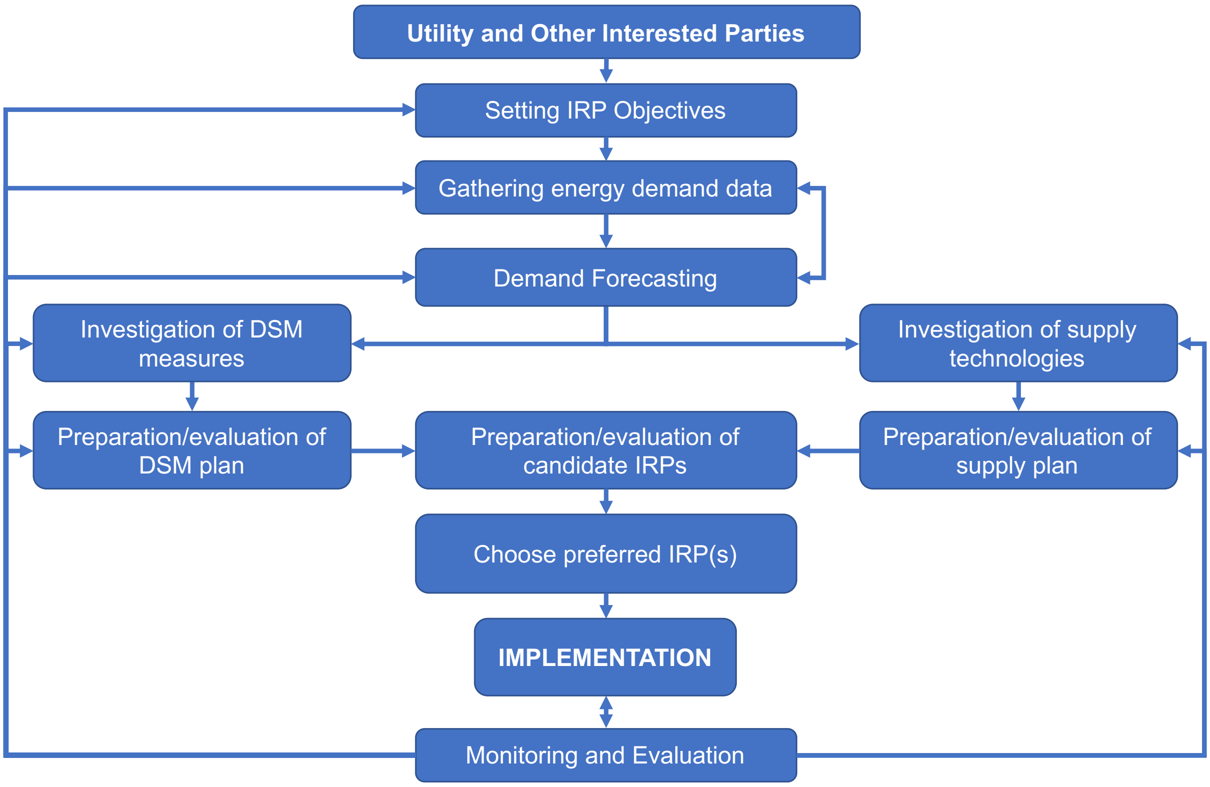

*Source: Adapted from (IRENA 2018)*

However, IRP enables planners and decision makers to satisfy long-term power demands with the most affordable resource portfolio, while satisfying all legal requirements and public policy objectives, with due consideration of risks and uncertainties. It is also possible for planners to employ the basic IRP framework while tailoring the level of sophistication and rigor used in each element of the planning process to the capabilities and resources available (IRENA 2018).

The cost of producing a long-term power plan will probably increase. The cost of developing a robust and sound plan is a small issue compared to the cost of developing a plan that is low cost to develop yet provides an inappropriate investment plan that could cost Vietnam and its retail electricity customers many times the cost to develop the plan.

Figure 6 describes a typical IRP process for electric systems, with discussion of various elements and steps to follow.

***Figure 6: The Integrated Resource Planning process***




*Source: Adapted from (Nichols and Hippel 2000)*

### 2.1.2. LEAST COST PLANNING

**Least Cost Planning: Produces a portfolio of resources that will produce the least cost plan**

Least-cost planning is a process by which electric utilities or state management agencies on power sector evaluate the costs, benefits, and risks of different resources for meeting electric power demand (including traditional power plants and energy efficiency) to arrive at the mix of resources that will meet future demand at the lowest cost while still providing reliable electric service.

IRP-based least-cost planning is transforming the planning process traditionally used in the electric utility industry. As compared to the traditional planning process, least-cost planning broadens the participation by multiple parties and widens the range of the planning options that are assessed. Its integrative nature opens consideration of multiple planning objectives (such as social, environmental, and economic objectives) in evaluating demand-side and supply-side options.

**Error! Reference source not found.** compares the key planning factors considered in the conventional “least cost generation expansion planning” against the IRP-based least cost planning. The conventional approach typically arrives at a power development plan through a process that comprises load forecasting, developing assumptions about investment and operations costs of a limited list of options, and a computerized optimization that chooses among the limited options considered.

***Table 1: Factors considered in conventional "least cost generation expansion" planning vs. IRP-based least cost planning***

| | Conventional "Least-cost generation expansion planning" | IRP-based |
|---|---|---|
| Bottom-up load forecasting | No | Yes |
| Generation costs | Yes | Yes |
| Demand-side management options and costs | No | Yes |
| Transmission and distribution costs | No (typically added after optimization) | Yes |
| Risks of fuel price volatility, drought, carbon taxes, etc. | Little or no consideration | Yes |
| Social and environmental "externality" costs | No | Yes |
| Public involvement throughout process | No | Yes |
| Scenario and sensitivity analysis to ensure "least-cost" under different cost or demand assumptions | Little or no consideration | Yes |

*Source: Adapted from (Greacen, et al. 2013)*

PDP planners will need to understand/collect the underlying electricity consumption equipment's age, efficiency, consumption patterns, saturation rates and the forecasted efficiency of future replacement equipment. In addition, national policy initiates that promote or mandate efficiency of energy consuming equipment must be properly modeled by the planners.

In master power development plan practice, unprecedented uncertainty in the electricity sector makes it difficult to estimate the cost or likely range of costs for new capital investments. Different assumptions about the future can make an investment that is least cost in one future or scenario high cost (relative to other investments) in another. In many states, utility commissions use a least-cost framework to evaluate different investment options, but determining what is least cost is difficult and can depend on the range of potential futures that utilities and regulators consider. Also, estimates of the long-term cost of investment alternatives in the electricity sector are based on assumptions about multiple variables (fuel cost, load, wholesale market prices, cost of construction and operations, regulations, financing costs and so on) that are volatile and difficult to predict. Most of these estimates are based on calculations of the costs' net present value assuming a single, known future (or scenario) for all variables. Estimating future costs in the electricity sector is further complicated by the long financing life (20-plus years) and lead times of capital investment. Moreover, the further into the future forecasts of variables, like fuel prices, are made, the more likely they are to be incorrect.

Getting more perspectives on future trends would help the PDP planners as they develop the options and future scenarios to evaluate the options. The process for obtaining stakeholder perspectives can be through public meetings, private meetings, social media and especially through working groups that can support the planners through the planning process.

### Scenario Analysis

To account for the uncertainty of key input variables and cost estimates, electric utilities often analyze investment options and portfolios under a range of scenarios. Each scenario represents different assumptions about the future, with varying forecasts for key uncertain variables. Within each scenario, or "bundle of assumptions," each uncertain variable has a single path (or trajectory).[1] With a wide range of potential futures, results tend to vary significantly across scenarios; an investment that is least cost in one scenario is high cost in another. If the least-cost investment option varies across scenarios, utilities and utility commissions must adopt additional criteria to determine which least-cost option is "best." Decision makers can give more weight to individual scenarios they believe are more likely to be realized or look for options that perform well across multiple scenarios. In either case, they need to justify why they are discounting the results for scenarios in which the investment option performs poorly. If the decision maker is risk averse, she or he can pick an option that performs poorly in none of the scenarios, effectively choosing to avoid risk rather than attempting to optimize a decision based on cost.

### Integrating Risk Assessment into Least-Cost Decision Making

Risk assessment provides additional information about a given option's potential for negative outcomes due to uncertainty. It can be combined with cost estimates to aid decision-making when the least-cost strategy is unclear and to indicate the range of possible outcomes.

In a scenario analysis context, the decision maker can examine the range of costs for each investment option across all scenarios, rather than focusing on which option performs best in each scenario. Utility regulators and planners generally look for the "robustness" of results across scenarios. Thinking through the negative outcomes for all investment options across all scenarios and creating a narrative may offer additional insight into the likely range of cost outcomes. However, as described below, any attempt to estimate risk using scenario analysis results is dependent on including a range of scenarios that capture all plausible sources of risk.

Regardless of method, one key to successfully assessing risk is integrating risk measures and metrics with other decision criteria. In an environment in which investments are least cost in one scenario but often higher cost in other scenarios, utilities and utility commissions commonly justify decisions based on fuel diversity or performance robustness, effectively merging these considerations with cost.

Combining risk assessment with cost or expected cost data is effectively the same as including criteria like fuel diversity or performance robustness with cost when making an investment decision—a strategy that works best when deployed systematically. Displaying cost and risk data in the same table or figure helps decision makers understand cost and risk tradeoffs.

Given the long project and financing lifetimes and multiple uncertain input variables of electric utility investments, almost all, if not all, cost projections for decisions about these investments will prove incorrect. This reality, coupled with the fact that the least-cost investment option depends on the scenarios considered, makes investment decision making in the electricity sector tremendously challenging. Risk assessment can help decision makers understand the likely ranges of undesirable outcomes and risks for consumers and utilities. Risk assessment methods are well

[1] Traditional scenario analysis, using a single, known cost path for each uncertain variable, is deterministic, meaning the result of the analysis is constant, despite the uncertain inputs.

established in many sectors of the economy and have been effectively demonstrated in the electricity sector by many integrated resource plans. Introducing a formal risk assessment method into a least-cost planning framework should offer decision makers additional insights and help with difficult investment decisions during this period of significant uncertainty and change in the electricity sector.

For example, the impact of significant price increases for public services including electricity prices can slow down economic growth (GDP) as was seen in several “tiger” economies in the 1990s and 2000s. As Vietnam constructs large energy infrastructure projects, the ability and willingness to pay for electricity at prices that cover these new facilities must be examined. If electricity demand does not increase as forecasted, the electricity prices will increase even more as the small demand must pay for the return of and on committed new capital projects. Examining these risks and building in approaches for a more flexible plan would protect against the economic failures not foreseen by other countries.

### 2.1.3. Least Worse Regret Planning and Stochastic Analysis

**Evolving Least Worse Regret: A portfolio with a range of resources and values that will perform well under a range of future possibilities**

Least Worst Regret (LWR - and sometimes minimax) analysis are often used for decision making whenever it is difficult, or inappropriate, to attach probabilities to possible future scenarios. When deciding on an option, LWR aims to minimize the cost implications of any decision made when there is uncertainty over the future. One benefit of this approach is that it is independent of the probabilities of the various potential future outcomes and therefore it can be used when the probabilities of these outcomes are unknown, providing that the cases considered cover a range of credible outcomes.

LWR essentially determines a compromise between the capacities to secure defined by the most optimistic and pessimistic of the sensitivities modelled. The specification of the boundaries of the set of scenarios and sensitivities to be considered in itself introduces subjectivity into such an analysis. The solution of a LWR analysis is given by the value corresponding to the point of intersection of the regret cost functions for the two extreme sensitivities.

At global scale, this approach has been utilized in some OECD countries, including selected states in America and United Kingdom. Recently, it has been endorsed by UK Department of Business, Energy and Industrial Strategy’s Panel of Technical Experts (BEIS’s PTE) as being the most appropriate way of choosing the recommended derated capacity to secure at auction in operation of UK’s electricity market. It accounts for the cost of securing capacity and the cost of loss of load events (i.e. cost of unserved energy). There was general agreement that the unit costs used in the approach should be supplied by BEIS based on public domain information.

The approach involves considering each potential de-rated capacity choice (i.e. the required level to ensure it meets 3 hours LOLE[2]) derived from a particular outcome (scenario or sensitivity) and assessing the cost of the other potential outcomes under that capacity choice to find the maximum regret cost for that potential choice. To do this, a base cost for that case is calculated as the cost associated with the required level of de-rated capacity. For the other outcome cases assessed against that de-rated capacity choice, the regret cost is defined as the absolute value of the

[2] Loss of Load Expectation. See 2.2.5 for details.

difference between the total cost and the base cost. The maximum regret cost for a potential de-rated capacity level is then calculated as the highest of the regret costs across all cases, i.e. the highest cost difference arising from over or under securing. This process is repeated for each potential de-rated capacity choice to find the minimum of the maximum regret costs over all potential choices derived from all scenarios and sensitivities. The Least Worst Regret option is the potential de-rated capacity level with the minimum of the maximum regret costs. This is the same principle used in National Grid's Network Options Assessment (NOA) to choose between potential transmission network reinforcement options. This approach was also used to assess the volume required for UK's National Grid's Contingency Balancing Reserve in 2014/15, 2015/16 and 2016/17.

To determine the maximum regret cost for a particular case, a view on the unit de-rated capacity cost and unit cost of unserved energy is required to ensure the consistence with the Reliability Standard such as Value of Lost Load for Expected Energy Unserved (EEU) and unit cost of de-rated capacity.

The PDP planners will need to identify and analyze the costs (impacts) related to underdeveloping the electricity sector and the costs related to overdeveloping the costs (impacts). These impacts may include security of supply, tariffs, access to foreign markets and economic development.

## 2.2. DETAILED COMPONENTS IN A TYPICAL POWER DEVELOPMENT PLAN

### 2.2.1. DEFINING OBJECTIVES, PLANNING SCENARIOS, AND SENSITIVITIES

A foundational element of the power development planning or IRP process is scenario definition, which represents a crucial area for input and guidance by stakeholders so that the scenarios reflect questions that are most interesting to the power system. A ***scenario*** is one possible future electric generation system. Scenarios in a power development plan provide the basis for exploring how different options for the future power generation fleet, transmission network, and/or operational practices impact power system reliability, economics, and other objectives such as emissions reduction. Scenarios define system conditions over a specific time horizon, usually referencing a future ***target year***. However, the modeling will also explore pathways that allow the study team to answer questions about near-term, medium-term, and/or long-term challenges and opportunities related to RE deployment.

A ***sensitivity*** refers to an alternative set of assumptions about infrastructure, fuel costs, operational practices, or the availability of a technology option that mitigates concerns that emerge in the analysis of the core scenarios. A sensitivity is applied to one or more scenarios, and the results are reported relative to the scenarios without sensitivities.

Examples of common scenarios and sensitivities in power development plans include:

- Varying levels of demand (high, low, etc.)
- Varying levels of fuel costs (high, low, etc.)
- Varying hydro or climatological conditions (wet, dry, high or low wind or solar, etc.)
- Project delays (delay to a candidate generation plant, delay to a transmission project)
- Alternative projects
- Alternative configurations (technical characteristics) of specific projects
- Varying RE (more or less wind and/or solar generation or capacity, different locations for RE generation)
- Moving specific plants from committed to candidate status, or vice versa
- Alternative operational strategies (e.g., reducing generating unit minimum operating levels)

- Varying levels of energy storage
- Varying levels of EE, DSM, EVs, and DR
- Alternative policy decisions (RPS, emissions limits)
- Different power market structures and rules, different bidding behaviors
- Alternative scenarios for distributed generation (e.g., rooftop solar) deployment
- Provision of varying products by imports (energy, A/S provision)
- Varying levels of reliability (e.g., by varying levels of operating reserve)

Depending on the specifics, a scenario or sensitivity may require the corresponding analysis during the demand forecasting, capacity expansion, transmission expansion, or operational modeling stages. For example, a high demand scenario might require analysis to start at the demand forecasting stage and proceed through all the stages. However, if the premise of the scenario is the system was built out for reference demand, but the demand is higher in a particular year, some adjustments will need to be made to the demand forecast, and then the analysis would skip to the operations model to determine how the system performs with the higher than anticipated demand. A scenario with an adjustment to RE generation (e.g., type and location of solar and wind power plants) would start with corresponding changes to the capacity expansion model. A delay to a transmission project would use the existing demand forecast(s) and would start at the transmission stage.

By comparing the results between proper scenarios, the impacts to the system in terms of operations, utilization, costs, reliability, etc. can be quantified. For example, the benefits to the system for having flexible imports as compared to a constant import level, can be quantified. This information is essential to support actual PPA negotiations for the import.

The PDP planners must decide what scenarios may be relevant to explore. Given that data may not be available in the near term, laying out the scenarios that the planners would like to examine will provide insights on the data that needs to be collected in the next 2-3 years for a more robust PDP to be performed later. If the same planning models are used, a seemingly endless number of input decks need to be developed to examine the scenarios. With modern planning models, scenarios and sensitivities to those scenarios can be examined simultaneously.

### 2.2.2. Power Demand Forecasting

As shown in Figures 1, 2, and 3, **demand forecasting lays the foundation for the IRP process and determines how much, what type, where, and when generation and transmission resources are needed**. In many power systems, **demand is also treated as a resource**, able to participate (e.g., through demand response programs) in the provision of grid services traditionally provided by conventional generation and/or storage resources. Demand also plays an important role in integrating variable renewable energy resources to the power system, depending on the extent to which the shape of demand (i.e., the load profile) aligns with solar and wind energy resource availability. Further, demand response programs can provide a relatively low-cost source of power system flexibility that can aid the integration of variable renewable energy (Cochran, et al. 2014).

A robust demand forecast (possibly with multiple scenarios) is an essential input to capacity expansion and operational modeling, as discussed below. Key uncertainties to resolve in the demand forecasting process include the rate of demand growth; the proportion of future demand across different sectors; and the demand profile, which depends upon weather and end uses, including changes in the utilization of technologies such as air conditioning, electric vehicles, and energy efficiency mechanisms. For the purposes of developing an IRP, the key outputs of best practice demand forecasting methodologies include one or more future scenarios for the following:

- Sector-specific (i.e., residential, commercial, industrial, transportation, agriculture) load profiles, disaggregated to hourly or sub-hourly timesteps and allocated to each node in the modeled transmission system; and
- Load flexibility potential (e.g., scenarios for demand response programs and EV charging).

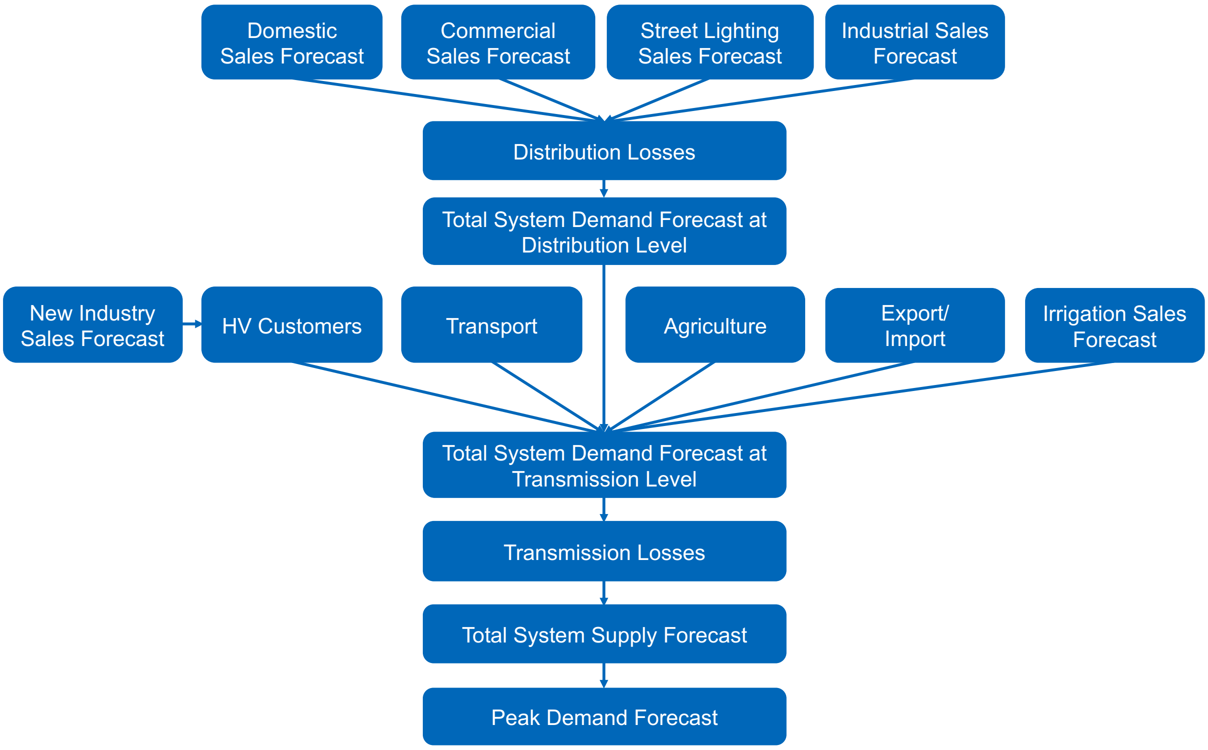
Methodologies for demand projections range from simple estimates (for example, based on projections of gross domestic product) to more sophisticated economic and statistical models that analyze potential growth in demand. A good practice is to combine top-down and bottom-up demand forecasting. Top-down forecasts scale historical demand profiles based on projected changes in population, weather, macroeconomic factors, etc. Bottom-up forecasts capture changes in load that result from rapid technology and/or policy changes. Bottom-up analysis can include, for example, building-level load profiles, including potential new energy efficiency and demand-side flexibility.

Key topics to consider and incorporate into the demand forecasting process include:

- **EE and DSM potential**. Common practice in evaluating opportunities for EE and DSM is to create baseline, sector or sub-sector specific scenarios based on data from a historic year, and then to modify each baseline based on load growth and technology adoption scenarios specific to the residential building, commercial building, industrial loads, and other sectors.
- **EV adoption**. In some countries, plug-in EVs are emerging as a potentially major additional electrical load as well as a source of flexibility (e.g., EV participation in demand response). Because EV adoption is in its early stages globally, and because its impact on the power system depends in large part on consumer preferences (e.g., when and where to charge), best practices related to modeling EV adoption in demand forecasting are still emerging. As one methodological example, for U.S. studies, NREL has developed the Electric Vehicle Infrastructure Projection Tool to estimate EV charging requirements at a high spatial and temporal resolution based on vehicle and infrastructure attributes, local travel data, and EV sales projections (Wood, et al. 2017).
- **DR potential.** DR potential can be estimated as part of sector-specific analyses (e.g., opportunities specific to buildings or EVs participating in demand response). DR analyses evaluate the potential for load to provide three broad categories of value to improve power system flexibility: energy services, operating reserves, and capacity value**.** DR resources provide *energy services* when they offset system operating costs by reducing reliance on expensive generators, for example, to meet peak demand. DR resources also can provide *operating reserves* to correct short-term system imbalances between supply and demand, such as from unplanned generator outages or from uncertainty in forecasts for load and variable renewable energy generation. Meeting these reserve requirements with DR can offset the cost of procuring spinning reserves from more expensive conventional generators. Finally, DR can provide *capacity value* and improve the ability of the system to meet reliability standards by reducing the need for conventional generation and offsetting investments in additional capacity, particularly peaking capacity. For the purposes of IRP development, estimating DR potential involves evaluating which sectors and end uses can participate in DR; the type of service or response they can provide; the potential magnitude of the response; the speed of the response; and the length of the response.

An example of the various components of demand forecasting, which is the basis for the demand forecast for a few of the international examples, is shown below.

*Figure 7: Components and Build Up of the Power Demand Forecast*




*Source: Compiled by V-LEEP team*

As with the earlier figure, the above is meant to give a general idea of the buildup. There may be several variations and nuances as the actual work is done. For example, the treatment of DR may cause some of the demand to be modeled on the generation side. Within agriculture, there will likely be (bio, bagasse) generation, which may be modeled on the generation side, but whose assumptions will need to be closely coordinated with the corresponding aspects of demand.

Tools based on Excel, such as Simple-E, along with the native tools in models such as PLEXOS or the ABB Suite are available to assist with the forecasting work.

The forecasting effort should include a backcast effort which can be used for validation purposes. A best practice backcast covers, at a minimum, a 12-month period, and possibly longer if there were any unusual events during the backcast period (e.g., out of the ordinary outages caused by storms, unusual consumption due to suppressed economic activity). The backcast should be done for one typical year.

The PDP planners should rely upon regional studies conducted to collect and analyze end-use demand components. The data required for the demand forecasting analysis and developing the characteristics of demand-side resources should therefore be identified in 2019 and initial data should be collected through various methods including customer surveys and analyzing import statistics. As suggested before, demand data could be acquired from regional planning exercises as proxies for the country's data.

### 2.2.3. Long-term (LT) Capacity Expansion Planning

**Generation expansion planning**

Capacity expansion analysis identifies where, when, how much, and what types of resources (generation, demand, storage, imports/exports, and/or transmission) would achieve reliable electricity at least cost, taking into consideration factors such as physical constraints, policies and requirements (including RE targets and emissions targets), technological advancement, fuel prices, and demand projections. Capacity expansion analysis is an inherent part of IRP, and often uses a capacity expansion model. This type of model determines the least-cost technology mix by comparing the life-cycle cost of different options and their ability to provide various grid services, including firm capacity, energy, spinning reserves, regulation reserves, and flexibility reserves. Capacity expansion models are capable of analyzing both operational and investment (including capital cost) considerations over a long time horizon and can inform understanding of how the power system might evolve over time.

Most capacity expansion models focus on the bulk power system.[3] Key inputs to the long-term capacity expansion model include scenarios, demand forecasts, capital costs of generation technologies, and fuel price projections, among others.

Historically, capacity expansion models were not designed to capture the unique temporal, stochastic, and spatial characteristics of variable renewable energy (wind and solar) energy resources. However, power systems pursuing high levels of variable renewable energy are gaining experience in this area, and good practices for including renewable energy resources in capacity expansion models have emerged, e.g. IRENA's guidance on long-term modeling and tools for planning for higher levels of renewable energy (IRENA 2017). To illustrate, best-in-class models use as inputs high spatial resolution data that characterize renewable energy resource availability across space and time. They also use up-to-date assumptions regarding technology cost and performance projections for variable renewable energy technologies, including the increasing ability of renewable energy resources to contribute a variety of grid services beyond energy generation.

Unlike operational models, capacity expansion models do not typically simulate system dispatch in detail, but instead use reduced-form dispatch models, for example, simulating a representative day or week (Diakov, et al. 2015). The long-term capacity expansion model will therefore provide an initial long term plan, for the base case and for scenarios as appropriate. However, these results should only be thought of as preliminary, as they must be evaluated through the transmission analysis and operations (short term) modeling. Without the latter, the analysis, and the resulting answers, are incomplete. For example, in the long-term analysis, aspects such as the detailed nodal representation of the transmission system, cascaded hydro, variable renewable energy generation, power market, reserves, unit commitment, start characteristics, may be simplified or ignored. In all the international examples in the Appendix, the complete analysis was performed before results were finalized.

Vietnam has used a supply screening process to determine the long-term levelized price for new generating plants. The next step is to determine how these various capacity resources will contribute to capacity requirements, and Vietnam will need to select a model that can model the

[3] An emerging good practice is to also include capacity expansion within the distribution system, for example, as electricity end users adopt rooftop solar photovoltaic technologies. Modeling adoption of distributed generation resources at the distribution level requires a different model than that used for bulk power system capacity expansion modeling (for example, NREL uses its *Distributed Generation Market Demand* model for studies in the U.S. and elsewhere; see https://www.nrel.gov/analysis/dgen/ for more information.) This is because utility-side investment decisions are usually based on least-cost investment decisions, subject to meeting load, reliability requirements, transmission constraints, and environmental and policy regulations. On the other hand, rooftop solar PV investment decisions, are typically independent of these considerations. Adoption decisions are still often cost-driven, but they typically do not consider the impacts of the rooftop system beyond one's own home or office building. Also, costs for the rooftop systems are typically compared against retail rates, which are considerably higher than the wholesale rates used for utility-side decisions.

various system operating conditions so that the best balance of capacity can be determined. With demand-side resources also able to contribute to peak demand requirements and other operating services, the selected model must be able to take these types of resources into consideration.

#### Transmission expansion planning

Scenarios for long-term transmission network expansion are both an input to and output of the power development planning process. While some capacity expansion models in use internationally are capable of co-optimizing generation and transmission capacity expansion, many power systems identify needs for new and/or upgraded transmission and distribution infrastructure by iterating among capacity expansion, operational, and network simulations. The starting point for transmission expansion planning is an accurate representation of today's grid, along with known plans for future years. As discussed below, operational and power flow models can then be used to validate the scenarios and confirm the network performs satisfactorily and meets reliability criteria. If the latter is not true, adjustments to the network will be made to ensure reliable performance, and the process of capacity expansion, operational, and network modeling will be repeated with these adjustments. These adjustments will be based on the study results, as well as the reliability criteria.

Vietnam currently uses PSS/E for transmission modeling. This is an internationally used software that has strong modeling capabilities. For the interim or longer, Vietnam should continue to use PSS/E. With increased options and scenarios, additional iterations between generation plans and transmission plans should be realized.

### 2.2.4. Operations Modeling

#### Description of operational modeling (short term modeling)

While the capacity expansion modelling is the core element of IRP analysis, there are inherent limitations in capacity expansion modeling that require additional steps. The operational model (also known as a production cost or dispatch model) includes additional detail that cannot be accommodated in the long-term model, due to computing resources (time and memory). Examples will likely include the full nodal/transmission model, cascaded hydro, solar and wind variability, details of the power market, fuel delivery (incl. gas pipeline) constraints, and hourly/sub-hourly analysis. The specifics will be determined based on the choice of model(s) and by performing some benchmarking work.

The objective of operational modeling is to optimize the scheduling and dispatch of generation to meet expected demand in the most cost-effective manner, within the context of constraints (e.g., RE resource and transmission availability, operational practices). The operations model, by including the maximum amount of detail, will test the feasibility of the plans developed by the long-term model, and refine the economics of each of the plans. The system configuration —including the types, capacities, and locations of transmission and RE and conventional generation—is derived from long-term capacity expansion model. The operational model then performs a security constrained unit commitment and economic dispatch to simulate hourly or sub-hourly operation of the grid to measure operational costs and validate the load/balance match, check for reserve violations and measure basic transmission adequacy (typically using a DC approximation of the transmission network). The model essentially mimics the System and Market Operator (SMO), by committing and dispatching the generation system through the minutes and hours of the day, week, month and year, and doing so economically while attempting to meet all the reliability requirements of the power system, hydrological constraints, power market rules and behaviors, etc.

The goal of including an operational modeling step in power development planning is to test the operational impacts of capacity expansion scenarios and provide feedback to help fine-tune capacity expansion analyses. Therefore, it is primarily used as a validation step, although many of the results are used directly in the final results. It can also serve as the primary tool for evaluating the impacts of integrating variable renewable energy to the power system and evaluating options to improve power system flexibility through a variety of mechanisms. Results reported include RE curtailment levels, generator ramping requirements, plant load factors, reserve violations, emissions, fuel consumption, transmission constraints, and operational costs associated with different RE scenarios and flexibility options.

Issues will almost certainly arise in the operations model, which will result in adjustments to the capacity expansion plan. Depending on the issues, the transmission analysis and/or the long-term modeling steps will be adjusted and rerun to develop revised plans which would again be evaluated in the operations model. Thus, the process is very likely an iterative one, involving more details than can be depicted in Figure 3.

The operational modeling step is also used to identify "periods of interest" (e.g., high RE/low load, low RE/high load) that may require further stability testing via a power flow study.

The nodal capabilities of commercial, industry-standard production cost models allow for a very detailed dispatch analysis to be performed across time (e.g., across all hours of a year), which is something that cannot, practically, be either in a capacity expansion model or in a load flow model. However, load flow models are required to perform the voltage, short circuit and stability studies, and to potentially examine power flow or contingency issues that are not captured in the production cost nodal analysis, as discussed below.

The use of a detailed operations model is needed as Vietnam progresses to a significant amount of renewable energy and with the introduction of flexible demand-side resources. The first step is to understand what input data is required of detailed operations models, collect and analyze the data and then select the best model for Vietnam.

## Examples of operational modeling

Several of the examples in the Appendix demonstrate the results of the operation (short term) model, together with the rest of the PDP methodology (demand forecast, transmission network analysis, long term model). All of these have elements that are expected to be similar to considerations that will arise during the PDP8 study in Vietnam.

- The Southern California Transmission Study demonstrates the evaluation of different transmission configurations, transmission outages, transmission utilization, and renewable resources curtailments. This was done with detailed representation of other aspects of the system such as reserves, power markets and cascaded hydro. Similar considerations are applicable for Vietnam.
- The Transmission Congestion Impacts & Curtailment Risk example from the Western USA demonstrates the evaluation of wind generation, its value, power market bidding behaviors, and the potential impacts of congestion and curtailment. This was done with detailed representation of other aspects of the system such as reserves and cascaded hydro. As Vietnam is moving to a competitive market, new resources will be placed at many different locations that may not only create physical congestion but economic congestion as well. Analyzing future system conditions with new generating plants will guide not only the need for new transmission but also policy related to promoting generation near to the demand.

- The Market Revenue for a New Combined Cycle Plant in the Western USA demonstrates the ability to evaluate the operations of a traditional thermal resource, power market bidding behavior and transmission congestion. It also demonstrates the ability to perform a backcast/benchmark. The need for gas-fired generation to complement additional renewable energy resources is a common theme in power systems and should be thoroughly examined by the planners.
- The example regarding Unit Commitment – why are GTs running more than expected, the issues that are correctly captured in this example would have been missed if only a long-term approach had been used. The feasibility of the long-term solution would not have been tested, and infeasibilities, such as these, missed. The use of a typical week, sample week, or similar approach, would have missed these issues. Short and long-term models have their contribution to the PDP, which is already the practice in Vietnam.
- The Expansion Plan – Coal Example, similar to the previous example, this would have been missed if only a long term, typical week, simplified/lacking unit commitment & dispatch approach had been utilized (such as the approach used in PDP7 and RPDP7). Such issues will undoubtedly arise in PDP8 for Vietnam if no change in the approach. A more detailed operations model is needed in Vietnam to understand unit commitment issues.
- Expansion Plan – Generation Mix, also demonstrates the importance of the operations (short term) model in evaluating the feasibility of solutions (expansion plans) proposed from a long-term model.
- Valuation of Solar Resources – demonstrates the type of detailed results that can be picked up in an approach using today's tools and methods, as proposed here. In this example, due to a variety of factors, as discussed in the Appendix, the value of specific solar projects, to the system, are quantified. Such results are essential to development of a reliable expansion (least cost) plan. Without it, the correct amounts and locations of solar for the optimal expansion plan could not be correctly determined. The example also shows that is naïve to discuss a system wide price for solar, wind, or other generation, as location specific issues can result in a significant variation in the price/value. Detailed solar resources for Vietnam will enable these plants to be properly modeled. The selection of an operations model must include the requirement that the model can handle solar specific operating issues.
- Imports – Value of Flexibility demonstrates the value to a real power system, associated with flexible, as compared to inflexible, imports. Again, this can be correctly evaluated and quantified using the methodology proposed here and would not be captured using the methodology used in RPDP7. Such analysis will be essential to determining the feasible, optimal expansion plan. Note that variants of this may treat reserves in different ways, which will require the detailed representation and co-optimization of reserves, which again can be done using the proposed methodology and not the previous one.
- Evaluation of Different Technologies – though this example deals with alternative technical configurations of geothermal resources which may not be an issue in Vietnam, the evaluation of different technical configurations of generation (and transmission) projects will certainly be part of the PDP8 analysis. Again, the proposed methodology can capture this, and the previous one cannot.
- Evaluation of DR/DSM – DR/DSM are examples of demand side options which can provide significant benefit to the system. The benefits and costs need to be correctly analyzed and quantified to evaluate these, compare them to other options, and determine their role in the optimal expansion plan. The technical and location specific issues can only be captured using the proposed methodology and tools, as is demonstrated in this actual analysis.

- Delay in retirement, new generation, project delay – evaluations of timing of new projects, delays in new projects, retirements/refurbishments of existing facilities and delays in the retirements/refurbishments will all be part of the PDP analysis. To capture the impacts these have on the system (energy, reserves, locational specific challenges, etc.), and hence the optimal expansion plan, the proposed methodology must be used. Vietnam has seen several delays in new resources are a result of obtaining government approvals by the developers and the delays or failures in obtaining financing for the new resources.
- VRE Example & Considerations – in this example from a PDP type of study, varying amounts of solar and wind generation were being considered for the optimal expansion plan. Using a methodology similar to the one proposed here, the challenges for the rest of the system to "firm" the solar and wind resources were identified in the intra-day (hourly and sub-hourly) demands on the rest of the system (e.g., ramping of other resources such as hydro). Some of the resources were operating just inside of their technical limits (e.g., cavitation, reservoir limits, ramp limits). These aspects would not have been identified using a long term, typical week, simplified hydro, simplified unit commitment & dispatch approaches. The current process is generally fine but there is a need for a more detailed operations model.
- Solar Curtailment – this example demonstrates the importance of hourly/sub-hourly analysis together with a nodal (detailed transmission) representation of the transmission system. The fact that there would be curtailment, and quantification of the amount of curtailment is essential to PDP type of analysis and would not have been identified, much less quantified with the methodology used in RPDP7.
- Coal Configuration evaluation – this example, also from a national PDP exercise, evaluates two different configurations for a sizeable coal plant. Using the methodology proposed for PDP8, the operational issues and benefits of the alternatives were quantified, demonstrating a substantial savings in operating costs, which can be factored in with the capital and finance costs of the alternatives to determine which is the best option.
- Operating Reserve Example – in order to ensure reliable operations, operating reserves must be maintained. In this actual national PDP example, the timing of a new coal plant is evaluated, including its impacts on reserves. The interaction between specific hydro, geothermal and coal plants, along with their associated constraints (e.g., reservoirs, cascades, ramping, transmission) were evaluated. This was only possible due to the ability of the modeling tools to represent and co-optimize reserves, along with the other aspects of the system.
- Variability analysis for Reserve Requirements – in this example from a national PDP study, a variability analysis is performed to determine the operating reserve requirements due to varying amounts of demand and renewable generation. This is a necessary calculation that must be done as an input to the long term and operations modeling. This is a methodology/approach that is needed for Vietnam to ensure smooth integration of renewable energy resources.
- Renewable and RPS studies for Hawaii, India, Philippines and Thailand demonstrate the need for using a methodology and tools as proposed here, in order to properly identify and quantify potential challenges and benefits associated with increasing amounts of RE generation. As previously mentioned, the PDP analysis must include operations (short term) modeling, which includes operating reserves, hourly/sub-hourly granularity, nodal representation of the transmission system, unit commitment and dispatch, detailed hydro and thermal representations, etc.

### 2.2.5. Resource Adequacy Assessment

Resource adequacy analysis is used to ensure a power development plan meets system reliability targets (Table 2). These reliability targets are based on the capacity value (also known as capacity credit), of individual resources, or their contribution to reliably meeting demand. Resource adequacy metrics are included in some long-term and/or operational models. Alternatively, this type of analysis can be conducted exogenously.

***Table 2: Power system reliability: areas of focus for transition planning***

| | Generation | Networks |
|---|---|---|
| **Adequacy** | Firm capacity | Transmission capacity |
| **Security of operation** | Flexibility | Voltage control capability |
| | Stability (frequency and voltage response) | |

*Source: From (IRENA 2017)*

Determining overall system adequacy requires comparing the available capacity to expected system demand at some future date. The metrics most commonly used to assess system adequacy use probabilistic methods to determine loss of load probability (LOLP) in any given time period. This metric is then used to generate overall loss of load expectation (LOLE) (a measurement of the expected days in a year that could face a generation shortfall) or the loss of load hours (LOLH) (expected number of hours in a year with insufficient generation).

Modeling capacity adequacy is particularly important when evaluating a high-RE resource mix. Due to variability and uncertainty, RE resources typically have a lower capacity value than conventional generators. Several methods exist for calculating the capacity value of wind and solar, including detailed reliability-based metrics such as effective load carrying capacity (ELCC) (Denholm and Katz 2015). Capacity value calculations require high temporal and spatial resolution RE resource data for multiple historic years. If high-resolution wind or solar resource datasets are not available, commercially available modeled datasets (lower resolution and lower cost) may be used for the purposes of pre-screening (Parsons, et al. 2015).

### 2.2.6. Load Flow and Stability Analyses

Network analyses expand on the operational analysis to provide a more detailed examination of transmission (and, depending on scope, distribution) system reliability. Transmission network analyses can include steady-state analyses (e.g., load flow, contingency analysis, short-circuit level calculations, harmonic issues) and dynamic analyses (e.g., transient stability, small-signal stability, frequency stability, and voltage stability) (IEA Wind 2018). Among other reliability considerations, they test the ability of a power system to respond to a real-time disturbance such as an unplanned generator or transmission line outage (contingency events). Load flow studies model real and reactive power flow, fault tolerance, and contingency response over very short timeframes that correspond to periods of system stress. Evaluation of costs and economics is not usually a component of this type of reliability analysis.

Since load flow models focus at very small timescales (usually the few seconds during and following a disturbance), these studies rely on the results of operational models to identify periods of potential system stress (e.g., high wind/low load) to study in more detail. In turn, results from load flow simulations provide feedback to refine the operational and/or capacity expansion models. Load flow and dynamics simulations can expose weaknesses in the system that may need to be addressed by changing scenario assumptions, adding transmission or generation capacity, and/or adjusting grid operations.

Several industry-accepted, commercially-available load flow models are available. Many power system operators already use these types of models to inform power system planning. Some evolution in traditional methodologies may be needed for systems considering high shares of variable renewable energy. For example, steady-state load flow analyses traditionally have been conducted for peak load and low load "snapshots." The number of load flow cases may need to be expanded to include critical situations related to solar and wind energy generation, such as times when generation from these non-synchronous resources is high and demand is low. Similarly, the cases considered in dynamic analyses may need to be expanded to include a variety of periods of system stress related to solar and wind generation, and these analyses will rely upon appropriate solar PV and wind turbine models.

Network analyses also can be conducted for the distribution system and are becoming a good practice for power systems considering significant levels of variable generation (e.g., rooftop solar PV) at the distribution level. Distribution system analyses can include estimating the hosting capacity of individual feeders to determine the amount of distributed solar PV that can be deployed on the distribution network. They can also estimate costs for feeder upgrades in locations where distributed generation deployments may exceed hosting capacity. Separate models are used for each of these types of studies.

If the load flow and dynamic stability analyses produce results that do not meet reliability metrics, it may be necessary to iterate with the long-term capacity expansion and operational model to add new or upgraded transmission and distribution infrastructure.

## 2.3. GENERIC DATA REQUIREMENTS

High quality data underlie a robust power development plan. In many cases, data collection can be a time-intensive process and may need to begin well in advance of the modeling activities associated with developing the plan. With the impending start of the PDP-8 study, it may be difficult or impossible to acquire all the information needed to complete a comprehensive IRP for Vietnam. Some consideration by the MOIT to produce an interim PDP 8 until the minimum data required to complete the first IRP for Vietnam is collected and analyzed.

The sections below provide more detailed descriptions and lists of input data for power development planning. Table 3 shows a general overview of the data needs for each type of analytical component of the power development planning process.

***Table 3. General data needs for capacity expansion, operational, and transmission network analyses***

| Type of analysis/Data category | Capacity expansion | Operational | Transmission network |
|---|---|---|---|
| **Electricity demand** | Projected annual, seasonal, and peak electricity demand | Historic demand time-series data that are time-synchronous with RE resource data and disaggregated by node (if available) or region; projected changes to electricity demand magnitude and profile; archive load forecast and forecast error (optional) | Historic demand time-series data that are time-synchronous with RE resource data and disaggregated by node (if available) or region; projected changes to electricity demand |

| Type of analysis/Data category | Capacity expansion | Operational | Transmission network |
|---|---|---|---|
| **Generation** | Aggregated fleet-level generator characteristics (conventional and RE) | Unit-level generator characteristics (conventional and RE) | Unit-level generator characteristics (conventional and RE), including dynamic characteristics for dynamic stability studies |
| **Transmission network topology** | Inter-region transmission flow capacity | Locations and electrical characteristics of substations, transformers, lines, and interfaces | Detailed electrical characteristics of all substations, lines and interfaces |
| **RE resource data** | Average or typical meteorological year (TMY)[4] (monthly or more frequent time series) | Operational time-series for full modeling horizon (e.g., one year of daily, hourly, or sub-hourly solar and wind resource data that are time-synchronous with electricity demand data); archive forecast and forecast error (optional) | Operational time-series for full modeling horizon (e.g., minute or sub-minute data that are time-synchronous with electricity demand data) |
| **Costs** | Capital costs of generation and transmission resources; fuel price projections; emissions costs; operations and maintenance costs | Fuel prices; operations and maintenance costs; emissions costs | N/A |
| **Geospatial data layers** | Land cover, protected areas, slope, and other characteristics that can be used to screen sites for potential solar and wind power plant development | | |

*Source: NREL*

### 2.3.1. DEMAND

Extensive data are needed for load forecasts. SCADA systems and advanced meters are providing data on loads, and increasingly, on net loads, at finer temporal and spatial resolution. Input data for the demand forecasting step will include:

- Historical load data, at a granular level in terms of time (sub-hourly) and at the nodal level
- Sales data (historical and forecast) at multiple points in the system (generator step-up-transformer, at the interface to distribution, and at the customer meter)
- Historical and forecasts for losses (at various levels in the system)
- Station services load for the generating stations
- Historical and forecast import/export at an hourly level
- Socio-economic and demographic data and associated forecasts
- Breakdowns of the previous by customer type (residential, commercial and industrial) and by sector

[4] TMY data typify conditions at a specific location over a long period of time, such as 30 years. TMY datasets are not averages; they are created by force-sampling values from the multi-year dataset for each period (for instance, in a monthly TMY dataset, January may be sampled from 2003, while March may be sampled from 2009). TMY data represent typical patterns (such as seasonality) over a long period and help smooth the impacts of unusual conditions such as drought or El Niño.

- Information and forecasts for existing and future EE programs
- Historical and forecasts for nonconforming load (industrial parks, flagship projects, factors, ports, mines, agriculture, street lighting, electric trains, etc.), by region and sub-hourly, if available
- EV project peak and energy consumption
- If detailed historical or forecasts are unavailable for nonconforming load, information on how they might change over time (within the day, seasonally, and over the months and years if the customer is increasing usages in phases)
- Information and forecasts on candidate and planned DR/DSM programs and associated details (e.g., location, capacity, costs, trigger levels, rebound)
- Information and forecasts on plans for DG (e.g., rooftop solar) and the associated details (e.g., location, capacity)

### 2.3.2. GENERATION

Detailed technical, cost, timeline, resource, information on existing, committed and candidate generation will need to be collected including:

- Names and locations (point of interconnection) of generators
- Number and capacity of units
- Primary fuel type
- COD dates
- Retirement dates
- Refurbishment, repowering plans
- Maximum and minimum capacities
- Emergency ratings
- Ramp up, ramp down, start up and shut down characteristics and costs
- Startup fuel (type if different than primary), quantity and cost
- Minimum up and down times
- Detailed heat rate characteristics
- Ability to contribute to different reserves
- Stations services load
- Historical planned and forced outage information
- VO&M and Fixed O&M costs
- Capital costs for candidate plants
- PPA and/or bid information[5]
- Fuel price, heat content, fuel limits
- If applicable fuel switching (alternate fuel) information and alternate unit characteristics
- Emissions information
- Esp. for RE units, ability to curtail, historical hourly/sub-hourly generation, and resource information (hourly/sub-hourly for solar and wind)
- As appropriate, gas pipeline network topology and constraints
- Seasonal variations for all the above where applicable
- Hydro specific data:
    - Type of unit (storage, run of river)

[5] Real-world prices are used to fill data gaps. Requests for Information or Requests for Proposal are issued to potential developers in the process of determining expansion needs.

    - Reservoir size and characteristics
    - Cascade details (the setup of the cascade, waterway volumes, rates, rate of change
    - Historical generation, flows, waterway flows, reservoir levels for multiple years
    - Impacts of reservoir levels on generator characteristics (e.g., min, max, efficiency)
    - Cavitation limits and considerations
    - Loss (evaporation and seepage) data
    - Restrictions on release (min, max) as they vary across time due to other uses of water, environmental issues, etc.

Additionally, historical system information should be collected, which include generation, transmission, demand, loss, reserves and outage data on an hourly basis for a couple of years.

### 2.3.3. Transmission

To conduct operational and network modeling, detailed information is needed on the following:

- Latitude and longitude of each bus (node) location
- Buses (nodes) table:
    - Node ID (numeric) - unique identification number of each node
    - Node Name (text) - unique name of each node
    - Zone (text) - zonal assignment of each node
    - Voltage (numeric, kV) - nominal voltage level in kV
    - Load Participation Factor (numeric) - fraction of load assigned to each node. This is a way of disaggregating a system or zonal load profile to individual load profiles for each node
- Transmission Lines table (including transformers):
    - Line Name (text) - unique line name of each transmission line
    - Node From (text: Buses.Node Name) - source connection of transmission line
    - Node To (text: Buses.Node Name) - sink connection of transmission line
    - Max Flow (numeric, MW) - maximum real power flow rating in the forward direction
    - Min Flow (numeric, MW) - minimum real power flow rating in the forward direction (negative value for backward direction flow)
    - Resistance (numeric, p.u.) - the per unit line resistance
    - Reactance (numeric, p.u.) - the per unit line reactance (zero value for DC lines)
    - (Optional) Transmission Line Forced Outage Rate – numeric percentage (%) –all voltage level to be included
- Interface details (interconnections with other countries):
    - Node Name (text: Buses.Node Name) - the node at which the interface is connected
    - Max Export (numeric, MW) - the maximum export as defined from the node to the external system
    - Max Import (numeric, MW) - the maximum import as defined from the external system to the node
    - Flow Profile (numeric, hourly, MW) - historical hourly flow schedule (if it exists)
    - Max Flow Ramp (numeric, MW/min) - maximum ramp rate of dispatchable flow

For many power systems, most of the data listed above are available in existing load flow models for the present and future power system.

### 2.3.4. Renewable Energy Resource and Geospatial Data

For power systems considering higher levels of variable renewable energy, high-resolution renewable energy resource datasets are an important input to the power development planning process and models. These datasets should accurately represent variability of RE generation across both space and time. This is particularly true of variable, site-constrained resources such as solar and wind. Wind and solar resource datasets are often based on meso-scale modeling, complemented by resource measurements that are used to validate the modeled data. At a minimum, operational analyses require one year of RE resource data for locations under consideration for wind or solar generation. Capacity expansion analyses require more than one year of data, or an average or typical meteorological year of data based on multiple years of data. Good practice is to obtain high spatial-resolution datasets (e.g., 10 km grid cells for solar, 1 km grid cells for wind) that provide continuous coverage for the country or power system balancing area enable power system modelers to characterize the spatial variability of solar and wind resources. Similarly, RE resource data with high temporal resolution capture the variability of solar and wind resources across various timescales. For operational analyses, hourly RE resource data are useful for characterizing solar and/or wind availability within operational timeframes. Higher temporal resolution (i.e., sub-hourly) data better capture the variability of wind and solar generation and enable modeling of certain integration impacts and solutions, such as forecasting or changes to reserve requirements. If such data is not available, it can be purchased from a third-party vendor, but Vietnam should also consider a plan for data collection. Over time, the acquired data can be refined through on-the-ground solar and wind resource measurement campaigns. In many countries, the private solar and wind developers and the governments/system operators sign coordination agreements to collect, analyze and share the data.

Operational and power flow analyses should strive to utilize wind and solar datasets that are *time-synchronous* with load data, i.e., the time steps (year, day, hour, etc.) align chronologically among the datasets. Since weather drives both demand and wind and solar generation, time-synchronous data enable power system modelers to understand trends related to the variability and magnitude of both load and variable RE availability.

For many countries, developing high quality wind and solar datasets is a crucial prerequisite to undertaking planning studies for high levels of variable renewable energy. Modeled solar and wind datasets can often be purchased from a vendor. Alternatively, a country or region can develop its own wind and/or solar datasets, for example, using actual measurements or numerical weather prediction (NWP) models. Regardless of source, modeled wind and solar data should be validated and calibrated as much as possible with actual historic meteorological and/or wind and solar energy generation data.

In addition to renewable energy resource data, additional geospatial data are needed to identify which sites are suitable for solar and wind power plant development. The following datasets are commonly used to screen candidate locations for potential projects:

- Protected areas
- Terrain features (e.g., elevation, slope, etc.)
- Land-use and/or land-cover, including rivers, lakes, wetlands and other water bodies
- Major landmarks, and parks
- Urbanized areas / population density
- Other known exclusions, constraints, and stakeholder concerns
- Land ownership
- Soil and vegetation characteristics (for hydro resource assessments)

Once a set of candidate sites for RE development have been identified, generation profiles are created by passing the resource data through a generator model (e.g., for a particular type off solar PV or wind turbine technology). As an example, NREL uses the System Advisor Model (SAM) to determine the hourly or sub-hourly generation output for a given site.

The output of a renewable energy resource assessment is database of available sites for wind and solar power plants, available power capacity at each site (MW), with system performance at site in terms of sub-hourly and annual generation (MWh). Time series power profiles can also include forecasts for use in grid simulations.

Availability of other (non-variable) resources can also be processed to determine the availability of hydro, biomass, and geothermal resources using a variety of GIS data sets that consider resource availability and environmental restrictions.

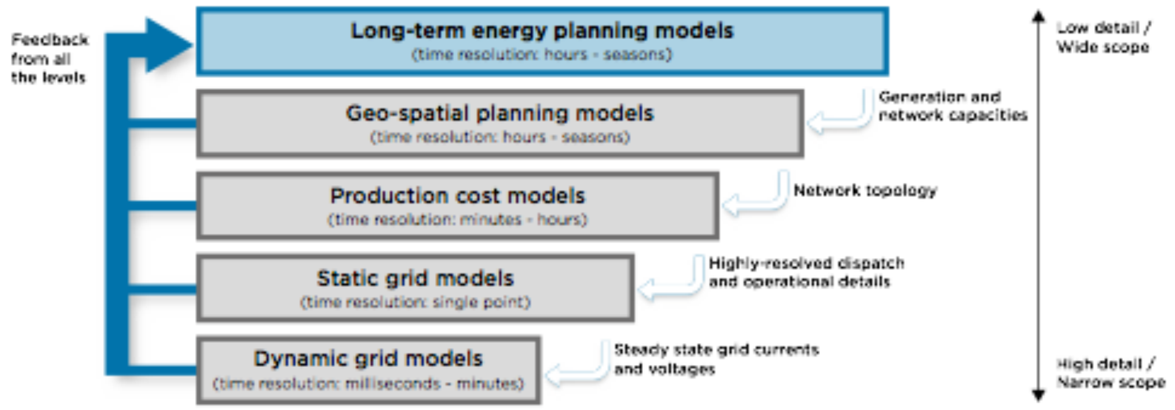
### 2.3.5. OTHER INFORMATION AND COORDINATION

For candidate, and possibly committed, generation and transmission projects, information on dependencies on other infrastructure (e.g., an LNG plant depending on new gas storage and pipeline infrastructure, a wind plant needing a new road) information on the associated costs and timelines should be gathered and included in the timing and costs for the candidate project. Costs and timing associated with issues such as land acquisition, permitting, environmental & social review and mitigations, project financing need to be factored into the PDP input data. Geospatial data characterizing power plant site suitability considerations (e.g., terrain and land use) will also be needed, especially for identifying potential areas to develop solar and wind resources, which are site-specific.

## 2.4. MODELING TOOLS

As described in Figure 8 below, there are different levels of models related to power planning. This section provides an overview of the capabilities of several of major commercial and public domain capacity expansion and production simulation models.

*Figure 8: Tools and analyses for energy system planning with feedback*




*Source: From (IRENA 2017)*

Some advanced capabilities include:

- Detailed modeling of cascade hydro systems on both long term and short-term horizons
- Modeling hydro generation efficiency as a function of head storage level
- Detailed modeling of nodal transmission networks, including full representative of transmission limits in a nodal system and modeling of N-1 contingencies
- Co-optimization of reserves and energy
- Modeling of power markets including power pools

### 2.4.1. ABB E7

The ABB E7 suite combines individual component systems for capacity expansion, reliability, and short term operational planning within a common platform and database. The systems can be procured individually or as part of the E7 integrated platform. For purposes of the PDP, the Capacity Expansion and PROMOD HD components should suffice. These include demand forecasting capabilities.

**Capacity Expansion (NEW Strategist)**

The Capacity Expansion module can produce 20 to 30-year horizon resource investment plans to meet standard long-term reliability requirements, incorporating data such as technology type, fuel, size, location and timing of capital projects. Key features include analysis of renewable energy; integrated resource planning with respect to both supply and demand side options while considering technology improvements, aging assets, and build versus import options; IPP development evaluations for renewable and traditional generation– for resource acquisition to determine the best combination of resources that minimize cost and meet renewable targets.

**Portfolio Optimization**

Portfolio Optimization models detailed unit operating constraints and market conditions to provide a generation schedule for energy and ancillary services, fuel nominations, support the evaluation and pricing of potential short-term transactions, and facilitates the analysis and simulation of deterministic scenarios, while evaluating system LOLE.

Portfolio Optimization does not consider detailed transmission models and limits.

Portfolio Optimization globally optimizes thermal units, combined cycle units, combined heat and power stations, independent and pump storage hydro units, cascaded hydro systems, and renewables in a single solution. The solution also optimizes a combined portfolio of supply resources (traditional generation) and demand response/ distributed generation assets modelled as virtual power plants (VPPs).

Key features:

- Unit commitment and economic dispatch
- Portfolio risk management and hedge analysis
- Fuel management and consumption forecasting
- Decision support for physical trading
- Simulation scenarios
- Post analysis
- ISO/TSO bidding support

**PROMOD HD**

PROMOD HD is a fundamental electric market simulation solution that incorporates details in generating unit operating characteristics, transmission grid topology and constraints, and market system operations to support economic transmission planning.

PROMOD provides nodal locational marginal price (LMP) forecasting and transmission analysis by producing algorithms that align with the decision focus of management.

Key features include:

- LMP forecasting for selected nodes, user-defined hubs, or load-weighted or generator-weighted zones.

- Renewable Energy Curtailment to simulate the effects of intermittent energy schedules from wind and solar projects on transmission congestion and forecast the amount of energy that would be curtailed considering the opportunity costs from incentive policies e.g. production tax credits.
- Economic Transmission Analysis to quickly evaluate the economic benefit/cost, the increase/decrease in hourly/monthly congestion, and the increase/decrease in reliability metrics associated with transmission expansion and outage scheduling.
- Modeling of cascaded hydro systems
- Power market analysis for quantifying the operating risks associated with each facility and developing a detailed forecast of market prices and system operation under various conditions.

### 2.4.2. PLEXOS

PLEXOS is an integrated long term, medium term, and short-term power systems optimization system. PLEXOS uses the same core simulation and optimization system for long, medium and short-term simulations ensuring outcomes are consistent between the levels of models.

Investment planning outcomes (results) from the long-term module are passed automatically mid-term and short-term simulation phases for detailed analysis. The suite includes demand forecasting capabilities.

**LT Plan**

LT Plan solves the capacity expansion problem over a planning horizon in the range of 10 to 30 years, though any horizon is possible. LT Plan appropriately deals with discounting and end-year effects.

The following types of expansion/retirements and features are supported:

- Building new generating plant
- Retiring existing generating plant
- Multi-stage projects
- Building or retiring AC and DC transmission lines
- Multi-stage transmission projects
- Expanding the capacity on existing transmission interfaces
- Taking up new physical generation contracts
- Taking up new physical load contracts
- Developing gas fields and pipelines
- Developing gas storage
- Co-optimizing electric and gas expansion decisions
- Deterministic or stochastic optimization

**MT Plan**

MT Schedule addresses a key challenge in power system modelling, to optimize medium to long term decisions in a computationally efficient manner. Primarily this means managing hydro storages, fuel supply and emission constraints, but there are many other constraints and commercial considerations that need to be addressed over timescales longer than a day or week.

The reason that these medium-term constraints create such a challenge is because they imply that the simulator must optimize decisions spanning weeks, months and years and simultaneously optimize decisions in the short-term (hour or lower) level. In reality decision must be made with respect to intertemporal constraints such as hydro energy balance, fuel constraints, emission limits, or generator technical limits. For example, hydro systems often have storage capability of many weeks, months or even years.

A way is needed for optimizing medium and long-term constraints and commercial decisions while still simulating in relatively small time steps. MT Schedule solves this problem by:

- Reducing the number of simulated periods by combining dispatch intervals in the horizon into 'blocks'
- Optimizing decisions over this reduced chronology
- *Decomposing* medium-term constraints and objectives into a set of equivalent short-term constraints and objectives. The Short-Term Planning module is then applied.

**ST Plan**

ST Schedule is mixed-integer programming (MIP) based chronological optimization. It is distinct from LT Plan and MT Schedule in that it model days of the horizon at full resolution, as dictated by the Horizon Periods per Day setting. At the default setting this means every hour, but the resolution can be customized to any feasible length (e.g. 5-minute intervals).

ST Schedule is designed to emulate the dispatch and pricing of real market-clearing engines, but it provides a wealth of additional functionality to deal with:

- Unit commitment
- Constraint modelling
- Financial/portfolio optimization
- Monte Carlo simulation
- Stochastic optimization

Emulation of real market-clearing engines involves clearing generator offers against forecast load accounting for transmission and other constraints to produce a dispatch and pricing outcome. ST Schedule can do this, but the simulator extends this basic functionality by allowing you to specify fundamental data such as generator start costs and constraints, heat-rate curves, fuel costs, etc. as well as or in addition to market data such as generator offers

Energy Exemplar's exclusive "rolling horizon with hanging branches method" is the next generation in hydro dispatch and storage planning under uncertainty. This next generation solution method is more robust, faster and able to handle many more detailed constraints and integer decision variables than traditional dynamic programming approaches.

Fast and transparent simulations for long-term investment and short-term optimizations are more useful when hydro is co-optimized with other resources. PLEXOS can Integrate complex hydro systems with generation efficiency curves, head storage dependency, waterway flow delays, evaporation and other factors. It seamlessly integrates with the short-term hydro-thermal coordination problem via hydro targets or future cost function decomposition.

Co-optimization models allow you to capture the full value chain from the gas production basin to the electricity load or further to water objects like a desalination plant.

### 2.4.3. BALMOREL

The BALMOREL is a partial equilibrium model, which supports modelling and analysis of the energy sector with emphasis on the electricity and the combined heat and power sectors. BALMOREL is developed, maintained and distributed under open source ideals since 2000. It is highly versatile and may be applied for long range planning as well as shorter time operational analysis. However, the short-range analysis does not include the degree of detail as in other production simulation systems and does not included detailed transmission system analysis.

The model is developed in the GAMS modeling language, and the source code is readily available, thus providing complete documentation of the functionalities. Moreover, the user may modify the model according to specific requirements, making the model suited for any purpose within the focus parts of the energy system. However, there is currently no user interface, which requires users to learn the simulation language to build and execute systems studies. The model is implemented in the GAMS modelling language and a GAMS license is needed to run the model.

There is no user support or training, outside of that provided with international development support. No commercial level support is available.

Approximately 10 versions of the BALMOREL model have been created and Balmorel model has been applied in projects in selected countries in Europe, Asia, North America and Africa.

### 2.4.4. PDPAT

Power Development Planning Assistant Tool (PDPAT) is a power system analysis software developed solely by TEPCO. TEPCO has used and revised PDPAT with experience of its application for the power development plan for more than 30 years. PDPAT is used to analyze power supply capability and system operation cost by daily basis calculation. PDPAT II has been also transferred and used for the PDP study in many countries including Turkey, Vietnam, Pakistan, Bangladesh, Indonesia, Azerbaijan and China.

Daily basis analysis can simulate operations of peak power stations, thus can evaluate more accurately power system cost, as compared with monthly Load Duration Curve models such as WASP. With daily basis analysis, each power station can be simulated to start and stop within a day or rest during weekends according to the daily duration curve.

PDPAT functions primarily as a capacity expansion analysis system, with limited capability to model hourly power systems operation in detail. Main Functions:

- Calculation of System Operation Cost (Capital, Fuel and O&M Cost)
- Simulation of Daily, Weekly and Yearly Generation
- kW, kWh and Fuel Balance (Monthly and Yearly)
- Economic Calculation for Power Exchange
- LOLE Calculation, etc.

PDPAT II has the following features:

- Time unit of operation is a one-day basis
- Demand curve shape is input on an hourly basis
- Pumped storage optimization timeframe is limited to one day
- Objective function includes annual expense and development plan cost
- Interconnections with up to 10 other systems can be represented
- Reliability and power trading can be represented

### 2.4.5. MARKAL/TIMES

The Integrated MARKAL-EFOM System (TIMES) system is a long-term capacity expansion model for national level energy/economic/environmental systems developed in a collaborative effort by the International Energy Agency’s Energy Technology Systems Analysis Programme. It is designed for analysis of the entire energy sector (i.e., not just the electric sector). MARKAL/TIMES is used in 70 countries by 250 institutions (of which 75% are active users). The source code is distributed free of charge by signing a Letter of Agreement not to provide any part of the ETSAP models generator to any third party. The code is written in GAMS, which is a commercial language and must be purchased. The commercial software costs US$20,000 per license. The most demanding part is training and learning, which takes some months.

The time and expertise in learning MARKAL/TIMES is similar to that of Balmorel, both of which are implemented in the GAMS modeling language.

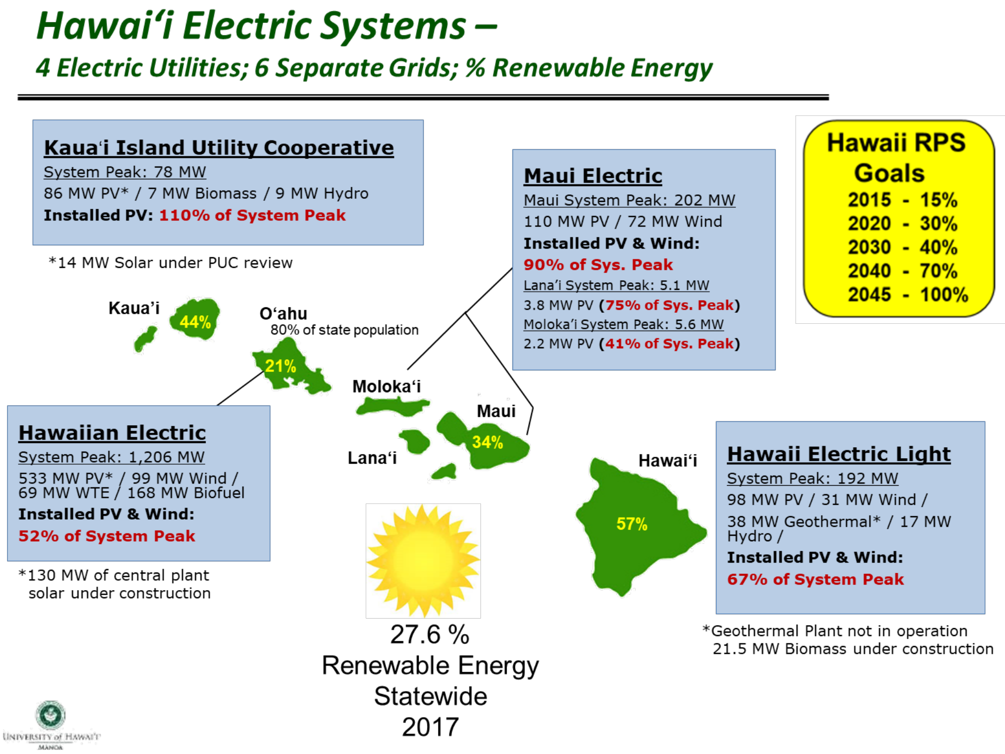
MARKAL/TIMES are general purpose model generators tailored by the input data to represent the evolution over a period of usually 20 to 50 or 100 years, of a specific energy-environment system at the global, multi-regional, national, state/province, or community level. Each annual load duration curve, hence each annual variable can be detailed by as many as desired time slices, which is user-defined at three levels: seasonal (or monthly), week days – weekends, and hour of the day. All thermal, renewable, storage and conversion technologies can be simulated by the model. MARKAL/TIMES finds the “best” Reference Energy Systems (RES) for each time period by selecting the set of options that minimizes total discounted system cost or the total discounted surplus over the entire planning horizon, within the limits of all imposed policy and physical constraints.

## 2.5. CASE STUDY: GOOD PRACTICE IN POWER DEVELOPMENT PLANNING IN HAWAII

Hawaiian Electric Company, a major investor owned utility in Hawaii, and its subsidiaries, Maui Electric Company, and Hawaii Electric Light Company, serves 95% of the state's 1.4 million residents on the islands of Oahu, Maui, Hawai‘i Island, Lana‘i and Moloka‘i. The only other major power system is on the island of Kaua‘i that is own and operated as a cooperative. The island power systems have no interconnections between them and each island must provide all its power and energy requirements independently from the others.

The Hawaiian Electric Companies continue to evolve their planning processes to meet their 100% renewable energy requirement by 2045. The fundamental goal for both the current Power Supply Improvement Plan (PSIP) and the proposed Integrated Grid Planning (IGP) processes described below is to develop the least cost long term plan that meets their planning principals and objectives and a short-term action plan that supports multiple possible future pathways (least regrets) to their ultimate goal of 100% renewable energy. The primary improvements made in the IGP process are the addition of distribution planning and market-based solutions into the planning process. This provides a more holistic approach, reduces the uncertainty of the costs of assumptions, and streamlines the regulatory approval process.

*Figure 9: Overview of the Island Power Systems in Hawaii*




*Source: HNEI/GridSTART*

### 2.5.1. The Power Supply Improvement Plans (PSIP) planning process

The current planning process used by the Hawaiian Electric Companies to produce a long-range power supply plan is the Power Supply Improvement Plans (PSIP) planning process[6]. This PSIP, which the companies filed at the end of 2016, adhered to several key Renewable Energy Planning Principles.

**Renewable Energy Planning Principles**

1. **Renewable energy is the first option**. We plan to aggressively pursue cost-effective renewable resource opportunities that work toward lowering generation costs on the grid. Additional renewable resources can be added cost-effectively, ahead of RPS requirements, as the technology of energy storage matures, and costs decline. Removing Hawaii from the volatility of world energy markets gives future generations a tremendous advantage and creates a clean energy research and development industry for our state.
2. **The energy transformation must include everyone**. Electricity is essential. Our plans, as well as public policy, should ensure that ratemaking Is fair and equitable, and ensure access to affordable electricity—especially those least able to buy self-generation and energy storage.

[6] The full Power Supply Improvement Plan report developed by The Hawaiian Electric Company is available at https://www.hawaiianelectric.com/about-us/our-commitment/investing-in-the-future/integrated-grid-planning

3. **Today's decisions must not crowd out tomorrow's breakthroughs**. Our plans keep the door open to developments in the rapidly evolving renewable generation market. We must be able to easily accept new, emerging, and breakthrough technologies that are most cost-effective and more efficient when they become commercially viable.
4. **The power grid needs to be modernized**. Energy distribution is rapidly moving to the digital age. We must re-invent our grid to facilitate a 100% renewable energy generation portfolio and enable technologies such as demand response, dynamic pricing, grid-edge devices, and electrification of transportation. Flexible generation Is also needed to better integrate renewables.
5. **The lights must stay on**. Reliability and resiliency of service and quality of power Is vital for our economy, for our national security, and for critical societal infrastructure. Our customers expect it, deserve it, and pay for it. All our plans must maintain or enhance the resiliency of the network—the grid—that delivers energy to the military, businesses, and homes.
6. **Our plans must address climate change**. Power plants are significant producers of greenhouse gas emissions. We have reduced those emissions more than 15% over the past five years through 2015. Still, our plans must go further to reduce the warming of our planet and to minimize the impacts climate change will have on the energy-delivery network—rising sea levels, coastal erosion, increased temperatures, and erratic storm activity.
7. **There's no perfect choice**. No single energy source or technology can achieve our clean energy goals and every choice has an impact, whether it's physical or financial. While we can mitigate those impacts, attaining our 100% renewable energy goal has major Implications for our land and natural resources, and the state economy. We seek to make the best choices by engaging with customers, regulators, policy makers, and other stakeholders.

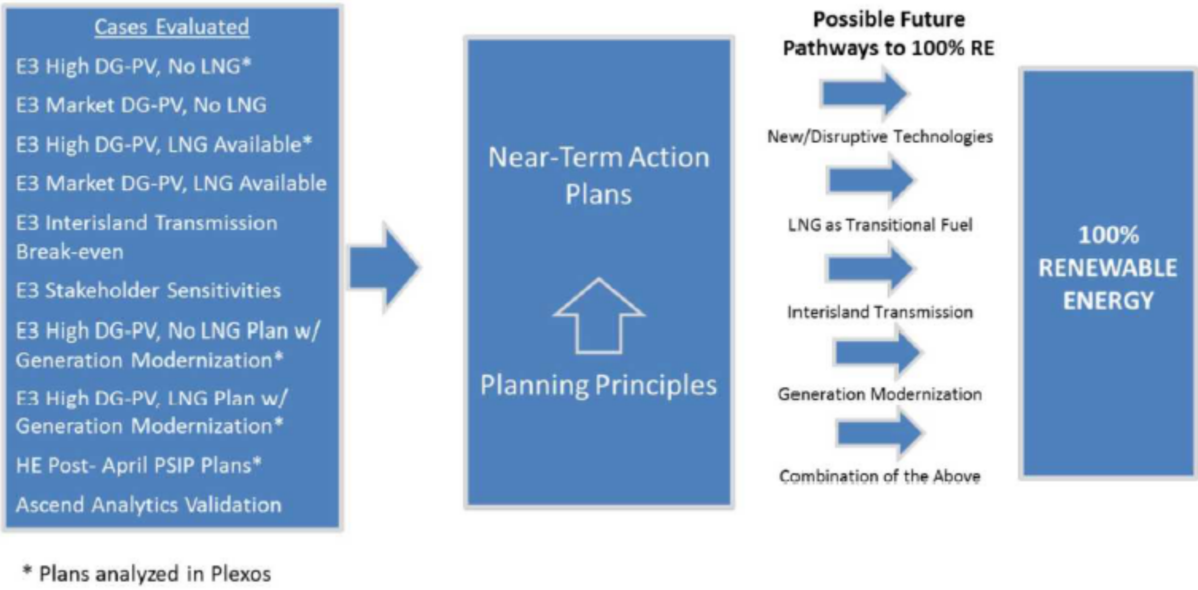
Though all the above are critical principles for planning or that there are other principles that that are more critical (reliability of natural gas resource, for example), it is important to develop these principles as the first step in the PDP process. In this way, the process focus will be on solving these issues and to ensure that the PDP fully cover all the stated principles. Coordinating with stakeholders though establishing working groups can help facilitate the development of the principles.

### The PSIP process

The overall flow process for the PSIP is shown in Figure 10 and should be viewed in conjunction with the overall analytical process summarized in Figure 11 below.

The near-term action plan filed in 2016 is based on long-term analyses that produced various resource plans through 2045. The near-term action plan focuses on immediate actions from 2017 through 2020; the longer-term views, based on the best information currently available, reflect potential actions over the period beyond 2021.

*Figure 10: Overall Process for Development of the PSIP Action Plan*




*Source: HNEI/GridSTART*

The simplified diagram in Figure 11 depicts the various models and tools involved in the overall analytical process used to develop and evaluate resource plans. For the inputs to these models, data sets from the previous PSIP, the Post April PSIP, were refined based on updated forecast information and input from stakeholders.

Using information from these datasets, the RESOLVE model was used to develop:

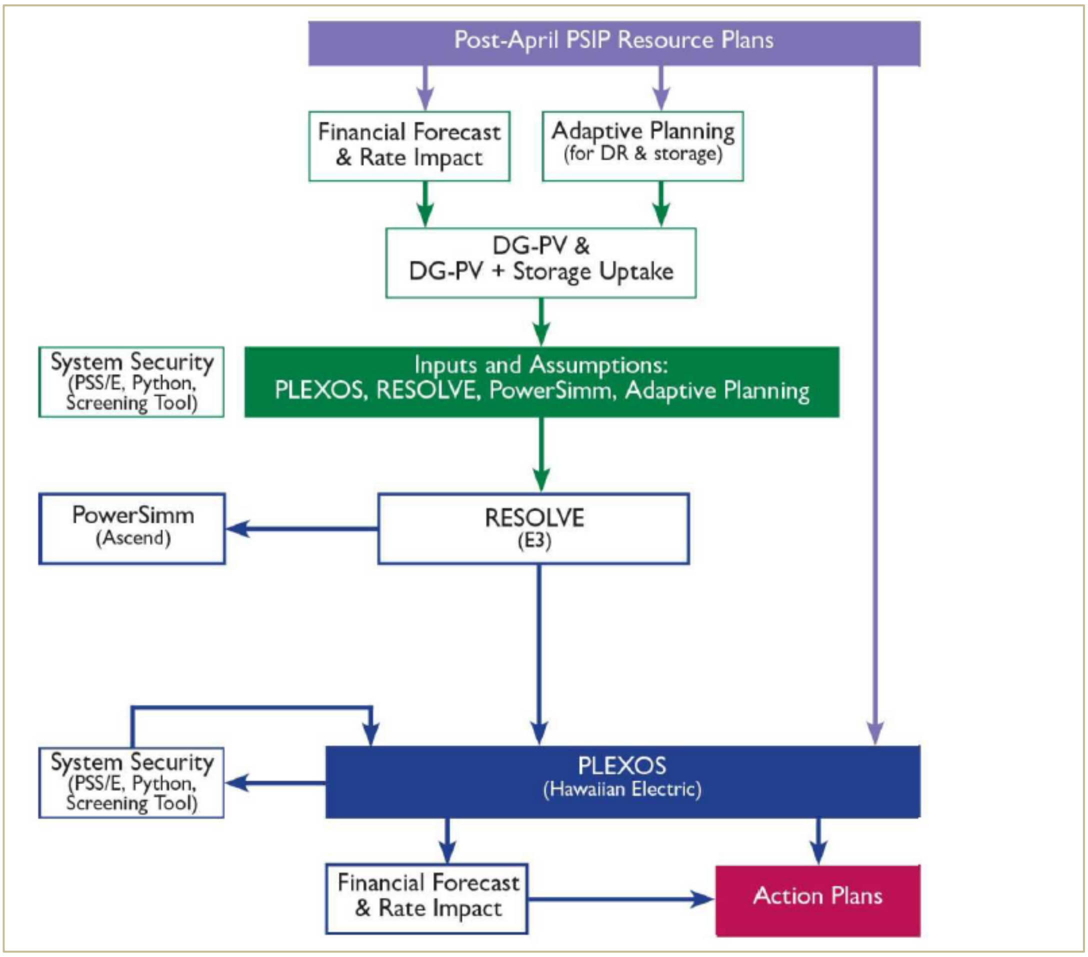
- Optimal resource portfolios from 2020 to 2045 that meet the RPS objectives while minimizing costs.
- Reference case portfolios using a set of base case assumptions (developed by the Companies) as well as several sensitivities (using stakeholder input and Company assumptions).
- An upper bound estimate of the benefits that interisland transmission could provide.
- A starting point for the PLEXOS analysis (from RESOLVE reference portfolios) that incorporated more detailed operational and transmission constraints on the system.

The Companies used PLEXOS for all hours within each year of the plan, to both validate and identify any additional resource needs (beyond the RESOLVE portfolios) to ensure reliable system operation.

The PowerSimm model was used to validate the PLEXOS results, as well as to test the least-cost portfolio RESOLVE findings. This validation confirmed the general findings of RESOLVE and PLEXOS, including early storage build-outs, the need for and value of storage, and cost-effective renewable procurement above RPS to take advantage of federal tax incentives before they expire.

These resulting portfolios were then run through financial modeling to determine the forecasted rate impact and develop the near-term action plan.

*Figure 11: Overall PSIP Modeling Process*

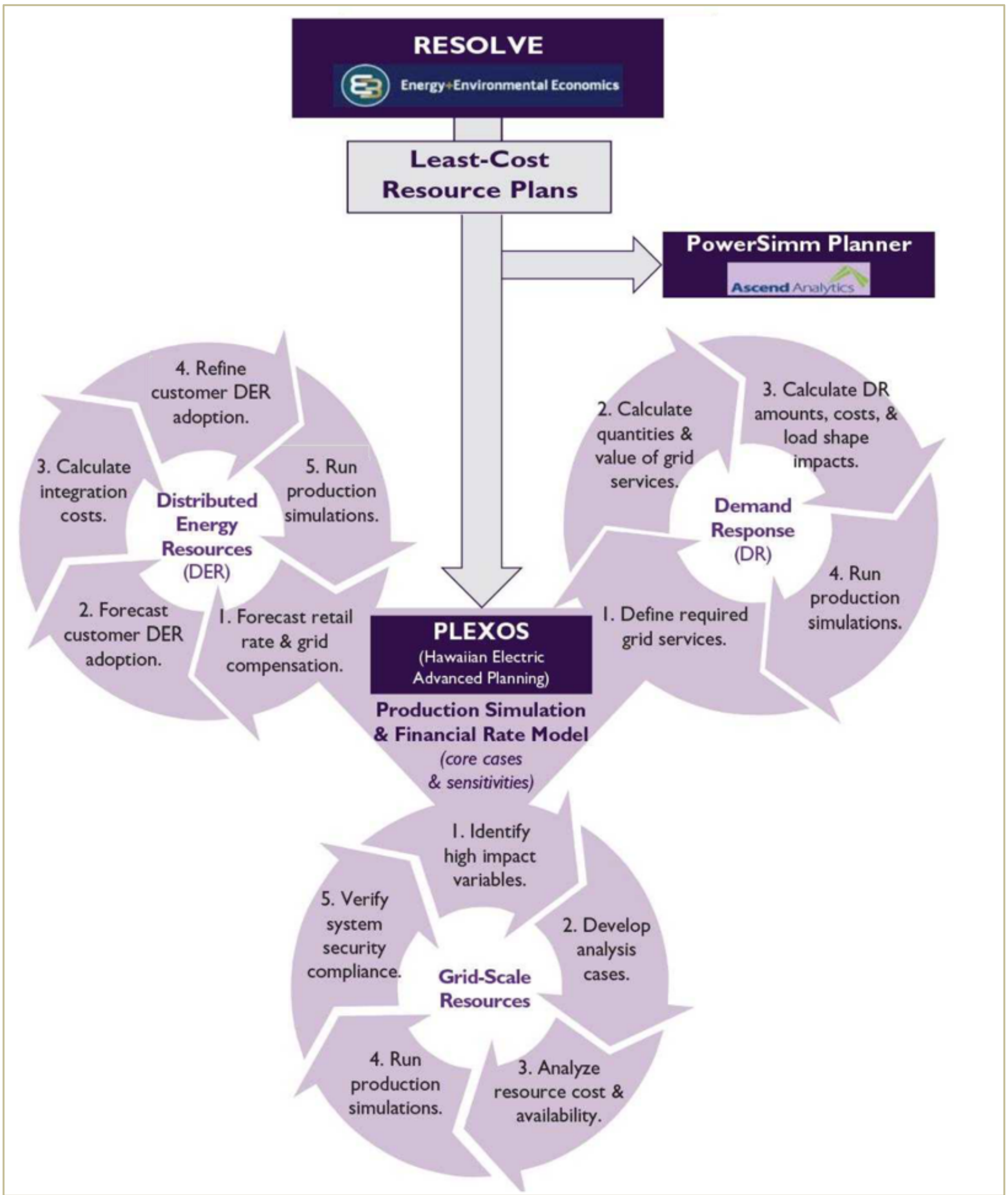



*Source: HNEI/GridSTART*

## Optimized Analytical Process

To conduct the analytics in the modeling process summarized in Figure 11, the Hawaiian Electric Company developed an innovative and transparent process to optimize all resources including DER, DR, and grid-scale resources. Figure 12 depicts the flow of the modeling tools and the optimization of DER, DR, and grid-scale renewables.

*Figure 12 PSIP Optimization Process*




*Source: HNEI/GridSTART*

## Analytical Models

Several analytical modeling tools were used to develop the PSIP. The Hawaiian Electric Companies and their consultants performed overlapping analyses to develop a series of alternative plans. Then, from those plans, near-term action plans were developed for each operating utility with the goal of providing reliable energy at a reasonable cost to its customers while reaching our 100% RPS goal.

These modeling tools include:

- RESOLVE Optimization Model and Long-Term Case Development: The RESOLVE tool used a reserve margin methodology to create the resultant plans.
- PowerSimm Planner: By introducing stochastic simulations into the modeling framework, PowerSimm can output a range of possible future costs for each portfolio. By summarizing

the range of costs through a risk premium, the utility can directly compare the merits of trading off expected costs for higher risk.

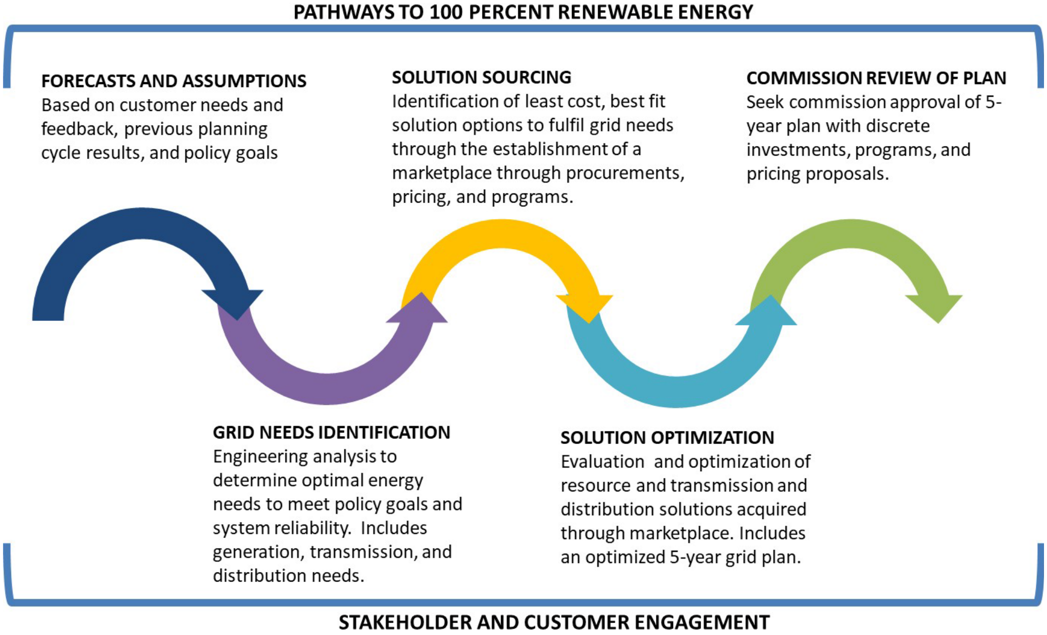
- PLEXOS for Power Systems: The PLEXOS for Power Systems modeling tool, performs hourly and sub-hourly analysis (fully incorporating the DER and DR portfolios) and provides hourly dispatches that are then analyzed in PSS/E for system security. The outputs are also used in the Financial Forecast and Rate Impact Model.
- Adaptive Planning for Production Simulation: Adaptive Planning for Production Simulation (AP) model evaluates the capability and benefits associated with customer-owned assets: traditional Demand Response (DR) devices, customer-owned batteries installed with or without PV systems (DER), and electric vehicles (EV). The analysis ensures that DR and DER assets are optimized as a portfolio fully considering the flexibility and limitations associated with these assets.
- DG-PV Adoption Model: The DG-PV Adoption Model addresses DER integration forecasts. The model forecasted market DG-PV and DG-PV paired with battery customer adoption amounts for self-supply, SIA, and potential future DG-PV products while also considering related integration costs.
- Customer Energy Storage System Adoption Model: The Customer Energy Storage System Adoption Model forecasts customer adoption of distributed storage when compensated at avoided cost for providing grid services through the proposed DR programs.
- PSS/E for System Security Analysis: PSS/E performs simulations for a specific set of conditions (such as unit dispatch and system load). Load flow simulations are performed to determine potential overload and voltage problems under steady-state conditions for various system configurations (normal, N-1, or N-1-1). Dynamic simulations are performed to evaluate frequency, voltage, and rotor angle stability of the transmission system and its components. A screening tool is used to screen the hourly dispatch from the PLEXOS production simulations to select "typical" and "boundary" hours in a particular year based on frequency response profiles for loss of generation contingency events.
- Financial Forecast and Rate Impact Model: The financial model takes inputs from the Production Simulation system cost files, as well as other general planning and forecasting assumptions to calculate revenue requirements and associated bill impacts for each theme.

### 2.5.2. THE INTEGRATED GRID PLANNING (IGP) PROCESS

Building upon the PSIP planning process that was completed in 2016, the Hawaiian Electric Company is proposing a revised planning process called the Integrated Grid Planning process, illustrated in Figure 13[7]. This process aims to establish a market for grid solutions that is tightly integrated into the optimization and decision-making process, thus increasing the number of market opportunities for unbundled grid services.

[7] The full Integrated Grid Planning report developed by The Hawaiian Electric Company is available at https://www.hawaiianelectric.com/about-us/our-commitment/investing-in-the-future/integrated-grid-planning

*Figure 13: Integrated Grid Planning Process*



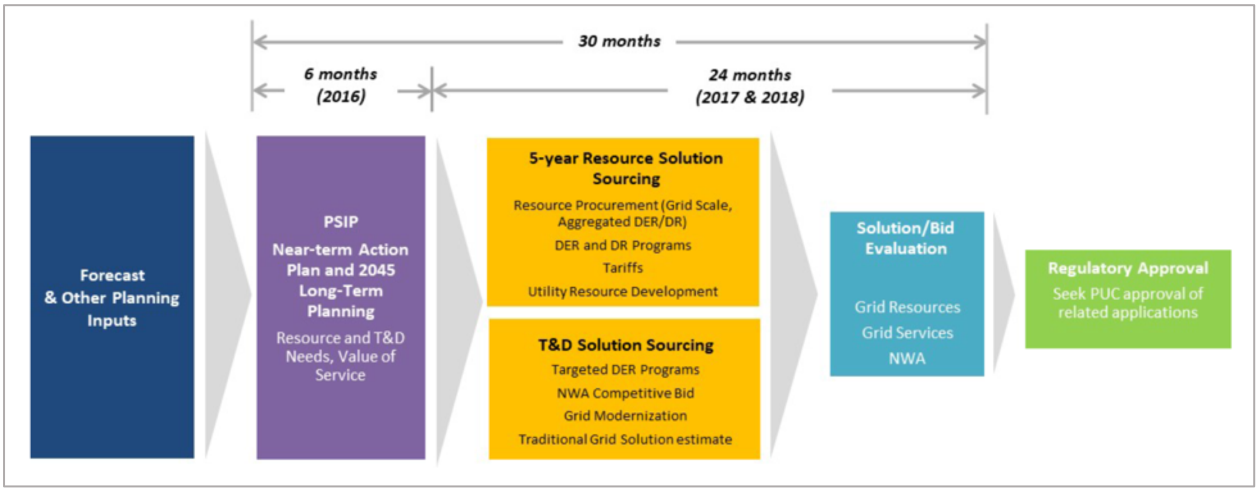

*Source: HNEI/GridSTART*

Other highlights of this planning process include:

- Establishing customer-centric planning that yields customer value from market-driven alternatives that address resource, transmission, and distribution needs
- Creating greater market opportunities for distributed energy resource and demand response providers and grid-scale developers
- Enabling the development of an optimal portfolio of solutions to address resource, transmission and distribution needs
- Maintaining transparency through active multi-level stakeholder engagement and an independent technical advisory panel
- Implementing a streamlined 18-month planning process that culminates in a 5-year integrated plan with discrete proposals submitted to the Commission for review

The starting point for redesigning the planning process is the prior PSIP and current sourcing process, as conceptually illustrated in Figure 14 below. The utility took a major step forward in the development in the PSIP process, methods, and tools used to conduct the PSIP analysis, but it is necessary to advance planning much further to create a fully integrated planning process. For example, the PSIP did not fully integrate the distribution planning analysis with the resource-transmission assessment, which is essential given the importance of distributed resources in Hawai`i. The Hawai'i Public Utilities Commission recently noted this gap, stating that "achieving this goal will depend on the Companies' ability to work towards a more complete integration of the distribution planning and a refinement of the resource and transmission planning process."

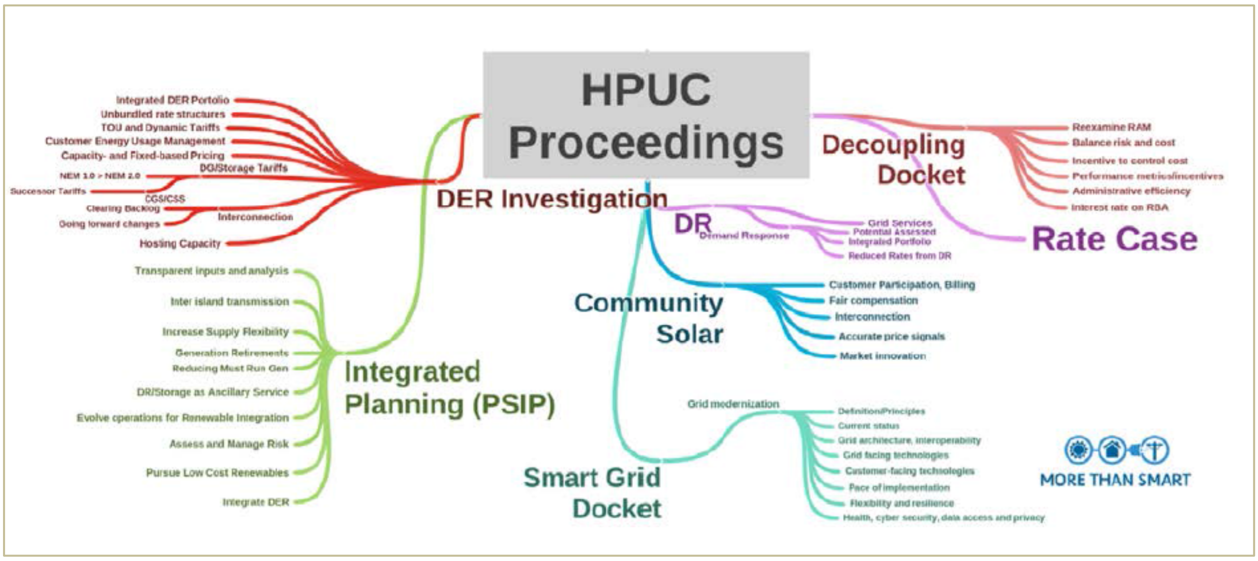
*Figure 14: Existing System Planning & Solution Sourcing Process*




Source: HNEI/GridSTART

The entire current process of planning, solution sourcing, and evaluation extends 2½ years from forecasting through final evaluation. The resulting solutions are not fully optimized in the evaluation process, and the solution sourcing for resources and T&D solutions do not converge. This is partially due to these processes running independent of each other after the PSIP in relation to the multiple proceedings, each with its unique timetable, as illustrated in Figure 15.

*Figure 15: Hawai'i PUC Proceedings*



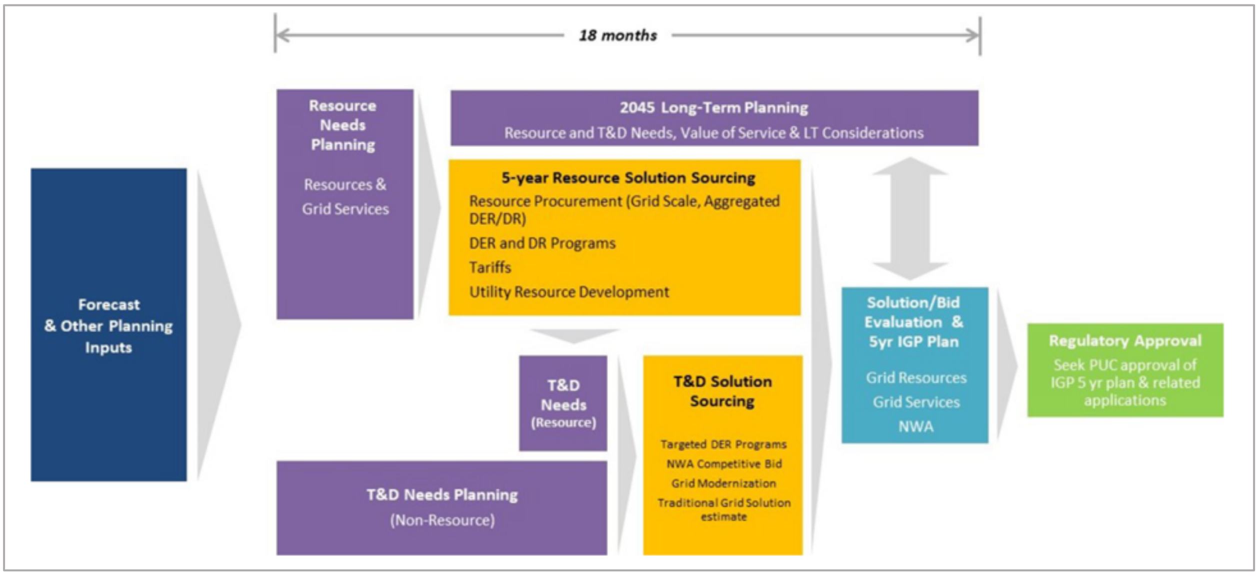

Source: HNEI/GridSTART

The challenge did not lie solely with the need to integrate distribution planning. A complete integration also requires incorporating market-based solutions into the heart of the planning process to develop more optimal outcomes for customers, rather than including market engagement as the last step in a long chain of serial activities based on assumptions and modeling estimates. While more complex to initially implement, this approach enables Hawai`i to reach its goals with a more complete planning analysis and consideration of market-based solutions. This process also affords greater opportunities for solution providers to participate and innovate, with the potential to spur economic development for the State. In this regard, we believe this approach moves ahead of the integrated distribution planning initiatives underway in several states

In comparison, the integrated distribution planning approaches being developed in other states do not fully integrate planning analysis because they typically conduct resource, transmission, and distribution planning separately. For example, the California and New York methodologies stack the results of separate planning analyses. A comparatively simple stacking of results may miss benefits or impacts that span across multiple parts of an electric system. Furthermore, these approaches follow more traditional processes, where identification and sourcing of options is the last step or occurs after planning is completed. As such, they do not reflect an optimization or the true incremental "net need" or net value. Therefore, these approaches are unable to identify solutions that address multiple resource, transmission, and distribution needs collectively.

IGP will also consider resiliency policy objectives, how energy planning can spur economic development of smarter cities and communities through the electrification of other sectors (e.g., transportation), optimal land use, and job creation. Finally, this process is a closed loop that uses the results of the prior plan (in this case, the PSIP action plan results and DR programs) as well as any identified major transmission and distribution capital upgrades as inputs. The IGP and sourcing process is illustrated in Figure 16 below.

*Figure 16: Integrated Grid Planning & Solution Sourcing Process*




*Source: HNEI/GridSTART*

The IGP process will develop input assumptions and then identify resource needs (grid resources and grid services) using the RESOLVE capacity expansion model, the PLEXOS production simulation model, and PSS/E transmission planning software. The output of this first step is to quantify resource needs in technology-neutral terms with standard definitions.

The IGP process would then initiate market-based solution sourcing/procurement for the resource needs identified in the first step. Solutions include grid-scale resources and aggregated DER/DR as well as DER and DR programs, tariffs, and resource development by the Companies. Sourcing will involve two parts, starting with a request for information ("RFI") along with initiating program/tariff options. The second part will involve incorporating the T&D needs into a request for proposals ("RFP") and the resulting competitive solutions.

Information received from the solution sourcing/procurement RFI is used to identify T&D needs to integrate these resources. Additionally, T&D needs that are identified from ongoing non-resource planning work will be aggregated with resource-related T&D needs. The aggregated T&D needs will inform market participants to improve resource and grid services proposals in the subsequent resource/grid services RFP.

This also includes a T&D solution sourcing/procurement. Targeted DER programs, non-wires alternatives that are competitively sourced, grid modernization investment, and traditional grid solution estimates will be considered. The results from the T&D solution sourcing and resource solution source processes will provide the complete cost of actionable solutions to address the resource and T&D needs.

The final task is to evaluate the alternatives and develop the five-year action plan. The resource, grid services, and T&D solutions received from the solution sourcing/procurement will be evaluated to create an effective portfolio and related action plan that addresses policy goals and customer needs. Also, the long-term planning to 2045 will be completed and informed by the near-term action plan. The long-term plan will be published and include key considerations for further discussion on important factors, such as land use, to identify pathways to Hawai`i's goals. The five-year action plan will be submitted to the Commission along with related applications for approval.

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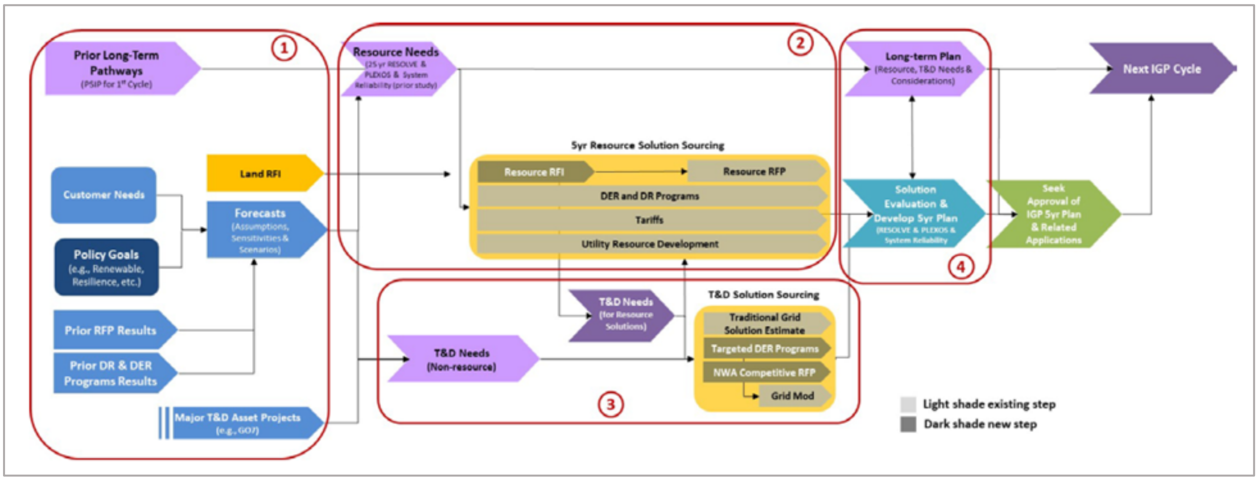
The IGP planning Process and Methods are organized around the four major steps as detailed in Figure 17 below. The major steps are:

1. Forecasts and Planning Inputs
2. Resource Needs & Sourcing
3. Transmission & Distribution Needs & Alternatives
4. Near-term Action Plan & Long-term Pathway

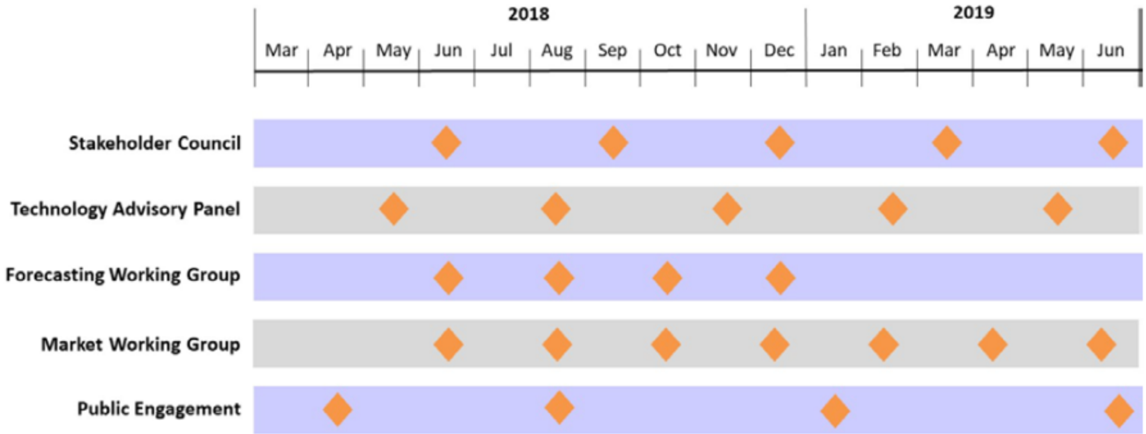
*Figure 17: IGP Process Major Steps*




Source: HNEI/GridSTART

It is anticipated that the IGP process will require a coordinated set of ongoing engagements with customers and stakeholders in support of the first IGP cycle, as illustrated in the draft schedule in Figure 18 below.

*Figure 18: Stakeholder Engagement Draft Schedule*




Source: HNEI/GridSTART

## Key takeaways for Vietnam from the Hawaii case

- As Vietnam will transition to a competitive market and increased renewable energy, the power sector will see major changes in the near-term. A detailed focus on the next 2-3 years is critical for Vietnam. In addition, it will take some time to gather and analyze the data required to properly model the changing power system. The next 2-3 years is critical for Vietnam to stay focused on data collection and modeling, so a robust power development plan can be completely as soon as possible.
- Market services shall be unbundled and separately priced (some regulated, some competitively priced). As different generating plants, distribution companies and customers will be able to provide those services, it's important to properly model the new market structure.
- Developing a tariff forecasting model for Vietnam will be instrumental in evaluating the impacts on retail tariffs as a key input on the feasibility of an option. Using the tariff forecast

as part of the feedback loop to the demand forecast will reflect the elasticity of electricity prices and reduced demand when prices are forecasted to rise significantly.

- It should be noted that Hawaii takes 18 months to create a 5-year plan. This is indicative of the high level of data collection analysis, stakeholder support, intensive level of options and scenarios to develop, model and analyze and finally to develop a robust IRP. The amount of time for completing a PDP in the future will take longer and require additional resources including experts with new skills and capabilities.
- Given that new distributed generation and demand-side resources will take a larger role in filling the system services requirements in the future, distribution planning must become become part of the planning process.

## 2.6. PDP ROLES

A formal stakeholder review process is an international best practice for PDP type of studies. Most of the international examples in the appendix involved a stakeholder process. In the U.S. and other countries, a particularly successful model that has emerged (especially in the context of planning for evaluating high renewable energy scenarios) is to engage two distinct groups in the analysis process. Though they may or may not have been performing the actual modeling work, one group was closer to the detailed modeling work, providing detailed inputs (e.g., historical data, technical characteristics), and spending more time reviewing intermediate and final results. This group often consisted of engineers from operations and planning. The other group tended to be higher level, would meet less frequently, and included people from senior management, policy makers, representatives from the donor community and other interested parties. These two multi-agency groups are described as follows:

- The **Technical Advisory Group (TAG)** is composed of policy-makers, regulators, power system operators, variable RE and conventional power plant owners, technical experts, and civil society. The TAG's roles include determining the study objectives and assumptions, defining scenarios, reviewing the modeling team's methods and data sources, interpreting and validating results, and linking study results with policy and regulatory processes.
- The **Modeling Working Group (MWG)** reviews the recommendations from the TAG and will be responsible for implementing the analysis, including assembling and validating input data, analyzing and verifying results, and compiling technical documentation to communicate findings.

Recent power sector planning efforts in other countries have demonstrated the value of extensive stakeholder engagement through a TAG and an MWG to harness the experience, judgment, and expertise of those familiar with the power sector, and therefore maximize the accuracy and benefit of planning studies. Two examples are cited below.

***<u>India</u>***

With support from USAID and NREL, the Government of India recently completed a major study to evaluate the operational impacts of achieving ambitious solar and wind integration targets. The study was conducted by a core modeling team consisting of representatives from India's Power System Operation Corporation, Ltd.—which is the national grid operator, with representation from the National, Southern, and Western Regional Load Dispatch Centers—along with the NREL and Lawrence Berkeley National Laboratory. A broader modeling team also participated in the study and consisted of more than 20 engineers representing central and state agencies: Central Electricity Authority, POWERGRID (the central transmission utility), and State Load Dispatch Centers in six Indian states. The team had constant support and guidance from the Ministry of

Power. All modelers received formal training on the use of the production cost modeling software that formed the basis of the operational modeling, and each of these states has worked toward customized production cost models for their own planning and analysis.

Beyond the modeling team, technical stakeholder review was provided by three teams of Grid Integration Review Committees (India's version of TAGs), which met four times in each of three locations. The Review Committees included more than 150 technical experts from central agencies (the Central Electricity Regulatory Commission, Solar Energy Corporation of India, National Institute of Wind Energy), state institutions (grid operators, power system planners, RE nodal agencies, distribution utilities), and the private sector (RE developers, thermal plant operators, utilities, research institutions, market operators, other industry representatives). The Review Committees provided peer review and guidance at all stages of the study, from scenario design and modeling assumptions through implications of results.[8]

***Philippines***

Similarly, a solar and wind grid integration study in the Philippines was conducted by an MWG consisting of two staff each from five organizations: the Philippine Department of Energy, the Grid Management Committee (a division of the Philippine energy regulatory agency), the National Grid Corporation of the Philippines (the transmission system operator), the Philippine Electricity Market (the electricity market operator), and NREL. The MWG convened via teleconference every 1-2 weeks throughout the 18-month study to share data (provided under a non-disclosure agreement among the five agencies), agree upon methodology and key assumptions, validate inputs to and outputs of the production cost model, and analyze results.

The MWG provided joint presentations to the Technical Advisory Committee (the Philippines' version of a TAG) and reported updates on the study's progress to their respective agencies' management. The TAG for the Philippines' grid integration study consisted of two senior officials (one permanent and one alternate) from each of the MWG organizations, as well as other government agencies, academic and technical institutions, international experts, and private sector organizations. The TAG met in person three times over the course of the study: first to define the scenarios for analysis, then to validate initial model outputs, and finally to review the final results. At the outset of the study, the MWG and TAG were codified into policy via a Department Circular issued by the Philippine Department of Energy.[9]

Please see Appendix A1 for additional details about the RE integration studies for the Philippines and India.

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[8] Additional details are available in David Palchak, Jaquelin Cochran, Ali Ehlen, et al. 2017. Greening the Grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. I -- National Study. NREL/TP-6A20-68530. https://www.nrel.gov/docs/fy17osti/68530.pdf.

[9] The Department Circular formalizing the MWG and Technical Advisory Committee for the Philippines—including responsibilities and membership of each group—is available here: https://www.doe.gov.ph/sites/default/files/pdf/issuances/dc_2015-11-0017.pdf. Additional details are available in Clayton Barrows, Jessica Katz, Jaquelin Cochran, et al. 2018. Greening the Grid: Solar and Wind Grid Integration Study for the Luzon-Visayas System of the Philippines. NREL/TP-6A20-68594. https://www.nrel.gov/docs/fy18osti/68594.pdf.

# SECTION 3: ASSESSMENT OF CURRENT PPD METHODOLOGY

## 3.1. ELEMENTS OF PDP-7/RPDP-7 PROCESS

### 3.1.1. ADVANTAGES AND DISADVANTAGES OF THE PDP-7 PROCESS

The PDP-7 was established in accordance with the Electricity Law No. 28/2004/QH11 and the process was guided in Decision No. 42/2005/QD-BCN dated 30/12/2005 of the Ministry of Industry regulating the content, appraisal and approval of the PDP.

The main processes of PDP-7, following Decision 42/QD-BCN, comprises of 15 sections specified in Table 4 below. The advantages and disadvantages of the process are provided within the table.

*Table 4: Advantages and Disadvantages of PDP7*

| | Elements of the PDP7 process | Advantages | Disadvantages |
|---|---|---|---|
| 1 | The current state of national electricity system | Demand information is collected at the national, regional, provincial/utility basis. Some information is collected on customer classes. | For completing and IRP, there is need for a lot more data, such as appliance saturation rates, equipment efficiency, energy efficiency programs and estimated costs, smart meter penetration<br>Historical customer demand information will be needed to analyze consumption patterns and EE impacts on peak and energy consumption<br>PDP 8 will be far more complex and require much effort to collect and analyze the data and complete the multitude of scenarios required for a robust plan. |
| 2 | Assessment of the implementation of the previous PDP | Providing a good feedback mechanism | Should be performed on a more regular basis, such as annually to make mid-course correction, if needed |
| 3 | Overview of the Socio-economic situation and the Energy system in Vietnam | Economic development will impact demand | GDP is one input among others that will impact on the demand – customer choice is missing (self-generation, storage, demand response, load shifting, etc.) especially when retail tariffs reach full cost of service |
| 4 | Forecast electricity demand | National and regional analysis is performed | Demand forecast must reflect elasticity, energy efficiency resource plan, demand response, |
| 5 | Economic and technical norms of power plants and grids | All models need the economic and technical | Environmental aspects should be collected and used in the analysis rather than calculating the |

| | Elements of the PDP7 process | Advantages | Disadvantages |
|---|---|---|---|
| | | aspects of the power plants and grids | environmental impacts after the resource plan is developed |
| 6 | Assessment of primary energy sources; exploitability, import and export of energy sources and forecast of fuel prices | All these elements are key inputs into a PDP. | Fuel prices and availability should be analyzed through various scenarios to determine risks of high prices and low availability |
| 7 | Power Development Program | Action plan provides specific direction for the country, especially when demand is growing fast, and shortfalls would be devastating | PDP lacks an iterative process that reflects price elasticity, evaluation of demand-side resources, the impact of VRE expansion, and the inherent risks of the plan<br>The plan must be flexible<br>Slow development process needs to be improved (recognized as part of risk assessment) |
| 8 | Power grid development | Action plan with targeted investment is key to ensuring long-term reliability and reducing energy losses | The over-construction risk must be evaluated under scenario analysis – timing of construction must be flexible and not pre-determined<br>The cost of new networks should be evaluated within resource evaluation and not as an after thought |
| 9 | Power interconnection among neighboring country | Imports and exports provide flexibility to power sector development when there are sufficient interconnections | Consideration of Vietnam as an energy hub that encourage regional competitive energy sources |
| 10 | Rural power development program | Expected new demand is included in forecast for regions and country | No comment. |
| 11 | Dispatch and telecommunication of Vietnam's electricity system | Updating the technology on a regular basis is important, especially with smaller generating plants, storage facilities and prosumers | New software is available for forecasting wind and solar generation to reduce operating reserves |
| 12 | Environment and environmental protection in electricity development | Environmental protection is seen as an objective of the plan | Emissions are missing from the cost of generation.<br>Perhaps emission targets could be established for each year to be analyzed in each scenario. |
| 13 | Investment program of PDP | Estimating the cost of the plan is necessary to | Investments must be calculated for each scenario and used in the iterative process so that energy efficiency resources, for example, |

| | Elements of the PDP7 process | Advantages | Disadvantages |
|---|---|---|---|
| | | determine the impacts on tariffs | can be compared against supply-side resources. The investment programs must also include network impacts within the iterative process as well. |
| 14 | Economic-financial analysis of national electricity development plans | Calculating long-term marginal costs is an important part of forecasting retail tariffs<br>Looking at pricing mechanisms for private sector involvement is key to incentivize new investment | Tariff impacts should be included in all scenarios and used as feedback on demand level and energy efficiency program cost benefit analysis |
| 15 | National electricity organization mechanism | PDP analysis provides valuable input for market reform proposals | The PDP should be used by policy makers for insights on market reform, but not be the mechanism for market reform as it is a 10-year horizon and market reform must be flexible and able to change as needed |
| 16 | Intermediary report review by concerned agencies | Stakeholder involvement is important element of a good plan | Might want to consider broadening the stakeholders to include private sector representatives and to have stakeholder working groups earlier in the process to provide insights and feedback throughout the process |
| 17 | Optional – Consultants to appraise and provide feedback | An independent review and appraisal can provide valuable feedback | Working groups can provide review and throughout the process to complement consultant's efforts |
| 18 | Review by sector, ministries and provinces | Valuable feedback can come from various stakeholders | Need to include private sector, such as through website publishing of the draft PDP allowing for comments within a specified period. |
| 19 | Approval by the Prime Minister | Government approval provides investor confidence that the government has a strategy for power sector development | The plan may be too specific and variations in the plan require top of government approval |

### 3.1.2. Time Horizon

PDP 7 time horizon was 2011-2020. In today's rapid technology environment, this is a very long period to forecast.

Four years ago, wind and solar power plants were not cost competitive. Two years ago, battery storage facilities were only in the pilot testing mode. In the last five years, over 8 GW of demand response resources were added in the US. For the next 10 years, the capacity market in New England will be covered by consolidated energy efficiency programs. In many countries, prosumers (consumers that generate power) are becoming the dominant producer of electricity. LNG infrastructure has driven gas prices down in many areas of the world. Technology not only changes the perception of power sector structures, it also is changing how the perception of power markets. As Vietnam experiences opening its power market to competitive trading, it will also be experiencing how technology is clouding the traditional concepts of who is a market player, what they trade and to whom they trade.

Future PDPs will focus more on transmission planning in the future as the competitive market will dictate new resources (demand and supply-side). The rapidly energy landscape will put huge pressure on the transmission owner to build sufficient transmission to allow for trading while at the same time not to overbuild or build in the wrong location.

Many factors fluctuate only 1 to 2 years when implementing such policies as: The state changes (the policy of stopping nuclear power projects, the policy of money transfer with BOT projects, loan guarantee regulations ...); delays, risks of fuel supply projects (coal, gas); delay the investment in coal transit depots; risk from equipment suppliers.

The ten-year planning horizon is good for analyzing future investments. Typically, planners developer two-year action plans, three-year to five-year general plans and five-year to ten-year high level plans consistent with the 10-year power development plans. During the first two years, the planners develop a detail action planner making small adjustments as necessary. If the 10-year plan assumptions are no longer valid, then either planners revise the plan (as Vietnam did for PDP 7) or they completely redo the 10-year plan.

### 3.1.3. NEW REGULATIONS ON THE CONTENTS OF THE RPDP-7

From 2013, after the Law on Amendment of and Addition to several articles of the Electricity Law, No. 24/2012/QH13 was issued, the PDP preparation, appraisal, approval and adjustment has been stipulated in the Circular 43/TT-BCT issued on 21 December 2013 by the Ministry of Industry and Trade. Circular 43/TT-BCT adjusts, removes some contents and adds some new contents of the PDP, in line with Law No. 24/QH 13.

The specific objectives set out for RPDP-7 were:

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*Provide adequate electricity for the domestic demand, satisfy socio-economic development objectives with average GDP growth rates of 7% during 2016-2030:*

*o Commercial electricity: 235 – 245 billion kWh in 2020; 352 – 379 billion kWh in 2025; 506 – 559 billion kWh in 2030*

*o Electricity production and import: 265 – 278 billion kWh in 2020; 400 – 431 billion kWh in 2025; 572 – 632 billion kWh in 2030*

*- Prioritize the development of renewable energy sources for electricity production; increase the proportion of electricity generated from renewable energy sources (excluding large-scale, medium-scale and pumped storage hydro power) up to around 7% in 2020 and above 10% in 2030.*

*- Construct the power transmission grid with flexible operation and high automation capabilities from electricity transmission to distribution; develop unmanned substations and substations with 50% of human participation to increase the capacity of the electricity industry.*

*- Accelerate the program of electrification in rural and mountainous areas to ensure that in 2020 most of the rural households have access to electricity.*

It can be seen that:

1) These are specific objectives of the PDP with specific goals/targets. The objectives of providing energy to adequately supply domestic demand, to prioritize renewable energy, construct flexible transmission and accelerate the program of electrification seem to be appropriate objectives. Other objectives can be added to the next PDP such as objectives related reliability, energy losses, private sector involvement and retail tariff impacts.
2) Specific goals/targets typically are not specified but rather come out of the PDP initial process so that tariff/subsidy impacts can be reviewed, and then appropriate annual or long-term targets can be established.

### 3.1.4. Zoning of Vietnam's power system in PDP-7 and RPDP-7

Vietnam's power system covers the whole country with the length from North to South is over 1500 km. The load demand of Vietnam's power system is concentrated in the Northern and Southern ends. Northern load accounts for about 40% of total load demand; Southern load accounts for nearly 50% of total load demand; Central loading accounts for over 10% of total load demand.

PDP-7 and RPDP-7 divides Vietnam's power system into three regions: North, Central and South, linking the three regions by 500kV transmission system. This zoning defines the self-balancing capacity between the demand for electricity and the power supply in each region and determines the demand for capacity transmission and the capacity of the interconnection transmission lines.

Vietnam has great potential for renewable energy, especially wind power and solar power. Distribution of renewable energy potential is uneven and concentrated in the South, mainly in the South Central, Central Highlands and South West, where transmission distance to the load center is quite long (above 200km). Domestic coal in the Vietnam will not be enough for power plants to build in the future, new coal-fired power plants will use imported coal. PDP-7 identified the Central region very convenient for the construction of coal ports and the construction of coal-fired power plants. This area has low load, long distance transmission and needs to determine the power transmission direction and the capacity of the link line.

Major gas fields of Vietnam will be exploited: Blue Whales, Block B are also located far away from the load center. In addition, favorable locations for the construction of LNG terminal for power generation are located far from the load center, and the direction and capacity of the transmission line should be determined.

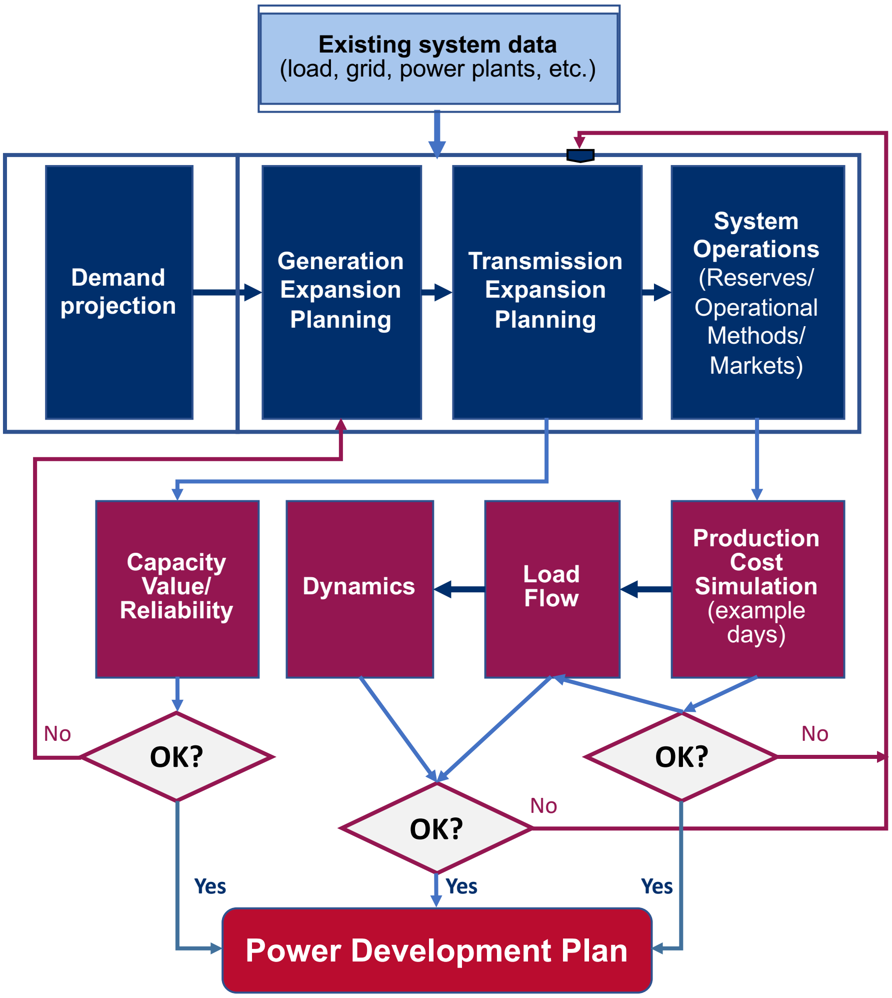
## 3.2. DESCRIPTION OF THE WORK FLOWS IN PDP-7/RPDP-7

The simplified methodology used by IEVN in PDP-7 and RPDP-7, presented in Figure 19 below, follows the general framework as laid out in Figure 3.

PDP used a synchronized approach, coordinating the generation expansion planning with the development of the transmission system. Transmission timeline assessment emphasized required backbone expansion of the three key power systems zones in the North, Central and South. PDP provided a complete list of system additions for each year and each location (over a 15-year period). The list included power generation projects and transmission grid additions for the entire country. Subsequently, RPDP-7 also considered scenarios with the increased amounts of renewable energy (including small hydropower, wind power, solar power and biomass) in 2030 (21% of capacity and above 10% of generation).

The process of preparing PDP-7 and RPDP-7 was coordinated with the planning of the coal industry and the oil and gas industry. PDP-7 and RPDP-7 also identified several technical solutions and state management mechanisms to meet the State's policies on power supply security with the enhancement of reliability.

***Figure 19: IEVN's Power source development planning methodology***

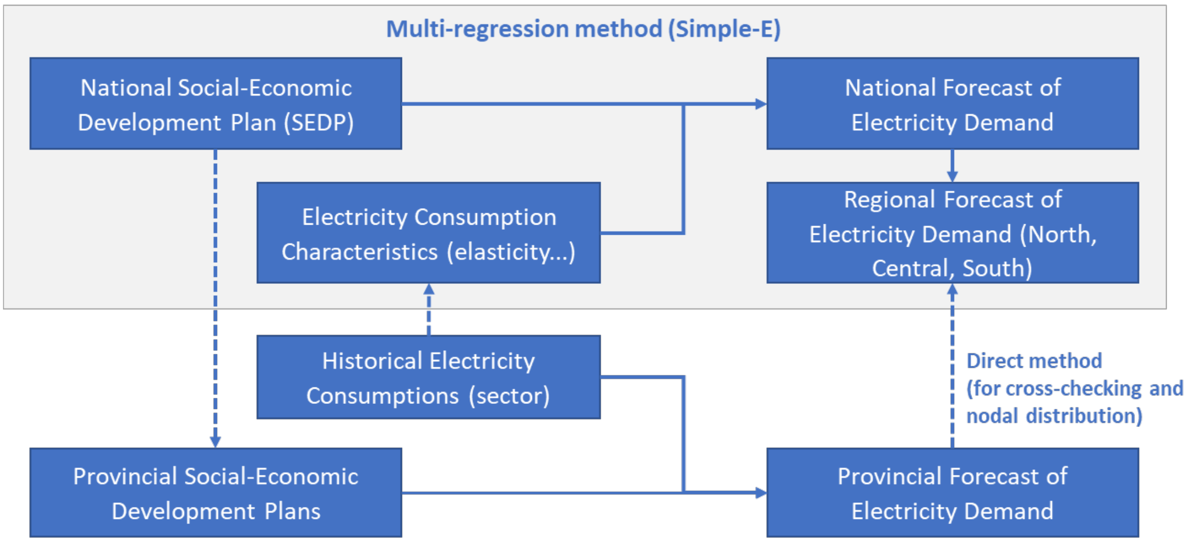



*Source: Elaborated by NREL*

### 3.2.1. Power Demand Forecasting (*Projection*)

In the PDP-7 and RPDP-7, demand forecast was developed utilizing a top-down approach by region. Demand forecast was developed for each power company (e.g. North, Central and South) and the forecasts were combined to develop maximum capacity and generation demand for the entire country. Using historical profiles, forecasts also developed typical daily load shape for future years. Profiles were developed for each season for each region combined to develop demand profile on national level. Load profiles were used to develop the average and maximal demand for each month. Forecast also included estimated impact of the national energy saving and efficiency programs (VNEEPs) on the demand growth. Total load was distributed at high voltage grid nodes (220 kV and 500kV) for the entire planning period.

***Figure 20: Long-term Demand Forecasting***




*Source: Compiled by V-LEEP team*

Due to the consistently high historical growth rates in Vietnam, using a simple top-down approach was adequate for forecasting future demand. A top-down approach involves the estimate of demand at a generation level (i.e. forecasting MW and GWh sent-out). This technique includes implicit assumptions about the future losses and does not permit a breakdown of demand by consumer sector.

Advanced demand forecasting methodologies utilize a bottom-up approach. A bottom-up approach forecasts demand at the consumer level (i.e. electricity sales forecast). This sales forecast is then distributed to system nodes at different voltage levels by summation. Summation is done for each individual consumer level sales forecast, using the consumer load factors and by applying estimated losses.

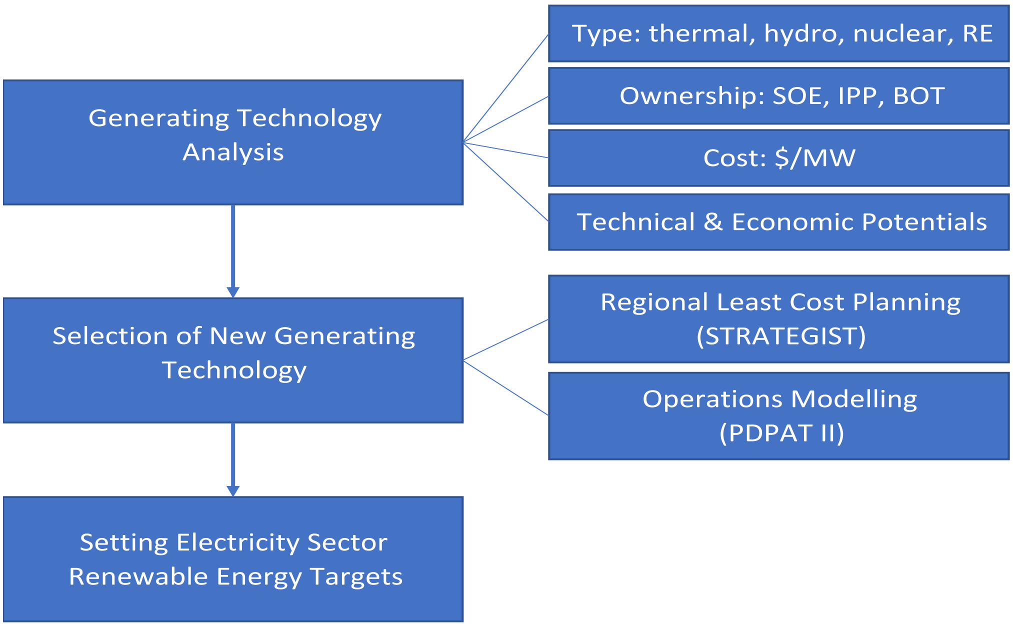
Key issue with demand forecasting is that the Vietnam statistical system is lacking data inputs and insights on electricity consumption to allow full bottom-up forecasting approach. Availability of input data impacted accuracy of PDP-7 forecasts and might impact the accuracy of future electricity demand forecasting. In addition, lack of socio-economic growth data could also affect the accuracy of electricity demand forecasting using bottom-up method. Based on data availability, a hybrid approach, combining a top-down and bottom-up approach is recommended for PDP-7.

### 3.2.2. GENERATION EXPANSION PLANNING

PDP-7 followed all the required generation expansion planning steps. First analysis step addressed the status of primary energy sources used for electricity generation including the development of new hydro resources, usage of coal, natural gas and oil for electricity generation and the status of renewable technologies. Next step was the overview of potential energy sources for generation projects in Vietnam, including the options for importing electricity and electricity exchange with neighboring countries. Generation potential included the ability to exploit unused hydro potential, the ability to use domestic or imported coal, natural gas potential with the potential for developing gas pipelines. Assessment also included initial evaluation of uranium reserves and the potential for developing geothermal power plants. Fuel price forecast was done for the entire planning horizon.

Screening analysis of generation development options was conducted next, by ranking all generation options based on their investment and operating costs. Screening analysis included hydro projects and all coal and gas generation options including the possibility of electricity imports.

***Figure 21: Selection new Generation Resources***




*Source: Compiled by V-LEEP team.*

Methodology partly included the assessment of widely used power system expansion planning packages. After comparing key modelling features, software packages were selected for PDP7. As discussed in details in 3.2.9, the STRATEGIST model was selected for the least cost generation & transmission capacity expansion analysis. PDPAT II model was selected for the system operational analysis. **Operational analysis** used typical daily and weekly load shapes applying the available solar and wind generation profiles from a small number of sites. The PDP-7 and RPDP-7 studies did not use advanced models capable of analyzing the integration of large volumes of non-hydro renewable energy sources (e.g. wind and solar resources) or models capable of representing detailed transmission system.

**Generation expansion optimization analysis**, using the STRATEGIST model, developed the generation additions required to meet future capacity and energy demand for each demand scenario. The STRATEGIST model evaluated technical and economic characteristics of all proposed generation expansion options to develop optimal generation development plan for each demand scenario. Model also calculated generation by power plant type, as well as the energy exchange between regions and electricity imports and exports between Vietnam and other countries in the region. Analysis results included the optimal generation development plan for each demand scenario with the detailed list of the proposed power generation projects needed to be developed in each period. Results also proposed electricity imports and exports and the interconnections between Vietnam and other countries in the region. Analysis results included system long-run marginal cost (LRMC) that were compared with electricity prices in other countries in the region. Pricing component also addressed basic principles used in developing electricity prices and compared LRMC with the current electricity prices in Vietnam.

PDP-7/RPDP-7 did consider variable renewable energy (VRE) generation resources but not in priority order due to very high costs of energy. Wind power sources, due to their small size and very different, were modeled as 50-100 MW power modules; their typical operation shapes were taken according to the average wind speed at some investigated locations in the South and Central Coastal areas. The capacity factor was equivalent to ~ 25%. Solar power sources, due to their small size and very different, were modeled as 50MW modules.

The study addressed environmental issues associated with the proposed power generation development plan, and recommended solutions to mitigate environmental impacts. Assessment included total demand of land for substations, transmission lines and power generation projects. Finally, PDP evaluated implementation issues and proposed financial, pricing and power sector restructuring changes to facilitate implementation of the proposed power system development plan.

### Assessment

With the introduction of IRP principles, generation planning must evolve to energy resource planning so that all resources including energy efficiency and energy storage can be evaluated sis-by-side with generating resources. Models that can perform integrated planning must be analyzed and the most suitable one for Vietnam selected for PDP-8.

DR / DSM analysis should be conducted on a customer class specific and location specific basis, as demonstrated in the international examples section. Customer load profiles over different customer classes for specific transmission or distribution station locations are required to determine the potential to shift (including rebound effect) or reduce load, and to determine the locational value of the DR / DSM program.

Scenarios should all include environmental impacts, so these impacts can play a material part of the selection process rather than as a calculation of the preferred generation plan. A combination of energy efficiency programs and renewable energy may provide the lowest cost and lowest environmental plan.

New data on the operational characteristics and costs of future thermal and VRE technology should be used in detailed production simulation modeling. The characteristics should accurately reflect the capabilities and costs associated with providing system flexibility, and the ability to provide primary and secondary reserves, along with technical constraints, considerations and costs. VRE generation profiles should be location specific and, if possible, sub-hourly, at 10-minutes or less.

Integration of renewables should be modeled within the planning process. The selected long-term energy resources planning model should be able to look at ranges of production levels of wind and solar plants. Once the long-term planners have developed a list of scenarios that include renewable energy plants, shorter-terms planners with use their operations model to determine the system impacts from the renewable energy penetration of each scenario. The short-term planners will examine the various options to mitigate any additional ancillary services required by the addition of variable renewable energy plants. Possible options for examination are: gas turbined, combined cycle gas turbines with flexible dispatch, demand response, battery storage facilities and forecasting software of wind and sun that allows for improved wind and solar power predictability.

Another issue is the uncertainty of the process of power plant negotiation, development and construction. The impact on reliability and the cost of prolonged development financing must be analyzed within scenario analysis.

### 3.2.3. TRANSMISSION EXPANSION PLANNING

PDP-7 applied traditional transmission analysis approach and tool to perform: power flow, contingency analysis, stability, short circuit and voltage studies. Transmission planning was done with the PSS/E model using the 5-year intervals. Transmission planning objective was to determine the grid development program corresponding to the selected optimal power generation development plans.

Initial analysis step was to conduct the load flow for the dry and rainy seasons. Load flow was followed by additional grid operation analysis that included the steady-state and dynamic stability, corresponding to the various grid development options. Short circuit analysis was then conducted for key system nodes. Reactive power analysis assessed the grid reactive power requirements and determined the reactive power needs for the high voltage transmission grid. Renewable integration analysis included stability calculation (flicker voltage and harmonics) when integrating renewables into the grid;

Study results presented future transmission grid development in stages, e.g. defined additions to be built in the next 5 years, 10 years and tentatively planned for the final 10 subsequent years. The development plan listed high voltage substations and transmission lines needed during the planning period with the high-level development requirements for the distribution grid (110 kV, medium and low voltage).

With PDP-7/RPDP-7, the basic transmission planning is performed and directly connected to the planned generation projects. Transmission planning lacks analysis on the impacts of renewable energy projects., and the cost of transmission must be included along with generation project costs so that all resources, supply and demand, can be evaluated on a level playing field.

### 3.2.4. POWER IMPORT/EXPORT

The interconnection analysis process under PDP-7 and RPDP-7 was focused on particular power plants under development in neighboring countries. For many reasons (political, economic, tariff impact), this carries a lot of risks, especially as Vietnam opens a competitive electricity market. Proposing to construct new transmission lines assumes the interconnection will be sufficiently loaded so the transactions (buying energy priced lower than the marginal costs in Vietnam) will be sufficient to pay back the capital costs of the new facilities. This has large implications on retail tariffs or government subsidies when new transmission interconnections may dormant when the expected transactions are realized.

To mitigate the risks from power import/export, the analysis of import capacity, value, and characteristics should be performed in a detailed hourly production simulation model relative to the requirements of the Vietnamese power system with regard to energy, primary and secondary reserves (contingency and regulation reserve), transmission limits and N-1 constraints in system. The valuation of imports, and possibly exports, must be carried out with respect to different contractual terms such as firm/must take, flexible/inflexible products, varying notice levels, daily/weekly/monthly/seasonal/annual limits, flexible reserves, reserve sharing, etc. In a system with potentially significant amounts of baseload/inflexible generation (coal, renewables, nuclear, hydro with constraints on water releases), flexibility may have a value that could be provided via imports. As was shown in the international examples section, this needs to be assessed and compared to other potential options, along with the associated infrastructure.

### 3.2.5. NATURAL GAS (NG) FACILITIES FOR POWER GENERATION

Gas-fired power plants accounted for 33% of national electricity production in 2016. Gas is also supplied to produce over 1.5 million tons of nitrogen per year, accounting for 70 - 75% of the domestic demand. LPG and CNG are imported and distributed to industrial and household consumers in the country. PVN's strategy is to try to continue to supply 100% of the markets for dry gas and to increase its share of the market to at least of LPG to at least 70% of the total domestic market, as well (Le Viet Trung, 2016).

Vietnam has three main gas transportation and distribution systems: Nam Con Son gas transportation and distribution system, PM3-Ca Mau gas transportation system and Cuu Long gas transportation and system (Source: PV Gas, Annual Report, 2013).

The Thi Vai Refrigerated Storage (with a storage capacity of 60,000 tons of cold LPG) is an investment made by PVN Gas Joint Stock Corporation (PV GAS) that allows PV GAS to store a large amount of LPG, to accommodate LPG supply in the long term, provide stability to domestic supply, and contribute to national energy security.

Dinh Co Gas Processing factory and LPG importing and storage systems have been developed and operated to provide a stable source of gas for industrial development, including gas power plants of PVN and EVN, the BOT investors, the fertilizer plants and various low-pressure gas consumers.

The National Gas Pipeline System Plan foresees possible connection with the gas pipelines of ASEAN countries.

In the process of power source complex research, proposal and development, PDP-7 and RPDP-7 were kept updated with latest plans and actual investment progress of gas supply sources.

**PDP-7:**

The Draft *"Master Plan for Development of Vietnam's Oil and Gas Industry to 2015 with orientation to 2025"* prepared by Petrovietnam's Vietnam Petroleum Institute and submited to MOIT in 2010, basing on the volume of gas expected to be extracted in the continental shelf of the South East, South West and Central Region. PDP-7 considered the amount of gas used for power generation and supplied to industrial and household customers in the South East. PDP-7 also evaluated whether the expected gas production should be reduced gradually and is not sufficient for existing and planned power plants, so it proposed to consider importing LNG before 2020.

In fact, there were many uncertainties in the implementation of the Gas Master Plan.

**RPDP-7**

Within the task of studying and developing the revised PDP-7 (being assigned by MOIT at the end of 2014), the Institute of Energy reviewed the fluctuation of gas supply in the South and the Central. While PDP-7 did not take Kien Giang Complex into consideration because of the insufficient gas supply - even to O Mon II (BOT), but Kien Giang Complex was strongly proposed by PVN at that time and was finally included in the approved RPDP-7 despite unclear source of supply.

**Assessment**

Detailed analysis of the fuels (gas and coal) availability and price volatility must be included in the PDP process. Additional time and analysis needs to be spent on this issue. Cooperating with PVN is important but the PDP developers can analyze scenarios where fuel risks are assessed.

Given the very long planning horizon (10 years), commitment to a fuel plan in year zero and to stick with that plan in years 5-10 puts the country at risk. That risk must be analyzed in the PDP process through scenario analysis.

### 3.2.6. POWER MARKET DEVELOPMENT

**Power Markets**

The PDPs are to provide the ”basic principles for forming electricity price in the context of power market”. Issues in the past focused on the wholesale price for the sale of power from privately owned generation facilities.

The objective of using “basic principles for forming electricity price in the context of power market” must include the co-optimization of energy and reserves, as well as scheduling and dispatching the system relative to transmission and N-1 constraints, detailed operational and cost characteristics of generating units, including the ability of units to provide primary and secondary reserves. The electricity price and the value of individual resources should reflect these system constraints and location specific considerations.

The short-term planning model should be able to represent the market dynamics of power pools, single or multiple part auctions, market rules, bidding behaviors, etc. and the markets for reserve products. The market in Vietnam is new and will certainly evolve over the study horizon of PDP8. This will have significant impacts on the power system and must be captured in the PDP8 study.

### 3.2.7. RELIABILITY MODELING (PSS/E)

PSS/E provides analysis of the power transmission system. It requires significant input data on transmission nodes across the country. Once the generation planning is set, the transmission planners develop proposed investment programs to evaluate the power to the load centers and to plan for new interconnection to allow for planned import and export maximum transfer capacity levels. The planners check the proposed transmission expansion by running the PSS/E to ensure compliance with reliability standards. The expansion plan is updated with new/modified facilities if any of the standards were not met in their modeling. Once the plans are finalized, the investment requirements are calculated and included in PDP.

The PDP-7 methodologies did not consider secondary reserves (regulating reserves) in reliability analysis. Required levels of secondary reserves to manage system variability, as function of sub-hourly VRE and load variability, to 99.7% reliability targets should also be included in addition to primary reserves (contingency reserves) which protect the system against the outage of the largest on-line unit.

Transmission constraints (N-0, N-1, associated normal and emergency limits) must be carried out with respect to both static power flow (as in PSS/E) and the dynamic, hourly full year production simulation model (as is performed in PLEXOS and PROMOD).

Reliability should also be based on regulating reserve provision as well as contingency based reliability. Hourly production simulation modeling will determine if system resources can adequately provide both energy and reserves (primary and secondary) in a system co-optimization of energy and reserves, given energy and reserve shortage penalty prices.

Stochastic optimization might also be considered to more fully analyze system reliability. This might take the form of an LOLE stochastic Monte Carlo type analysis, as is performed in the PLEXOS Mid-Term module or the ABB E7 Portfolio Optimization module. These models consider thousands of statistical draws of system load, generation outages, reserves, and transmission availability to develop statistical distributions the ability of the system to serve load.

Stochastic optimization can also be used as an alternative to scenario analysis to represent system characteristics such as hydro conditions, load, VER generation, and others. Stochastic optimization can be used in both long term and short-term analysis, to find the best long-term expansion or the best short-term unit commitment and dispatch that is optimal with respect to uncertainty, as explicitly represented via probability distributions. PLEXOS and PROMOD both have stochastic optimization capability.

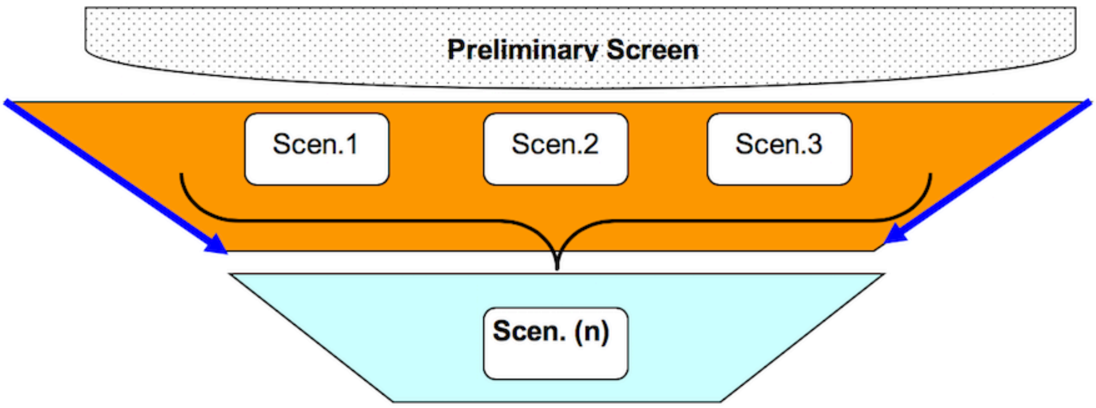
### 3.2.8. Scenario Development and Sensitivity Analysis

Comparative analysis of the scenarios is carried out based on making optional scenarios by changing of inputs according to subjective factors: Power demand scenarios (low, base and high demand); Increase and decrease of renewable energy share…with the objective factors given: ability to supply coal, gas and coal price, gas price, electricity import situations. Scenario has the lowest cost, the most reliable and feasible will be selected and recommended.

Detailed scenario simulations of the optimization results were conducted in PDP-7:

- Three scenarios with the base load forecast and two scenarios with the high load demand forecast that are included in the comparative calculation.
- The scenarios were put in the simulation of the optimization program to calculate of investment costs, fuel costs, purchasing costs, exchange costs on the 500kV North –Center – South tie line.
- Total current cost and net present value of scenarios were compared.

***Figure 22: Description of the source alternatives***




*Source: IEVN*

**Assessment**

Scenarios must go beyond demand and generation analysis. The process of developing and analyzing scenarios should be continued and expanded into risk analysis. The risks in the sector are commonly known

1) **Demand growth** – larger than expected in PDP-6 and smaller than forecasted in PDP-7, but must include the impacts on tariffs – both higher and lower demand than forecasted can result in tariffs
2) **Slow development of selected generation projects** – delays in the contract negotiation and permitting process
3) **Financing of project** – lack of contract or regulatory framework acceptable to international financing institutions resulting in delays or cancellation of projects

4) **Neighboring country generation projects** – some projects construction is delayed or canceled and likewise for interconnections.
5) **Fuel price and availability** – gas field development, the price and availability of LNG, and the price of imported coal creates uncertainty about which carbon fuel to select
6) **Technology change** – technology is increasingly moving toward the customer which could have major impacts on the need of services provided from the grid

These risks must be analyzed through scenario analysis. The output of the analysis should the economic and technical impacts and the planners should develop a list of risk mitigation measures that are triggered when certain conditions in the sector exist.

The development of the competitive market will increase the uncertainty of what type of generation will be built and where. Different scenarios will need to be assessed so that the implications of different future trends can be examined and mitigating actions when the future does not take the expected path.

### 3.2.9. Modeling Tools used for PDP-7/RPDP-7

#### Modelling tools

The following software models were used in the analyses leading to PDP-7 and RPDP-7.

**PDPAT-II**

The Power Development Assistant Tool (PDPAT) is a power generation planning software developed by Tokyo Electric Power Company, Japan (TEPCO), provided through technical assistance to Vietnam in 2003. The optimization method uses the Lagrange uncertainty factor to calculate generation production levels so that the fuel cost is minimized (optimal operation).

PDPAT calculates the simulation of the entire power system's power source combination, including multiple interconnected subsystems (up to 10 subsystems) by transmission lines. When the planner identifies alternate scenarios of development in the objectives year, the program has the following functions:

- Calculation of the ability to meet the load requirements of the system with each of the safety criteria provided, i.e. calculate the required reserve of each connected subsystem as well as the entire system to ensure safety power supply with an expectation of power failure in a given time (LOLE-Loss of Load Expectation). In case one of the subsystems does not guarantee reserve capacity to provide secure load demand in the area, the amount of power transferred from neighbor subsystem will be calculated to support.
- Based on demand forecasting and one of the options for developing of generation sources, the program calculates the mobilization of power plants and transmission lines linking subsystems to simulate the optimal operations; calculate the required fuel of the subsystems; Compare the fuel cost of the subsystem as well as the associated system to find the most economical generation dispatch of the entire system; Then aggregate fixed costs, fuel costs and power exchange costs to calculate the annual aggregate cost, determine the economic efficiency of the generation planning option.
- By considering the annual cost computations of different generation development options under the steps, the planners can find the optimal combination of generation development plan, considering the effectiveness of the tie lines.
- The advantage of PDPAT is that it can simulate multiple sub-systems, effectively calculating the sharing of reliability and economic efficiency of power exchanges between subsystems,

the tie line size. The disadvantage of the PDPAT is that it does not itself create alternatives to optimize the power development program.

- In 2004, EVN purchased STRATEGIST program and provided it to the subsidiary planning and operating units such as the IE and NLDC. STRATEGIST has a similar approach like WASP: This is an optimal dynamic planning program. The objective function is to determine least cost generation dispatch with given constraints. STRATEGIST can simulate an electrical system of interconnected subsystems, which considers the efficiency of energy exchange when mobilizing the economy of power supplies, and the sharing backup capacity.

**Strategist**

STRATEGIST program used in Vietnam includes 3 important modules are:

- Load Forecast Adjustment Module (LFA): Describes load demand forecasts by customer type, customer group, typical load shape of customer type, and load factor. In addition, in combination with several other modules (GAF, FIR, CER), it also calculates elasticity of demand, and serving DSM programs. LFA represents the "demand" side in optimal programmatic computing.
- Generation and Fuel Module (GAF): a detailed simulation of technical economic, financial and performance indicators of all power generators in the subsystems; Simulates the fuel used, fuel price, hydrological conditions of hydropower projects, the technical and economics characteristics of timelines and other aspects. GAF is the representative of the full simulation of the "supply" in the optimization problem.
- The PROVIEW module (PRV) is a dynamic program. Similarly, to the WASP program, PROVIEW sets and solves the optimal long-term generation expansion problem according to the Bellman optimal principle as well as consider the benefits of exchanging energy between sub systems.

STRATEGIST can simulate up to 15 connected sub-systems, exchanging energy with neighboring sub-systems.

At present, some countries in the ASEAN region also use STRATEGIST in the planning program of power development.

**PSS/E:**

During the PDP-7 and RPDP-7 power grid development program, IEVN used PSS/E (Power System Simulator for Engineering) program developed by Siemens. The PSS/E program is used to study transmission systems, to calculate the load flow, and to analyze the dynamic stability of the electrical grid system. The PSS/E program also allows the identification of short circuit currents (1 and 3 phase) at all nodes in the electrical system.

The approach and work flow that were used in previous PDP work were based on the tools that were used. They may have been good choices at the time but are inadequate for use in PDP-8. Today, short term models, or operations models, are available and widely used in power system planning. Such tools are necessary to capture and evaluate system performance, and possible issues, at the hourly, and even sub-hourly level.

The ability, or inability, of traditional generation resources (thermal, hydro) to meet demand and reliability requirements, must be evaluated at these levels to ensure, for example, that plans formulated using long term approaches, are feasible and optimal at the operations level. The need increases when considering RE resources, as their sub-hourly fluctuations, together with the fluctuations of demand, may impose additional challenges for the system. All these options need to also be evaluated based on location on the transmission grid (i.e., nodal analysis) to ensure the transmission grid can reliably deliver the power, and to evaluate transmission alternatives.

Newer technologies (e.g., smart grid, DR/DSM, energy storage, EV) need to be studied in detail (time and space) to properly evaluate their benefits, costs and challenges. The use of the short term (operations) model, with hourly/sub-hourly analysis and a nodal representation, implies significant changes in the PDP methodology, as described below. Note that the approach described here is based on the discussion on International Leading Practices and what is proposed in Figure 24.

The collection and preparation of data for the PDP-8 process will differ from previous PDP work due to the use of the newer tools in general, the addition of the operations model and the availability of data today that was not available in earlier years. Other, and relatively recent, planning studies should be made available for PDP-8 process, so that their results and lessons can be leveraged in the PDP-8 process. To the extent some of the information below has already been collected, perhaps for use in other studies, is relatively current and is readily available, it should be reviewed and used for the PDP-8 process. Note that based on the findings from the Mission in August 2018, it is felt that most, if not all, of this data is available.

In what follows, there are observations regarding the methodology used for PDP-7 and RPDP-7, and the associated inadequacies, if it were to be applied to the PDP-8.

### Modeling Methodology and Tools

With PDP-6, PDP-7 and RPDP-7, the power generation development program also chooses the methodology: "Least cost planning" using dynamic programming to solve the optimal development program, but there are some improvements. The improvement and implementation in the methodology of generation planning was to solve the optimal planning of balanced source development on each subsystem, considering the efficiency and limitations of the tie lines, and to ensure safe and reliable power supply on each substation and nationwide.

In PDP-7 and RPDP-7, the power development program is implemented by solving the least cost of system, using the STRATEGIST and PDPAT II planning calculations.

- The results from the STRATEGIST allow to determine the optimal amount of generation plants in the planning period in the form of fuels: hydropower, pump storage, coal thermal power, gas and oil thermal power plants, singer gas turbines. combined cycle gas, nuclear power, renewable energy (wind power, small hydro, biomass, etc.); by unit capacity; by location of the North, Central and South.
- When the optimum solution of the fuel mix in the generation expansion is achieved (as the base case), the re-simulation of the fuel mix in the process of mobilizing the hydroelectric and thermal power plants is carried out by the PDPAT program. It shows the real-time operation of power plants. It is possible to study several different options, including interventions such as policies to increase the share of renewable energy sources, or increase nuclear power capacity. Comparing the total cost of the given options will support the planner the consideration of the advantage and disadvantage of the policy.

The approach apparently used manual iteration between the solutions. Because of the complexity of inter-temporal constraints and operations, such as with hydro scheduling, the means and methodology in which the long and medium-term solutions for water or fuel allocation is based and used by the short-term solution can have a meaningful impact on the feasibility and costs of the solutions.

In modern planning systems, Mixed Integer Programming has replaced the use of dynamic programming or Lagrangian-Relaxation of integer constraints for modeling unit commitment and dispatch. This is particularly important when integer decision having large cost impacts – such as the commitment of coal units – is present in the system, as in Vietnam. The older models described in the current approach section take many shortcuts when it comes to unit commitment.

The use of typical week, typical day, etc., as described in the current approach is not required and, in fact, should be avoided with today's tools and methods. Though it may have saved some computing resources (CPU time, computer memory), today's tools and computing resources do not need such shortcuts. More importantly, using such approaches incorrectly eliminates challenging conditions, which often occur repeatedly, by smoothing over them, or skipping them altogether depending on the averaging or sampling techniques that are being used. These may be, for example, conditions when demand is changing rapidly, availability of RE is changing rapidly (increasing/decreasing wind and solar), generation constraints, transmission constraints. Instead, today's tools can, and must be required to, analyze 8760 hours (full years) in chronological manner, like the way NLDC must operate through the year. The models should use full nodal transmission models with SCUC, SCED, and N-0/N-1 constraints for the full year of system operations to most accurately represent system operations.

Modeling capabilities should be upgraded for application in PDP8 to a system such as PLEXOS or ABB E7. Modern planning tools such as PLEXOS and ABB E7 have fully integrated these capabilities into common platforms, using sophisticated methodologies and algorithms to coordinate the longer term and short term planning models and allowing for a rich representation of nodal constraints, reserve requirements, co-optimization of reserves, power markets, etc. It is recommended that such integrated planning systems be used, rather than employing ad-hoc integration of separate tools. Doing so will avoid inconsistencies in inputs, assumptions and methodologies. It also reduces the burden on the system planners in trying to correctly coordinate inputs for different tools.

**Hydro Modeling**

Hydrological probability conditions are taken at 90% (dry year), 75%, 50% (average year) and 10% (wet year) with corresponding weights 0.15; 0.25; 0.50; 0.1 to calculate energy security in case of dry year, using the annual average frequency of water 50% to compare economic and technical alternatives.

Since most large and medium-sized hydropower projects have been included in the PDP-6, PDP-7 and RPDP-7 and the process was to mainly review and analyze changes and updates on the implementation of these hydropower projects. No need to rank hydropower plants at the investment cost.

PDP-7 and RPDP-7 synthesized the previous pump storage studies and analyzed them and considered the potential pump storage projects in generation expansion plan.

PDP-7 and RPDP-7 planners collected the statistics and assessments of small hydropower projects nationwide, by regions and incorporated them into PDP following renewable energy objectives.

While additional future hydro resource potential is limited in Vietnam, hydro energy remains a significant energy and reserve resource in the system. As such, it may be important to deploy detailed production simulation systems that model such aspects as reserve provision, cascaded hydro, hydro constraints (such as minimum flow limits, multi-use aspects, environmental considerations) and generator efficiency as a function of head storage to accurately represent the operation of hydro. These may become even more crucial as hydro is used to support RE. Please refer to the international examples section for relevant examples.

**Reserves**

The only assessment of reserves in PDP-7 seem to be in the context of gross planning reserve capacity calculated as the difference of system peak load and generation capacity not including VRE.

As discussed earlier, both primary reserves (contingency reserves) and secondary reserves (regulating reserves to manage net-load variability) should be quantified / calculated, and energy and reserves should be co-optimized by a production simulation system in an hourly system model, under N-1 transmission contingency conditions.

With regard to planning reserves, the capacity value of VREs might also be taken into consideration; however, since there is a surplus of planning reserves, this may not be required.

#### Overall Assessment of Existing PDP Software Models

The modeling tools that were used in previous PDP work may have been good choices in the past, but are now several years old, out of date and likely not currently licensed. If the tools do not have a current license, current licenses must be updated. Regardless, the previous tools are no longer supported by their vendors. Current versions of tools can efficiently model much more and, varying by tool, have support available. While working on PDP-8, should an issue arise when using a current tool, the vendor could answer questions and, if needed, provide an updated version of the tool. For PDP-8, new tools will have to be selected.

### 3.2.10. Modelling Tools to be Considered for PDP Works

This section assesses capabilities critical to the PDP-8 process and the Vietnam power system.

**ABB E7**

**Advantages**

- Industry standard tool used in several large US markets and globally
- Extensive current validated US based databases
- Components can be licensed individually or as a platform
- Support and training available through ABB
- Used in official, and sometimes adversarial proceedings. The model has been well tested in challenging situations
- The various components share the same input database, allowing for ease of use and consistent inputs to the various components
- Capabilities include strong unit commitment and dispatch, cascaded hydro, operating reserves, power markets, nodal capabilities
- EVN has a license for components of the suite.

**Disadvantages**

- High licensing fee

- Some features of modules are legacy systems that have been incrementally upgraded and may not fully represent state of the art methodologies and algorithms
- Some of the features are very new and may not be as well tested as the older components.

### PLEXOS

**Advantages**

- Detailed and sophisticated hydro modeling, including generator efficiency as a function of storage level and cascaded hydro
- Fully integrated Long Term, Medium Term, and Short-Term planning
- Since PLEXOS is one tool, there is no issue regarding coordinating input data between models.
- PLEXOS is a relatively new product, and as such the system has been designed up-front with state-of-the-art methodologies and algorithms, without relying on outdated legacy tools.
- Strong user support and training through PLEXOS
- Developers are responsive to user input and discovery of system issues / errors
- Used in official, and sometimes adversarial proceedings. The model has been well tested in challenging situations.
- PLEXOS can model the gas pipeline network, which may be useful in modeling associated pipeline (gas delivery) constraints
- Capabilities include strong unit commitment and dispatch, co-optimization of operating reserves, power markets, nodal capabilities
- ERAV and EVN (and maybe others) have had recent experience with PLEXOS. However, given the time limitation of the PDP process, the staff in charge may experience difficulties at the beginning of the learning curve and need further support by international experts e.g. NREL. Copies of their databases may be available to help jumpstart the PDP process. The data should be independently validated.

**Disadvantages**

- PLEXOS LT has several shortcomings with regards to its treatment of wind and solar (e.g., undervalues RE and tends to optimize CAPEX over OPEX; cannot set generation targets but capacity targets; and ineffective in evaluating policy impacts.)
- LT, MT and ST modules must be licensed as a full system. By this, the flexibility in connecting with other planning tools may be lowered, however this may not be a disadvantage if the user needs all the models.

### Balmorel

**Advantages**

- Transparent model formulation
- Flexibility in model formulation
- Wide adoption in academic and other research institutions

**Disadvantages**

- Capacity expansion only
- Expansion optimization done one year at the time not for the entire planning horizon
- Users must learn modeling language and develop a high degree of expertise to run the system

- GAMS is a general optimization framework, so that the algorithms are not customized or specialized to the specific model formulation, as is typically the case in commercial models. This may affect model run-time or even the capability to solve certain problem formulations
- Limited use in official, adversarial proceedings.[10]

### PDPAT

**Advantages**

- No licensing fee with international development support from Japan

**Disadvantages**

- Capacity expansion only, limited operational system capability
- Not a commercially licensed product, so used only with support of Japan and TEPCO
- Limited use in official, adversarial proceedings outside of Japan.

### Markal/Times

**Advantages**

- Wide global use for energy, not just electricity, sector studies
- No licensing fee, although GAMS and optimizers must be acquired with an annual or perpetual license

**Disadvantages**

- Significant training and effort required to learn modeling language and to develop models
- Limited or no support from commercial vendors
- Capacity expansion only
- Limited use in official, adversarial proceedings

[10] It is worth to mention that the Danish Energy Agency is supporting MOIT on Balmorel modeling in Vietnam and develops Vietnam Energy Sector Outlooks using the tool.

Table 5 below summarizes the applicability of those models being considered for future PDP works.

*Table 5: Summary of Model Capabilities and Cost*

| Model | Capacity Expansion | Reliability, LOLE Calculations | Security Constrained Unit Commitment with N-1 Contingency Analysis | Integrated Platform for Long, Medium and Short Term Planning | Co-Optimization of Energy and Reserves | Cascade Hydro Modeling | Power Markets |
|---|---|---|---|---|---|---|---|
| ABB | X | X | X | X | X | X | X |
| PLEXOS | X | X | X | X | X | X | X |
| Balmorel | X | | | | | | |
| PDPAT | X | X | | | | | |
| MARKAL/TIMES | X | | | | | | |

## Costs for Acquiring Modelling Tools

As previously mentioned, the PDP results are critical in that they provide information that will be used to make decisions that have large impacts (financial, environmental, social, etc.) for the country, and the region. The software costs (see Table 6) are insignificant in comparison with the consequences of the PDP.

*Table 6: Estimation of Model Costs*

| Model | User Interface | Commercial Product | Technical Support | Cost per license[11] |
|---|---|---|---|---|
| ABB | X | X | X | $150,000, 3 licenses minimum |
| PLEXOS | X | X | X | $82,000 |
| Balmorel | | | | Free, $20,000 GAMS license |
| PDPAT | X | | | Free |
| MARKAL/ TIMES | | | | Free, $20,000 GAMS license |

As indicated above, the costs are per license. Use on a single CPU utilizes one license. Typically, multiple licenses are obtained. This allows for work to be performed on the multiple CPUs of a single PC and/or to spread workload across multiple PCs. The commercial packages have tools to help manage the distribution of the workload (e.g., keeping track of which runs are currently running on which PCs and launching new runs as soon as old ones finish). Of course, it may be quite useful to allow for multiple users to use the models simultaneously, which would also require multiple licenses.

A more realistic comparison of license costs would be for a 3-license setup. As indicated in the table, this is the minimum requirement for ABB at approximately $150,000 per year. For a 3-license installation, the annual fee for PLEXOS is estimated at $120,000 per year.

[11] Pricing is in USD and indicative. Pricing may vary by region (Asia, North America, etc.) and may have some room for negotiation. Pricing is also based on options likely to be needed. Some options are dependent on IT configuration.

### PSS®E Models and Licensing Costs

The current version of PSS®E is 34.4, with the possibility of a newer one before work starts on PDP-8. The version currently in use in Vietnam is the one that was used for earlier PDP work and is several years old. Before starting work on PDP-8, a current version of PSS®E should be obtained. The table below provides monthly license fees for a few different configurations. For purposes of the PDP, the *Base + Short Circuit + Dynamics Module* should be obtained, at annual cost of $30,000 per license. Though not as computationally intense as some of the other models, to allow for multiple users to simultaneously use PSS®E, it may be useful to obtain multiple licenses of the model.

***Table 7: PSS®E Monthly License Fees***

| Modules | Monthly License Fee |
|---|---|
| Base Model | 1370 |
| Base + Dynamics Module | 2055 |
| Base + Short Circuit + Dynamics + OPF Module | 3184 |
| Base + Short Circuit + Dynamics Module | 2500 |
| Base + Short Circuit Module | 1815 |

## 3.3. KEY FINDINGS

The PDP methodology used for previous PDPs may have been fine at the time but is inadequate for PDP-8. The methodology does not do a thorough enough analysis of how the system can, or cannot, operate. The operations analysis tests the feasibility of the expansion plans proposed by the long-term model. The long-term model, with today's computing power, makes simplifying assumptions to produce an optimized, least cost plan over the 10 to 30-year time horizon. The operations analysis allows for an essential step, the testing of the feasibility of the long-term plan.

Most international examples presented earlier, are examples from PDP type planning exercises from other countries. In those studies, the operations analysis often found issues with the initial plan from the long-term model. There are many detailed issues which are not captured in long term models that must be considered simultaneously to evaluate feasibility and refine the optimization. Using the results from the operations analysis, adjustments were made to the long-term analysis and results were obtained through an iterative process. Some of the issues that are simplified or skipped altogether, in long term models, especially those that need to be captured in PDP8, include:

- **Time**: To analyze longer time periods, long term models make simplifications in the way they handle time. Simplifications include using an LDC approach; using larger time steps (multi-hour time steps, variable multi-hour time steps); sample/typical week approach, or similar, where a week is simulated and the results are scaled up to represent the month. Naturally, many details of the power system that occur on the time scale of minutes to an hour or so, are missed. Though it may seem like a sample week approach will solve this issue, it still has limitations in that the variability that exist across all the minutes and hours of the month in the load, weather, VRE patterns, etc. are lost. Also lost are the longer time constant characteristics of generators, such as base load units with many hours to multi-day dynamic characteristics, long outages, etc.

- Unit commitment and dispatch: Simplifications to unit commitment and dispatch algorithms, ignoring some constraints, which lead to inaccuracies in results. Of course, these simplifications may make some sense if a detailed chronological simulation is not being performed, as mentioned in the first bullet.
- Space: To manage the computational burden, the details of the transmission system are not included, in favor of representations using a few zones where transmission is ignored inside the zones (copper-plate assumption) and transport logic is used between the zones.
- **Cascaded Hydro**: Representation of reservoirs, reservoir levels, the impacts of the latter on other characteristics, waterways, evaporation, etc. are usually ignored or greatly simplified in long term models.
- **Power Markets**: The detailed aspects of power markets such as their rules and bidding behaviors are often skipped. In such situations, one might argue they are representing a perfect market. Of course, a perfect market does not exist.
- **Operating reserves**: The various operating reserves are usually not represented, much less part of the optimization process, in long term models.
- **VRE, DR/DSM, EVs, energy storage**: Due to algorithmic simplifications and simplifying assumptions, VRE, DR/DSM, EVs and the like cannot be analyzed in appropriate detail in long term models.

All the above are important in Vietnam's grid today or are likely to be important in the coming years. As such, it is essential the PDP methodology be able to capture all the above accurately, which can only be done with an operations model, together with a long-term model.

As discussed in the section on models the task of moving between different models can be made easier and less prone to error by using tools which share common databases. The task can be made even easier if the models are contained internally within the same model.

In addition to performing the operations modelling, the previous methodology is lacking in that it does not collect data necessary to setup the operations model. As discussed elsewhere, additional, often more detailed data will need to be collected and used not only for direct use in the operations model, but to improve the accuracy of the demand and transmission analysis steps.

The table below shows the differences between the PDP methodology used in Vietnam and the international leading PDP practices.

***Table 8: Comparing the PDP methodology used in Vietnam and the international leading PDP practices***

| | International leading practices | Methodology used for PDP7/RPDP7 | Remark |
|---|---|---|---|
| **Bottom-up load forecasting** | Yes | Limited | Unclear how to consolidate top-down and bottom-up results |
| **Generation costs** | Yes | Yes | |
| **Demand-side management options and costs** | Yes | No | Only national EE program (VNEEP) |
| **Transmission and distribution costs** | Yes | Limited | Only transmission (500 kV and 220/110 kV) |

| | International leading practices | Methodology used for PDP7/RPDP7 | Remark |
|---|---|---|---|
| **Risks of fuel price volatility, drought, carbon taxes, etc.** | Yes | Limited | Sensitivity analysis only with deterministic fuel costs |
| **Social and environmental “externality” costs** | Yes | Limited | Lack of country specific pollution generating factors |
| **Public involvement throughout process** | Yes | Limited | Draft PDP development report only, not during the process |
| **Scenario and sensitivity analysis to ensure “least-cost” under different cost or demand assumptions** | Yes | Limited | PDPAT II with typical day/week only |

Moreover, the regions to be analyzed in PDP should not be specified in legislation nor limited by previous studies. With the advent of the competitive market, new generation resources including distributed generation will impact the marginal cost of a region. That is, new regions will appear not because of physical congestion, but due to economic congestion. As part of the overall PDP process, the determination of regions should be completed once the marginal cost of generation across the country is determined. The payback on increasing transmission to relieve economic congestion will be part of the transmission analysis.

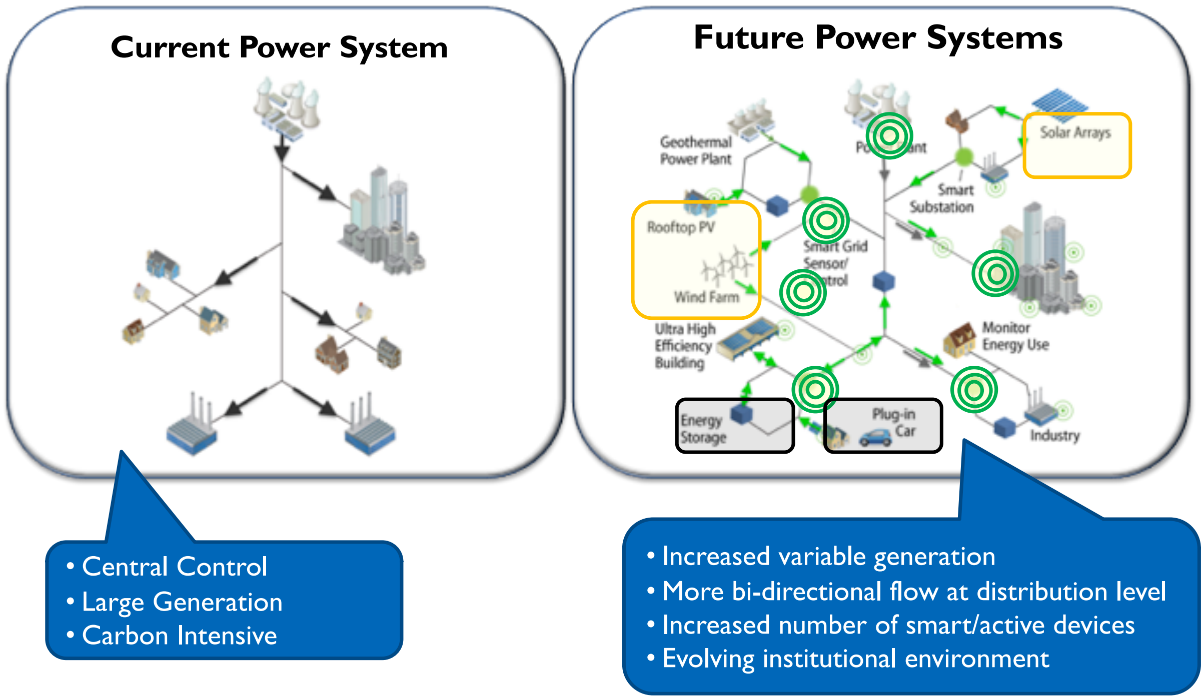
# SECTION 4: RECOMMENDATIONS

## 4.1. PLANNING FOR AN ADVANCED POWER SYSTEM: OPPORTUNITIES AND CHALLENGES

### 4.1.1. EVOLUTION OF MODERN POWER SYSTEMS REQUIRES NEW PDP APPROACH

In Vietnam, as is the case around the world, the power sector is poised for a rapid evolution. As illustrated in Figure 23, the traditional power system consists primarily of large, centralized, conventional resources that generate electricity that is delivered to end-users primarily via one-way flow through transmission and distribution infrastructure. A multitude of technological and market factors are driving a shift away from this paradigm toward modern systems that are more decentralized and in which end-users increasingly participate as suppliers as well as consumers of electricity through the adoption of decentralized generation, EVs, energy storage, and demand response.

*Figure 23. Evolution of Modern Power Systems*




*Source: Compiled by NREL*

Drivers that are likely to be relevant within the PDP-8 planning horizon include, among others:

- Rapid deployment of variable renewable energy resources (e.g., solar and wind) at both the utility-scale and distribution levels, driven by environmental goals and rapidly falling technology costs.
- Increased relevance and valuation of power system flexibility to manage more variability in electricity supply and demand.
- The potential for more bi-directional power flow at the distribution level, driven by end-user adoption of distributed generation (e.g., rooftop solar PV) and EVs.
- The proliferation of advanced energy technologies (e.g., smart grid, advanced inverters, advanced communication and control) that enable a variety of grid services from resources

that have not historically provided them (e.g., variable renewable energy and load) and two-way communication among suppliers, transmitters, and consumers of electricity.

- Evolving institutional contexts, most notably, the development and implementation of Vietnam's power market.
- Falling costs of energy storage.
- Complexity and implications of policy driven targets (e.g. RPS).
- Evolving objectives related to resource adequacy, reliability, and reserve margin (planning and operational), especially in the context of improving the resilience of the power system to natural and man-made threats.
- Improved understanding of potential roles for microgrids, mini-grids, and off-grid systems.
- Increased potential for demand side resources to modify future load shapes and requirements, allowing planners to consider the role of DR, EE, and DSM in contributing to a least-cost power system.

This evolution has the potential to bring many benefits, including fewer negative environmental impacts, lower-cost electricity supply, and better reliability and electrification. However, it also poses challenges, particularly for planners tasked with anticipating the magnitude and timing of these changes. In this context, a key objective of power development planning is to explicitly value supply and demand side options from a power systems perspective with respect to detailed operational and transmission constraints of the system.

As discussed above, the importance of the PDP, in terms of the magnitude, time, costs, impacts, etc. of infrastructure projects is tremendous and dwarfs the effort, cost and time associated with the PDP study itself. Vietnam is hoping to attract more outside investment in the power sector. This would likely be in the form of investment in generation (e.g., IPPs). To attract such interest, it will be essential that the PDP is done properly, as recommended in this report. The use of improper methods, shortcuts, old or improper tools, etc., will almost certainly impact the level of confidence that such investors have in the sector, and may be a factor in them choosing to invest in projects outside of Vietnam.

### 4.1.2. Key Objective: Updating PDP Methodologies to Plan for Higher Levels of Variable Renewable Energy

The Government of Vietnam (GVN) updates its PDPs and regulations (e.g., grid codes) on a regular basis. However, with a growing queue of solar and wind energy project proposals, Vietnam's power sector planners have articulated major concern about the capability of the power system to absorb high variable RE penetration levels without experiencing significant operational or reliability challenges. Another challenge would be the uncertainty of resources available/committed for power system expansion. It is essential that the new PDP process use state of the art methods, practices and tools, but also adopting/re-using the robust PDP process and capacity expansion models being developed through previous efforts. The development of PDP-8 can also leverage other planning expertise and models that have not historically been explicitly linked to the PDP process. For instance, both ERAV and EVN-NLDC already utilize production cost modeling software to conduct short-term planning. These models can be adapted to facilitate operational analysis within PDP8.

As the proportion of variable RE in the electricity generation mix increases, traditional power planning processes evolve to take into consideration the unique characteristics (such as variability, uncertainty, and locational specificity) of solar and wind energy (Milligan and Katz 2016). Key changes for power system planning for higher levels of variable RE include:

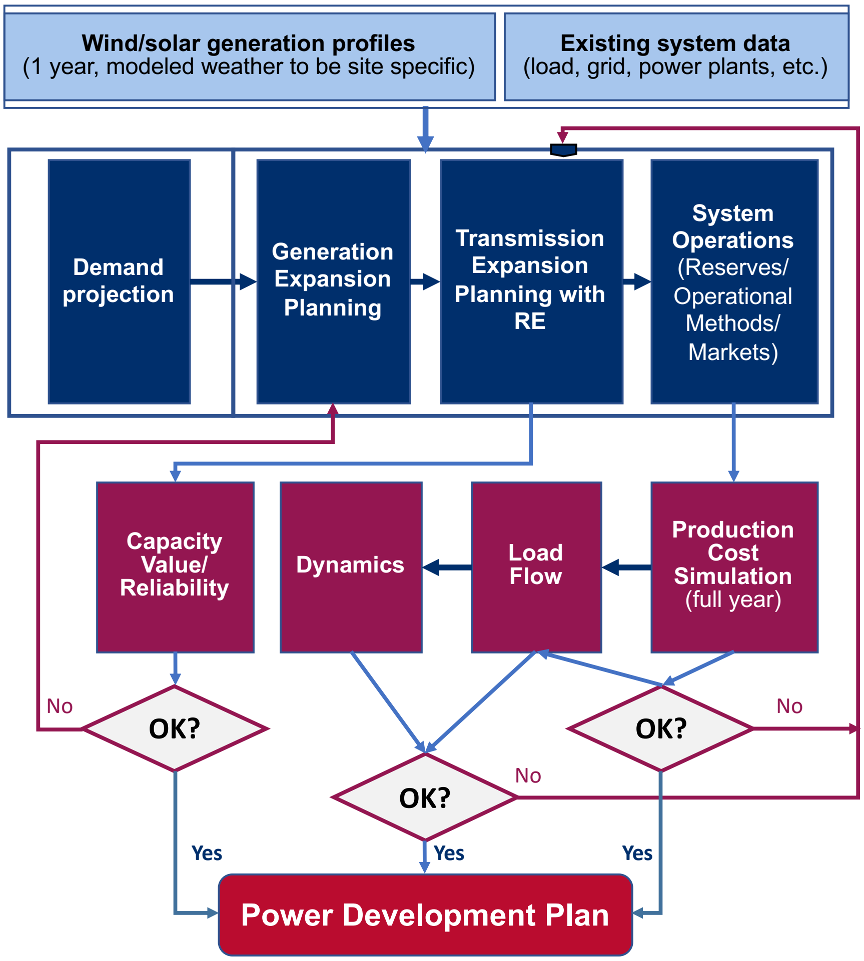
- The need for input data that characterize the hourly or sub-hourly solar and wind generation at high spatial resolution;
- Consideration of solar and wind resource potential and geographic concentration in transmission planning; and
- The need for operational modeling (i.e., production cost simulations) that covers every period (e.g., hour, 30-minute increment) of the year, rather than only example days or weeks.

The proposed methodology discussed in the following sections reflects these changes and can also help MOIT and its partners to address their fundamental question regarding the appropriate share of variable RE in PDP-8. With regard to modeling tools, as discussed in Section 3.2.10, each model has its advantages and disadvantages and therefore no single model is truly capable of *optimizing* the level of solar and wind in the power mix based on both fixed costs and operational considerations. Further, neither grid integration studies nor actual operational experience have yet found a physical limit to variable RE penetration in any given power system. As RE increases, system operators and planners have many options to address reliability – some no-cost, some through new infrastructure. Thus, a comprehensive PDP methodology should consider using multiple models to explore potential cost, operational, and reliability tradeoffs that might arise at different target levels of variable RE on Vietnam's power system. The methodology will also address how different flexibility solutions can help cost-effectively mitigate challenges that arise.

## 4.2. NEW APPROACH FOR POWER DEVELOPMENT PLANNING IN VIETNAM

The general approach to power system planning can be thought of as shown in Figure 24. The reader is cautioned that the actual study process is more complex than can be depicted in such a diagram. For example, intermediate findings at any point, even part way through a particular block, may cause the study to move back to an intermediate point in any of the previous blocks. Similarly, steps may be skipped, based on intermediate results.

*Figure 24: Recommended PDP Approach/Methodology*




*Source: Elaborated by NREL*

The sections below describe each of the major components in Figure 24 in more detail.

### 4.2.1. Data Collection

The planning process is a data-intensive exercise relying on information from many different sources. The collection and preparation of data for the PDP8 process will differ from previous PDP work due to the addition of the use of the newer tools in general, the addition of the operations model, and the availability of data today that was not available in earlier years. Good practices for data collection to inform each step of the power development planning process are discussed in Section 2.3. Based on key findings from the Mission in August 2018, it is felt that most, if not all, of this data is available in Vietnam to support the development of PDP-8, including

- *Detailed historic electricity demand (e.g., hourly or sub-hourly, disaggregated by region or node);*
- *Detailed datasets representing the existing and planned generator fleet and transmission and distribution network characteristics and costs;*
- *High-resolution solar and wind datasets (hourly or sub-hourly, with national coverage at a high spatial resolution); and*
- *Geospatial data layers representing land cover, protected areas, slope, and other characteristics that can be used to screen sites for potential solar and wind power plant*

As illustrated in Table 3 and detailed in Section 2.3, two general types of data lay the foundation for the proposed new approach to PDP planning:

**1) Renewable energy generation profiles**. The use of high spatial and temporal resolution solar and wind energy generation data (i.e., modeled, gridded hourly or 30-minute time series) represents a significant new element of the proposed PDP process and will enable the PDP to better identify challenges and opportunities related to integrating variable renewable energy to the power system. In recent years, MOIT has worked with the World Bank, GIZ, and others to improve the solar and wind resource data for Vietnam. The data produced through these efforts likely can be leveraged for use in the PDP analyses, though additional processing may be needed to screen suitable areas for development (e.g., based on updated information related to land use, terrain, and other factors) and create generation profiles based on modern solar and wind energy technologies. If existing datasets are inadequate, high resolution, modeled solar and wind resource datasets are available for purchase from a variety of vendors. Given that off-shore wind is an option, information on off-shore wind-power potential must be collected.

**2) Existing system data** (at a minimum, one recent historic year of detailed demand, generator, network, and operational data). Much of these data are likely to be available from other, and relatively recent, planning studies. For example, stakeholder consultations conducted by the V-LEEP team indicate that EVN-NLDC uses operational and transmission planning models such as PLEXOS, PROMOD, and PSS®E, which will include much of the data listed in Section 2.3. Exploring options to use the data in these existing models—and supplementing them to fill gaps as needed—will improve the efficiency and accuracy of the data collection process for PDP-8.

The PDP process must determine:

1) the information is needed, both for overall assessment, resource screening, and system modeling
2) the data is available from previous PDPs, from the sector and from the numerous IFI and donor-funded studies
3) the data gaps when comparing 1) above to 2) and laying out a plan to collect that data for future PDPs
4) the data for quality, consistency and sufficient quantity (for example, one or two regions rather than nationally) and developing a plan for improving the existing data

A central database with all the planning data and information should be maintained and updated on a regular, if not constant, basis.

### 4.2.2. Demand Forecasting

***Output:* future load magnitude and profile, disaggregated spatially (e.g., by node) and temporally (e.g., hourly or subhourly)**

A hybrid demand forecasting approach, combining a top-down and bottom-up approach will be needed for PDP-8. The top-down (conforming load) analysis will be similar to the process used in PDP-7/RPDP-7. Historical load shape data, combined with socio-economic and demographic data and forecasts, will be used as a basis for forecasting the conforming load. The latter will include information segregated by customer type (residential, commercial and industrial), by sector (agriculture, transport sectors, mining, manufacturing, street lighting, etc.) and by region (north, central and south).

Unlike previous PDPs, the demand forecast in PDP-8 will have to deal with greater details of regional load profiles – including more regions for allocating to the transmission nodes of the system, at an hourly or sub-hourly level (load profiles with high temporal resolution are essential inputs to operational models and renewable energy grid integration studies, which test the feasibility of balancing electricity supply and demand at every dispatch interval of the target year). As Vietnam has already achieved a high degree of electrification, there will likely not be a significant adjustment to the forecast to account for new electrification. Information regarding historical losses, and plans to reduce losses, will also need to be gathered and the forecast improved accordingly.

A new analytical element of PDP-8 is the addition of a bottom-up approach focusing on nonconforming load. The starting point for this will again be historical data at a granular level (time and location). Available information regarding specific demands (industrial parks, flagship projects, factories, ports, mines, agriculture, street lighting, electric trains, etc.) will be gathered. Additionally, information regarding new developments in each area, as well as changes to existing demand, will be gathered, reviewed and incorporated with historical data to develop this portion of the forecast. For example, with the increase in electric vehicle expansion, the demand patterns will be different and changing as car battery technology develops and the facilities for charging batteries develop. This bottom-up forecast will be combined with the top-down forecast to develop the overall forecasts.

Given the results of PDP-6 and PDP-7, actual demand can vary significantly from the forecast. From the historical review of those last two periods, scenarios must be built that can reflect possible futures where demand can be significantly lower demand and significantly higher, impacts can be measured and an PDP with flexibility to react to higher and lower with mitigating measures.

### 4.2.3. Demand-Side Resources

A key element of integrated planning is to ensure demand-side resources are treated on a level playing field with supply-side resources. In some countries, additional energy requirements are being satisfied only with implementation of demand-side programs and most likely there is a large potential for similar cost-effective programs in Vietnam. Those programs are quite specific with identified programs, the implementing parties, the cost of the programs, the impacts of the programs and specific actions to implement. Information on current and potential future EE/DSM programs will need to be gathered and incorporated in the forecast.

One of the real benefits of these resources is that they can be ramped up or ramped down from year to year to match the needs of the system. The higher growth in one region may require higher program levels in that region and less in other regions. This is incredible flexibility that is probably the best risk mitigation measure available to the planners and the sector management.

Demand response has become a power tool in mature power markets. Large customers can reduce their charges for generation capacity and transmission use-of-system by reducing their consumption or increasing self-generation at the time of the system peak. They also reduce the need for new generation and transmission, slowing the growth rate of retail tariffs for all consumers.

### 4.2.4. Long-term Capacity Expansion Analysis

***Outputs: future magnitude, type, and timing of installed generation and transmission capacity.***

### Generation expansion planning

Through the development of previous PDPs and other planning analyses, Vietnamese agencies have gained experience using generation capacity expansion models such as STRATEGIST and BALMOREL. For PDP-8, the general approach to long-term capacity expansion analysis will be largely like these previous efforts. The overall objective will be to simulate least-cost grid expansion decisions, looking over the entire 20-30 year time horizon.

The long-term capacity expansion model will be used to study the entire time horizon and, as a first pass, evaluate and make initial decisions about the expansion plan. To do so, current and accurate information on the existing system, as well as planned improvements (committed generation and transmission projects) will need to be gathered, reviewed and input in the model. The latter should include detailed technical characteristics (as detailed in Section 2.3). Information on candidate projects will also need to be gathered, reviewed and input into the model. The review process should ensure that timing and cost information includes not only the project itself, but infrastructure the project depends on (transmission, rail, road, ports, pipelines, land acquisition, permitting, time to collect resource data, project financing, environmental, etc.). For example, if a candidate coal plant can be built in four years, but it relies on imported coal which needs improvement to port facilities that require seven years and are specific to that coal plant, for purposes of the PDP analysis, the candidate coal plant should be considered available only after seven years and the cost of the improvements to the port should be included in the cost of the candidate coal plant. In this way, the long-term model can properly evaluate this option against alternative options. As appropriate, DR and energy storage projects, including their costs, time lines, technical characteristics will be input as candidates or committed projects to the model.

While the approach will be like that undertaken in previous efforts, PDP8 presents an opportunity for updates and innovation, including the following changes:

- **New model(s):** Consultations by the V-LEEP team indicate that the version of STRATEGIST utilized in PDP-7/RPDP-7 is out of date. Options for a new model are discussed in Section 4.2.8.
- **Higher resolution of the long-term model in time and space.** Section 4.2.9 discusses one possible approach to increasing the number of zones modeled in the PDP. In addition to increasing the spatial resolution, including more time slices in the capacity expansion model beyond one typical day or week will better capture the variability of both demand and supply (particularly variable renewable energy). This approach, enabled by the use of the high resolution demand and renewable energy resource data discussed in Section 4.2.1, can lead to more accurate representations of the contributions of variable renewable energy to firm capacity, among other benefits.
- **Updated technology cost and performance data.** The costs and performance characteristics of technologies such as solar PV, wind turbines, and battery energy storage have changed rapidly within the past decade. Updating cost and performance assumptions for all resources included in the capacity expansion model based on modern trends is crucial to developing a robust least-cost expansion plan.

### Transmission Planning

The starting point for transmission expansion planning in PDP-8 will be an accurate representation of today's grid, along with known plans for future years. For Vietnam, PSS®E cases representing every year through 2023, and then for 2025 and 2030, for on and off peak conditions for the rainy and dry seasons, exist today for use by EVN-NLDC. These cases represent an ideal starting point for transmission capacity expansion analysis, though they may need to be updated to reflect the latest available information. For example, the cases should be checked to ensure that they accurately reflect the status for all planned changes to the grid. Depending on the possible location of some new generation (e.g., wind and solar), the cases may need to be expanded to include portions of the 110 kV network that were not previously included. Additionally, information on capital and O&M costs for new (committed) and possible (candidate) transmission projects and timelines to reach COD should be collected. Transmission node location (e.g., latitude and longitude) also will be needed.

The feasibility of transmission expansion plans under different generation and demand scenarios will be tested via the system operations analysis and stability modeling discussed in the following sections. As needed, additional iterations of transmission capacity expansion analysis can be conducted to resolve problems that emerge in these other analyses.

### 4.2.5. System Operations Analysis (Production Cost Simulation)

***Outputs: operational metrics, including production costs and potential constraints associated with expansion scenarios, based on a full year of model results***

Operational analysis using a production cost model is the most significant new component proposed for PDP-8. PDP-7/RPDP-7 included limited operational analysis, evaluating operations only over a typical day or week to simplify calculations. In Vietnam and other countries, planners have traditionally considered capacity expansion in terms of the need for baseload, load-following, and peaking generation capacity, with respect to a given planning reserve margin, while transmission and distribution systems were designed to accommodate peak loads. This focus on peak load is changing as larger amounts of variable renewables are integrated into the grid. The new focus includes examining the need for increasing levels of flexibility and operating reserves outside of peak times, advancements in technology such as smart grids allow for more choices, demand response options as they become more prevalent, etc. In other words, various options can provide challenges and benefits away from the peak, which need to be evaluated. In addition, short-term variability (sub-hourly and hourly) in solar and wind energy generation should be accounted for, rather than relying on long-term average capacity factors. A failure to account for short term variability could lead to an inadequate or inefficient plan. Thus, it is no longer sufficient to consider only a few hours, snapshots, typical days/weeks; but it is necessary to evaluate all hours of the year, and likely to perform sub-hourly analysis.

For example, planning now needs to provide sufficient ramping capabilities, upward and downward, to meet fluctuating net loads[12]. Increasing the spatial and temporal resolution of power system models has become essential.

To better understand and plan for an evolving power system with variable demand and supply, PDP-8 can incorporate a new step to use a production cost model to simulate the operation of the power system during every period (e.g., hour, 30-minute, 5-minute increment) of one or more medium-term target years (e.g., 2030).[13] This step will have the important objective of validating the operational feasibility and operational costs of capacity expansion scenarios**.** Studies should model how all the identified portfolios from the capacity expansion analysis perform relative to possible futures. The exact target year(s) to be evaluated will be decided via stakeholder

[12] Net load is the total electric demand in the system minus wind and solar generation.

[13] This high-resolution model will be enabled by detailed demand and renewable energy data as well as data on the costs and physical characteristics of the system.

consultations. Ideally, the production cost model will be run to evaluate potential resource plans over at least several full years of the planning horizon, using scenarios over a range of hydrological, demand, fuel price, and variable resource profiles.

Hourly or sub-hourly production cost models more accurately reflect system operations and costs and can identify possible deviations from operational security requirements. A full transmission (nodal, rather than zonal) model will produce more accurate results if sufficient data are available to populate a nodal model.

Example areas of focus for operational modeling in Vietnam include:

- Evaluating feasibility, optimality and economics of long-term capacity expansion scenarios (mimic NLDC)
- Analyzing net load (total load minus solar and energy generation) variability
- Identifying areas of concern related to cascaded hydro (reservoirs, transit time, changes in characteristics due to varying level/head)
- Identifying operational opportunities related to cross-border trading
- "Periods of interest" for further study in stability or load flow models (e.g., low load/high RE; high load/low RE)

By modeling the dispatch (and curtailment) of all power plants, the operational model can also inform ***resource adequacy (capacity value) assessment***, which can be conducted within or outside of other integrated power system planning models.

There are concerns about the impacts on operations from existing BOT plants. With greater detailed operating models, the impacts can be measured, and feedback provided to the negotiators of new BOT contracts to eliminate any negative system impacts from their operations.

#### Renewable Energy Grid Integration Study

The use of a production cost model will also enable renewable energy grid integration studies. A renewable grid integration study is an analytical framework for evaluating a power system with high levels of variable RE resources. A renewable integration study simulates the hourly (or sub-hourly) operation of the power system under different variable RE penetration scenarios, identifies potential operational and reliability concerns, and determines the relative cost of actions to integrate variable RE. The results will address concerns from the policy, operational, and regulatory community about the operational feasibility of achieving higher shares of solar and wind power in the electricity mix and provide insights on cost-effective approaches to improving the flexibility of the power system.

A renewable energy grid integration study can be completed in conjunction with or after the finalization of PDP-8. Using the core scenario(s) for PDP-8 as a base case, a grid integration study would evaluate scenarios with even higher renewable energy penetrations (and/or for selected alternative years, e.g., average and extreme weather years). The evaluation of more extreme scenarios provides insights to near- to medium-term operations, efficient sources of power system flexibility, and contract considerations

### 4.2.6. Load Flow and Stability Analyses

***Output: reliability metrics***

The methods and models for conducting load flow and stability analyses in support of PDP-8 will be similar to those utilized in PDP-7/RPDP-7. PSS®E, an industry standard tool (which is popularly used in Vietnam), will be used to perform these studies (power flow, contingency, stability, short circuit and voltage studies). Additional follow-on assessments and studies ***may*** be required to ensure operability and reliability of high RE scenarios analyzed in the capacity expansion and operational model. For example, if the operations modeling finds instances when the RE generation is a large percentage of the total generation at specific instances/hours, the information from those specific instances may be loaded in PSS®E for further study.

Based on the results of the load flow and stability studies, additional iterations may be needed in the capacity expansion (generation and transmission) and operational modeling steps.

### 4.2.7. NATURAL GAS FACILITIES FOR POWER GENERATION TO REPLACE COAL DURING THE TRANSITION PERIOD

In the past, sector development plans (e.g., PDP and Gas Sector Master Plan) have provided the GDP growth path they would meet and the required investment as key decisional criteria. Policy analysis focused quantitatively (partial equilibrium) on the sector and anecdotal evidence was provided for macroeconomic indicators such as jobs and GDP.[14] This may have adequately served senior decision makers when the sector was subsidized, principally Government or donor financed, and when there were surpluses. Shortages were not assumed. Vietnam has entered a new era financing increasingly must come from the private sector and no major electricity sector investments have taken place recently. There will soon be shortages and these shortages will impact GDP, employment and exports.

Primary fuel analysis must be dynamic. The analysis should not just include the characteristics of the fuels, the forecasted price and suppliers. The analysis should include the value chain of fuel extraction and delivery to the power plants. Along each value chain, there will be the risk related to fuel availability/reliability, quality and price. The planners must think through the risks within these value chain and analyze the impact of the risk through scenario plan

Even though a plan for primary fuel delivery may have the least cost, that plan may have a very high risk related to price volatility or reliability of supply. A well-balanced portfolio of primary fuels, though it may have a somewhat higher cost, will provide risk mitigation and protection for electricity consumers from fuel interruptions and sudden market price increases. As an example, Norway in the late 1990s decided to retire their oil-fired generators with the increased generation projected from hydropower plants. But during a prolonged drought, the energy from hydropower plants was not sufficient to supply all the energy needed. The country requested that the private owners put the generators back on-line to cover the shortfall. This was a very expensive fix that could have been foreseen if the scenario analysis was performed. The oil-fired generators are now paid reserve capacity payments to keep them ready in the future when droughts occur.

The major overall challenges that need to be addressed in various time spans include:

- Geo-political risks associated with the development of new fields, given the geographic context of Vietnam's major deep-water fields that have the most promise;

[14] This is not meant to detract from the excellent work done in numerous policy analyses. It is just a statement that they need to be complemented by additional tools.

- The lack of specific incentives to develop small fields, marginal gas fields or full exploitation projects;
- The lack of incentives for the development of non-conventional gases;
- The lack of synchronous development of upstream, middle stream and downstream levels – absolutely required to derive the most from the gas value chain;
- The prolonged negotiation process for completing commercial agreements with the relevant stakeholders;
- Higher exploration & production costs and/or extended timeframe for technical feasibility and economic assessments of newly-identified fields, (some with low recoverable reserves, fields with high concentration of inert gases [i.e. Block B, Blue Whale, or smaller fields in the Southwest region], deep-water fields, or offshore fields much further out from the shore);
- Difficulties in properly identifying and estimating recoverable reserves due to the complex reservoir structures (examples, might be Thien Ung and Su Tu Trang fields);
- The lack of a comprehensive legal framework governing the gas sector. Currently, there seem to be contradictory or overlapping legal procedures and documents to cover the natural gas sector (Construction Law, Environment Law, and Investment Law) or no regulations to govern some activities. These shortcomings will adversely impact implementation efforts;
- Inadequate and distinct regulations governing LNG, especially about technical norms and standards, safety requirements during the process of LNG receipt, storage or regasification;
- Protracted and slow pace of negotiating PPAs with EVN, in approving or implementing imported LNG projects;
- A seemingly absent layer of detailed planning on LNG storage and related infrastructure facilities that address specific concerns in terms of scale, location, technical options) to ensure the efficient use of such infrastructure.

The natural gas industry is further expected to develop an overall gas market on the order of 23 – 31 billion cubic meters by the 2026 – 2035 period. The gas industry will be expected to undertake the following, on a regional basis:

For the Northern:

- study solutions to strengthen collection of gas from the dispersed small fields with an aim to strengthen gas supply potentials for industrial customers in the region;
- develop the required infrastructure for LNG imports to ensure gas supply capability within the region for industrial customers; and,
- build power plants using LNG in accordance with the Power Plans approved by the Prime Minister.

For the Central region:

- Develop the full infrastructure required for collection, transport and processing of gas from the Blue Whale field for gas-fired power plants in the region, again as per the Power Plans approved by the Prime Minister;
- develop a petrochemical industry based on feedstock from the Blue Whale field after ensuring full gas supply to the power plants;

- develop low pressure gas distribution system and produce CNG/LNG in appropriate sizes for supply to industrial customers in the region.

For the Southeast region:

- strengthen the exploration & production activities required for full gas-field development to meet gas demand in the region;
- fully develop port and storage systems for utilizing LNG imports to augment and/or supplant the depletion of domestic gas resources; and,
- supply gas-fired power plants in the region, again as per the PDP.

For the Southwest region:

- Upgrade the infrastructure for collection and transporting gas;
- build the required infrastructure system for LNG imports, to ensure gas supply for customers; and,
- develop new power plants using LNG.

Of course, this all assumes that investment will flow, and this assumes that the price for gas will be sufficient to cover new investments; something which has yet to materialize.

In the past, there was a Power Development Plan and a Gas Sector Master Plan but after 2017, the GSMP has been stopped and now the PDP output will drive gas sector investment planning. New considerations in planning are coming about. First, PDP VIII will seek to integrate renewables into the system in ways that will challenges conventional system operations and investment paradigms. To complement increased penetration of RE, the least cost method will most likely be gas power plants. Given that domestic gas can't respond quickly enough to bring new production on line in the areas it is most needed to avoid near term shortages, LNG is needed.

The GVN has a computable general equilibrium (CGE) model that it uses to conduct policy analysis in areas such as trade and GHG emissions. It could be enhanced to provide a full-blown detailed energy sector that would allow the Ministry of Planning and Investment (MPI) and the MOIT to jointly analyze the economy-wide impact of different retail electricity prices and of possible shortages. This information, the GDP, employment and exports, arising from different scenarios can only provide better information for senior decision makers.

Recommended scenarios to be evaluated under PDP-8 process include:

- Balancing high penetrations of variable renewable power with gas-fired reserves. Studies have shown that simple-cycle and flexible dispatch combined-cycle gas turbines are cost-effective sources of fast-responding reserves needed to integrate high penetrations of solar PV and wind power. The PDP-8 team should identify the quantity of fast-responding reserves needed for forecast variable renewable power capacity and identify gas investment needs.
- Price scenarios for imported natural gas. The PDP-8 team should develop a robust set of scenarios for future pricing of imported natural gas, which they can incorporate within production cost analysis for recommending future generation technology.
- Gas-for-coal thermal power substitution scenario. The revised PDP-7 projects a quadrupling of coal-fired power generation over the PDP-8 forecast period, from under 14 GW (2015) to almost 60 GW (2030). In its business-as-usual (BAU) scenario, coal-fired generation provides two-thirds of Vietnam's power generation in 2035 – and increases the carbon intensity of Vietnam's power sector by one-third. The PDP-8 team should establish a gas-for-coal thermal power substitution scenario. The team should apply this scenario to

the GSMP 2017 to identify incremental supply, transportation, and revenue requirements, including the need for additional LNG imports and changes in the projected cost of both gas and power. The team should highlight changes in gas industry investment requirements to realize this substitution scenario and impacts on other gas consumers in Vietnam.

- Retrofitting oil-fired power production for dual fuels. Vietnam still produces more than 900 MW of thermal power generation from oil-fired generation. Converting existing and new oil-fired generation to dual-fuel will open a new gas-to-power modality for Vietnam. The PDP-8 power planners should identify the additional gas supply required to substitute for existing oil-fired power production and identify the implications for the GSMP, including gas transportation requirements to existing oil-fired power plants.

### 4.2.8. MODELLING TOOLS

**Modelling tools for PDP**

The modeling tools that were used in previous PDP work may have been good choices in the past but are now several years old and out of date, and likely out of license. Current tools can efficiently model much more and, varying by tool, have support available (see Models section for details). The older tools have bugs that have since been fixed and new features. Due to the number of changes and enhancements, Strategist has recently been replaced by Capacity Expansion (NEW Strategist). PSS®E has undergone several improvements and bug fixes as well, with the current version being 34.4. While working on PDP-8, should an issue arise when using a current tool, the vendor could answer questions and, if needed, provide an updated version of the tool. If anyone were to question or challenge the results of PDP-8, one of their points would undoubtedly be to question the accuracy of the results due to the use of outdated software. For PDP-8, new tools will have to be selected.

Today's computers and models allow for a more sophisticated and precise level of analysis. We have performed this analysis in developing countries, where it is perhaps even more important than in developed countries to perform a thorough analysis as financial resources are limited and the impact of an error in the analysis can have a significant impact. At the same time, we have performed this analysis in developed countries with large systems (50,000 nodes, many cascaded hydro systems). The latter demonstrates that the models and computing resources are available to perform this type of analysis. Of course, to help improve performance, as mentioned elsewhere, we have multiple licenses to allow for distribution of workload across multiple CPUs in a PC, and multiple PCs.

This section builds on the previous section on Models by discussing their applicability in the Vietnam PDP context.

**ABB E7 - Applicability to Vietnam Power Development Planning**

- ABB E7 Provides capabilities to model cascading hydro systems at both long and short timeframes
- Custom hydro generator efficiency, maximum capacity and minimum capacity as a function of storage level is not available
- PROMOD HD has the capability to model nodal transmission systems. Limitations from PROMOD IV in this regard should have been upgraded.
- Energy and reserves are fully co-optimized, also an upgrade from PROMOD IV
- PROMOD HD has the capability to model a range of power markets, including power pools

**PLEXOS - Applicability to Vietnam Power Development Planning**

- PLEXOS has a detailed and sophisticated hydro modeling methodology, including cascading hydro over long term and short-term timeframes, as well as stochastic hydro modeling
- PLEXOS models generator efficiency as a function of storage level
- PLEXOS fully models nodal transmission networks and computes nodal prices reflecting energy, loss, and congestion prices. N-1 or custom-defined contingencies are modeled.
- Energy and reserves are fully co-optimized
- PLEXOS has the capability to model a range of power markets, including power pools and nodal energy markets, and in addition has several pre-defined market structures that simulate generator bidding behavior, and which can also be customized.
- PLEXOS has significant gas pipeline (and fuel delivery) capabilities

**Balmorel - Applicability to Vietnam Power Development Planning**

- Balmorel models long term hydro capacity expansion; however, custom constraints in the GAMS modeling language would need to be added (and tested/validated) for detailed cascade hydro modeling
- Custom generator efficiency as a function of storage level is not available but could be added (and tested/validated). This essentially becomes a software/model development exercise, along with associated software debugging and testing. Given the time frame for the PDP study, time for software development is unrealistic.
- Operational reserves are not modeled, though custom constraints in GAMS could be added. There is an existing add-on unit commitment module that was developed by an academic institution, but technical support is likely not available. This module has likely undergone little use and testing, compared to other models.
- It appears that Balmorel models only zonal power systems, with zonal prices set by marginal units. Nodal transmission constraints cannot be represented.
- Balmorel has no capability to model a real-world power market.

**PDPAT - Applicability to Vietnam Power Development Planning**

- PDPAT does model hydro generation, but does not appear to have the ability to model cascaded hydro generation
- It is not known if hydro generation efficiency is modeled, and no documentation on the hydro modeling in English is available
- PDPAT models zonal rather than nodal systems
- Reserves are modeled, but they are not part of the optimization. Reserves are not co-optimized
- Given the structure of the Japanese market, it is likely that PDPAT primarily focuses on modeling fully integrated generation, transmission, and distribution systems
- There does not appear to be any capability to model power markets

**Markal/Times - Applicability to Vietnam Power Development Planning**

- MARKAL/TIMES models hydro systems at a relatively high level, with limited detail as cascade hydro or generator efficiency
- MARKAL/TIMES does not model nodal transmission networks.
- Detailed reserve co-optimization with energy is not modeled
- Power markets are not represented

As previously mentioned, the PDP results are critical in that they provide information that will be used to make decisions that have large impacts (financial, environmental, social, etc.) for the country, and the region. The software costs are insignificant in comparison with the consequences of the PDP. Since selection of the appropriate tools can have a large impact on the PDP results, it is essential that the proper tools be selected. Considerations for selection of the (long/short term) simulation tools include:

- Cost is factor but should be kept in the proper context. Solutions which may result in incorrect results may result in tremendous costs in the long term (e.g., incorrect selection of generation projects). Also, if a less expensive solution requires more effort on the part of the power system planner, the overall cost of the solution, including the planner's time, may be higher.
- Ability to accurately and natively model necessary elements of the system (power markets, cascaded hydro, hydro capabilities as a function of reservoir levels, co-optimization of energy and reserves, nodal capabilities with n-1 requirements)
- State of the art tools that are reasonably new and yet in wide use. Preferably, the tools should be using current algorithms, and not be based on algorithms that are decades old with patches to keep them current. At the same time, the tool should be in wide use, and have been used in several official and adversarial proceedings which implies they have been well challenged and tested.
- Prompt and quality support should be available. If questions arise, support staff should be available to promptly (i.e., a couple of hours) answer questions. If software fixes or enhancements needed, they should be available quickly, depending on the complexity, in a couple to several days.
- The model(s) should be relatively easy to use and manage. If multiple models are required, managing and coordinating multiple input databases adds to the complexity of, and potential for mistakes in, the process.

Ignoring license fees, PLEXOS and the ABB Suite are the two options that best meet all the criteria discussed above. Other tools fall short in one or more critical areas. Both PLEXOS and the ABB Suite can interact with PSS®E.[15] Further, there is a limited experience with PLEXOS and ABB Suite in Vietnam, and hence may not starting at the beginning of the learning curve.

It is very important that domestic expertise is developed in the modelling framework selected for the future PDPs (else the government of Vietnam would need to keep relying on expensive foreign consultancy support for PDP development), as well as that long-term sustainability of the modelling framework (e.g. in ensuring financing in the future) could be realistically ensured. There are examples (e.g. from Mexico) where the high annual licence fee for specifically PLEXOS has been a continuous challenge every year, risking its discontinuation.

### 4.2.9. PDP ZONING

The Danish Energy Agency (DEA), under the Danish Energy Partnership Program (DEPP), suggested that for PDP purpose the electricity system of Vietnam could be divided into 6 regions as follows:

[15] NREL has developed scripts to import a PSS/E case into PLEXOS. Those scripts are open-sourced and would be available to MOIT and the Modeling Working Group (MWG) working on PDP-8.

+ The North is divided into two regions: North and North Central

- **The North** consists of the provinces of the North-East, the North-West and the provinces of the Red River Delta. This is the central load area of the North.
- **The North Central** region includes Thanh Hoa, Nghe An, Ha Tinh and Quang Binh provinces. In these provinces many power generation sources are concentrated, and they are in the position of transferring the energy power.

+ Central and Southern regions are classified into four regions: Mid Central, Highlands, South Central and South Vietnam

- **The Mid Central** region includes Quang Tri, Thua Thien Hue, Da Nang, Quang Nam, Quang Ngai. These are concentrated with hydropower generation (Quang Nam), Coal power plant in Quang Tri and location of big CCGT using gas form Blue Whale field in Quang Nam, Quang Ngai provinces. This region is also located at the transfer location of the power supply.
- **The Highland** includes Kon Tum, Gia Lai, Dak Lak, Dak Nong, Lam Dong province. These are concentrated hydropower provinces and are expected to strongly develop solar power. For this area the power transmission direction and the capacity of transmission grid need to be determined.
- **The South-Central** region includes Binh Dinh, Phu Yen, Khanh Hoa, Ninh Thuan and Binh Thuan provinces. This is a region that is expected to strongly develop solar power and wind power. This area needs to determine the power transmission direction and the capacity of transmission grid.
- **The South** region includes the remaining provinces in the South East and South West. This is the central load area of the South. By 2025, the South East and the South West will be linked together by eight to ten 500kV single lines with total capacity over 15GW. Currently and looking ahead transmission system congestion is not anticipated and therefore there is no need to have more regions in the south.

### 4.2.10. Scenarios & Sensitivities

Several scenarios have been recommended in this report. Below is a sample of the areas for sensitivity analysis.

- Demand (e.g., high/low demand forecast; alternative demand response and/or electric vehicle deployment)
- Delays in project development (such as delays in acquiring financing)
- Hydropower availability (e.g., typical, wet year, dry year)
- Fuel prices (high/low coal, gas)
- Fuel availability/reliability
- Import/export options
- Solar and wind energy deployment (location, type, capacity)
- Transmission development strategies (e.g., RE Zones)
- Energy storage, other flexibility options
- Ancillary service procurement strategies (e.g., from RE)

– Constraints from contracts

### 4.2.11. Roadmap to Competitive Market

The national energy policy is for the electricity market to become more competitive over time. The exact timing of specific actions is not specified in legislation. To some extent, the market is open to new generating resources from privately owned generating plants and large consumers can produce their own power and sell the surplus.

Once market prices become competitive, power plant developers will have the option to enter and exit the market. The financing of the power plants will be without sovereign guarantees. To get to that point, the market structure (independent system operator, independent market operator, etc.) needs to be developed, rules adopted for their operation and software would be required to be purchased, tested and put into operation. Global experience shows this process may take 3-5 years once the government adopts a detailed electricity market concept design and an action plan to implement the market.

The future with mostly private investment in generation would change the approach to PDPs. The planning process would be broken into separate areas – network planning and security of supply. Ten-year network planning is performed every 2-3 years by the system operator to forecast the need to expand the network because of new generating projects, physical and economic congestion, increasing demand and the need to improve transfer capability with neighboring markets.

Security of supply studies are typically managed by the ministry responsible for energy issues. These studies analyze future energy sector trends to determine the possible reliability, safety and sustainability of the energy sector under different scenarios. The objective is to help ensure that customers are provided cost effective and reliable energy throughout the planning horizon. A common period for reviewing security of supply is once every 5 years.

The change in the process would see the transmission analysis done more frequently and many scenarios analyzed to determine the risks associated with supply development. The recommendations included in this report would help Vietnam move toward a process that would provide the analysis needed when the competitive market is open to price competition.

## 4.3. PDP ROLES

A key aspect of planning is the stakeholder process. Internationally, utilities frequently are required to publicly release and defend their IRPs in front of consumer advocates, Public Utility Commissions, and other stakeholders. Transparency and data openness are required, and the open process improves results. This suggests the capacity development is required for utilities, regulators, and public / consumer advocates. The processes should include mechanisms for periodic stakeholder review of the plan.

The MOIT has responsibility for and should manage and actively participate in the overall process. Based on international experience, it is important to have proper stakeholder involvement in the PDP process. This can be accomplished by the formation of two groups. Note that this same approach has worked well in other countries (e.g., the countries associated with the first several examples in the Appendix).

**A Modeling Working Group (MWG) should be formed**. The MWG would include representatives from the sector who will actively participate in the study. Members would be expected to collect data, shape modeling assumptions, help validate the model, simulate operations under a variety of modeling assumptions, review and provide feedback on intermediate results, provide feedback on study direction, participate in scenario development, and compile technical documents to disseminate findings. On average, the group may meet by webinar every week or two and in person every 2-3 months during development of the PDP. The MWG should include representation from the MOIT, EVN-NLDC, EREA, and the PDP-8 consultant. Subject to MOIT's direction, the MWG could also include donor-funded, international experts in state-of-the-art PDP-type analysis.

A crucial first step after establishing the MWG will be developing a work plan that clearly identifies the data collection and modeling leads for each component (e.g., demand forecasting, long-term modeling, operational modeling, PSS®E). To enable a fast start to the process, the MWG would leverage the existing capabilities and licenses within each organization. For example, the organization(s) that have a license and previous experience using PSS®E might lead this component of the PDP. Regardless of whether they also have a model license, other MWG members will be involved in reviewing the inputs and outputs of the model for validation and capacity building purposes. For new models (such as the operational model), the international expert could lead the analysis, working side by side with at least one other MWG agency to build the model to ensure staff new to such technical models learn and retain abilities to use and maintain such models and the corresponding input databases. The model databases would be shared (under a non-disclosure agreement as necessary) with all MWG members.

Among MWG members, EVN-NLDC shall be given an important role as ***co-lead of the production cost analysis***, as EVN-NLDC already uses production costs models to conduct short-term planning. In past PDP processes, EVN-NLDC has validated the PDP capacity expansion scenario outputs using its own version of Strategist. Providing EVN-NLDC with the data and methodology for also testing the operational feasibility of PDP scenarios using its production cost models will institutionalize a more robust validation process and enable EVN-NLDC to directly assess any operational concerns related to high variable RE scenarios.

**A Technical Advisory Group (TAG) should also be formed**. The purpose of the TAG is to guide the modeling process and ensure that the results are technically accurate. Because the TAG will reflect expertise from across the power system, the TAG will ensure that this effort reflects a broad set of stakeholder practices and concerns, thereby raising the credibility of the outputs. The TAG provides this peer review and input at all stages of the work, from selection of data inputs through implications of results. The TAG can also serve to disseminate the results and key messages. TAG membership may consist of Line Ministries, system operators, regulators, private sector, NGOs, other donors, PCs and local authorities. The TAG might meet every 4-6 months.

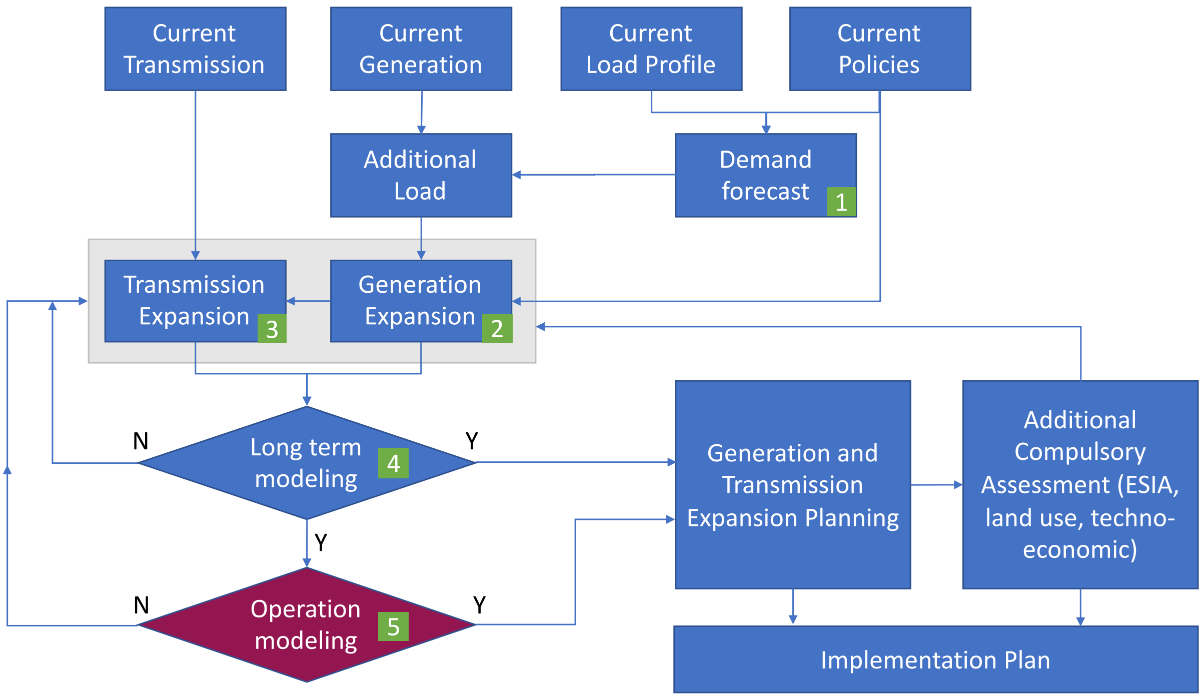
**Provinces.** To the extent that the WGs do not include provincial government representation as no longer provincial power development plans to be considered,[16] the PDP planners still have to cooperate with the representatives directly. The provincial government officials will have firsthand knowledge on local economic growth and permits for building new facilities, the interest in land acquisition by power plant developers, the growth in EVs and air conditioning, and many other aspects. As proposed PDP plans are developed, the provincial representatives can provide guidance as to the reasonableness of the plan related to their respective provinces. For example, if the plan states that there is plenty of land available for solar farms in a province, that statement should be reviewed by the provincial representatives to ensure the land is still available for that purpose.

[16] Following the new Law on Planning (No. 21/2017/QH14) in effect from January 1st, 2019.

## 4.4. SUMMARY

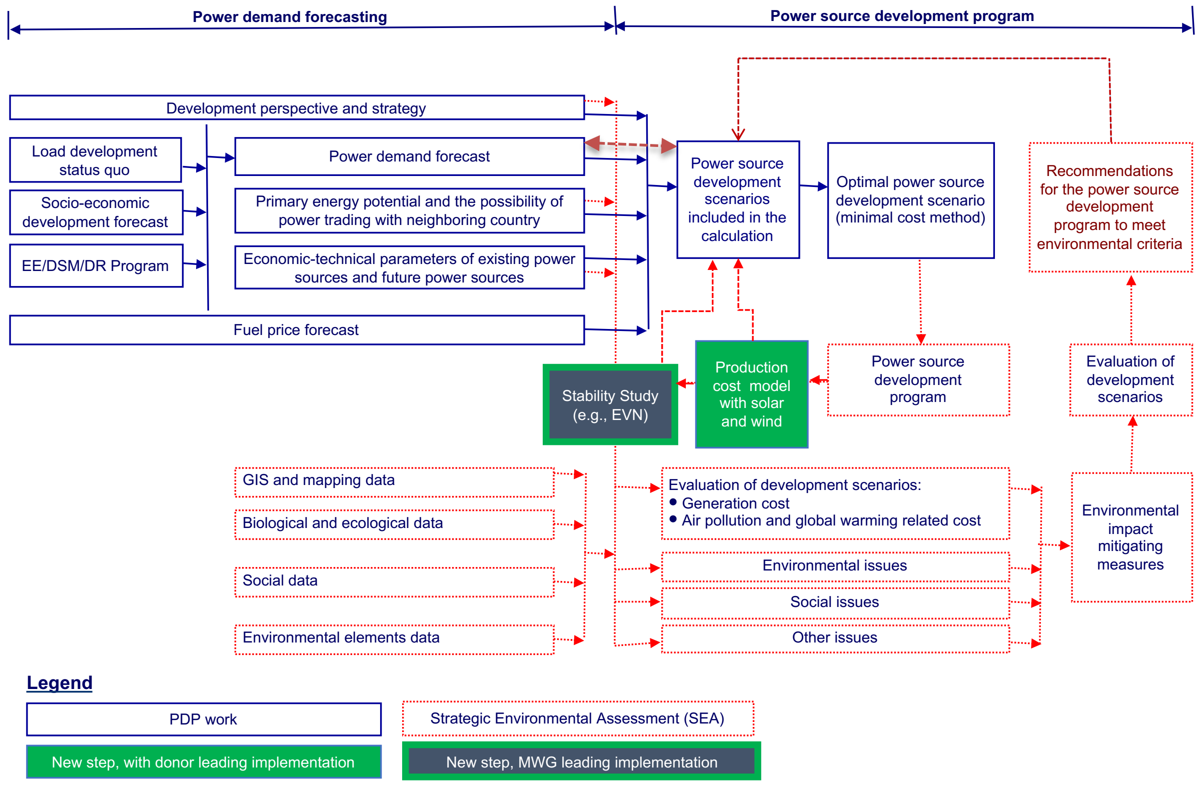
Drawing on the previous discussion, Figure 25 and Figure 26 show two additional schematics of the proposed PDP8 process. A key change relative to PDP-7/RPDP-7 is the addition of a new step to the traditional PDP process to test the operational feasibility of different variable RE target scenarios, including (but not limited to) the scenario(s) developed via the capacity expansion models. By implementing the approach shown in these figures—and by frequently updating it to reflect new understanding, trends, and priorities—PDP-8 will serve as a robust roadmap for power sector development in the coming decades.

*Figure 25: PDP Methodology Diagram*




*Source: Compiled by V-LEEP team*

*Figure 26: Proposed process for PDP-8, based on original PDP-7/RPDP-7 process*




Source: Compiled by V-LEEP/NREL team

It is essential that the modeling and scenarios for the PDP is undertaken by domestic experts. Expertise developed in PDP development should be used for future energy planning, adjustment of plans, analysis of measures etc. and dependanecy on foreign expertise will limit this. Modelling and scenario expertise takes long time to build (often years), and with the limited time for the PDP process existing experiences in specific modeling tools is key to ensure an effective combination of high quality analysis by foreign experts with core work done by Vietnamese experts.

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# APPENDIX

## APPENDIX A1: INTERNATIONAL EXAMPLES

In the following, specific, and real world, examples of PDP type of analysis are provided not only to motivate the reader in general, but to show specific analysis that could be performed in Vietnam, to answer questions that should be studied in PDP-8 for Vietnam. Though the discussions are focused on specific areas of interest, all of these come from complete studies and involved all aspects of the proposed methodology.

### POWER DEMAND FORECASTING

#### Evaluation of DR/DSM

Demand Response (DR) and Demand Side Management (DSM) are also examples of products which can have significant system benefits but must be analyzed with respect to system location and with respect to detailed hourly load profiles at multiple system buses. In Vietnam, consideration of DR/DSM will very likely be part of the PDP-8. The value of demand response must be evaluated in this context to guide government regulators and utilities in setting appropriate prices.

For a recent DR analysis, part of a national PDP study, historical customer data for candidate feeders for a pilot project were collected, and a forecast for the pilot was developed. Using PLEXOS, system operational modeling was used to estimate system benefits, while ensuring reserves, nodal constraints, hydro constraints, and other generator operational constraints were all satisfied. The tables below show the energy by resource (including demand side resources) for each scenario, which evaluate different transmission level bus locations for the DR programs.

Table A-1: Reference and Demand Response Case Scenarios

| Type of Generator | Reference Sept 5-14 (GWh) | DR A Sept 5-14 (GWh) | DR B Sept 5-14 (GWh) | DR C Sept 5-14 (GWh) |
|---|---|---|---|---|
| Hydro | 81.0 | 81.2 | 80.9 | 81.1 |
| Wind | 57.9 | 57.9 | 57.9 | 57.9 |
| Geothermal | 147.0 | 145.7 | 146.2 | 145.8 |
| Diesel | 9.3 | 8.3 | 8.8 | 8.6 |
| GT | 0.2 | 0.2 | 0.2 | 0.1 |
| CoGen | 8.6 | 8.6 | 8.5 | 8.5 |
| Coal | 12.0 | 12.8 | 12.3 | 12.4 |
| Imports (Total) | 95.8 | 95.8 | 95.8 | 95.8 |
| Solar | 13.4 | 13.4 | 13.4 | 13.4 |
| Imports | 21.7 | 21.7 | 21.7 | 21.7 |
| Demand Response | 0.0 | 0.94 | 0.91 | 1.03 |
| Unserved Energy | 0.0 | 0.0 | 0.0 | 0.0 |
| Excess Energy | 15.1 | 14.7 | 14.8 | 14.7 |
| Total Unit Start Cost ($000) | 539.7 | 538.7 | 545.3 | 536.4 |
| Total Generation Cost ($000) | 10281.5 | 10204.9 | 10253.4 | 10210.4 |

The results also demonstrate that there can be a quantifiable impact from location on the value of a given DR program, depending on local resources, local bus demand profile, and transmission capability. In other words, the value of DR is specific to the location and related aspects.

Table A-2: Comparison of Reference and DR Scenarios

| Case | Base Case Value ($1000) | Case Value ($1000) | Value Difference Case – Base ($1000) | GWh Basis | Value $/MWh |
|---|---|---|---|---|---|
| DR A | 10281.5 | 10204.9 | 76.5 | 0.94 | 81.8 |
| DR B | 10281.5 | 10253.4 | 28.0 | 0.91 | 30.9 |
| DR C | 10281.5 | 10210.4 | 71.0 | 1.03 | 69.3 |

## LONG TERM PLANNING: GENERATION EXPANSION

### Expansion Plan – Coal Example

This example is from a PDP study. This same type of issue is likely to occur in Vietnam. The example demonstrates that operational behavior can be difficult to predict without proper modeling and can have large system impacts. Long range capacity expansion models will not be able to capture detailed operations of generation units when it is assumed that the units are committed and dispatched in the most economically optimal manner.

An analysis was conducted comparing configurations of a coal generation unit, with one, two, or three generating units of 333 MW each. These alternative configurations were studied because the large capacity of baseload coal power in the system was causing overgeneration conditions, and the capacity factor for the total 3 coal units of 1000 MW was lower than that assumed in the long-term capacity (long term model) plan and the project PPA when modeled in a detailed hourly operation framework. The question was asked, what would change in the system if there was less coal capacity, by reducing or delaying the number of coal units.

Surprisingly to the System Operator and the national electricity regulator, the commitment and dispatch of the coal units were nearly identical with one, two, or three units. Upon reflection, this should not be surprising, since each individual unit is subject to the same unit commitment and dispatch economics and should be operated in the same manner to achieve optimal system cost.

Table A-3: Utilization Rates of Multi-Unit Coal Plants

| Type of Generator | Coal 3 Units Utilization Rate (%) | Coal 1 Unit Utilization Rate (%) | Coal 2 Units Utilization Rate (%) |
|---|---|---|---|
| Hydro | 44.9% | 46.4% | 45.6% |
| Wind Curtailment Rate | 0.0% | 0.0% | 0.0% |
| Geothermal | 77.2% | 83.3% | 79.5% |
| Diesel | 2.9% | 9.8% | 5.9% |
| GT | 0.9% | 1.7% | 1.4% |
| CoGen | 48.1% | 51.8% | 49.4% |

| Type of Generator | Coal 3 Units Utilization Rate (%) | Coal 1 Unit Utilization Rate (%) | Coal 2 Units Utilization Rate (%) |
|---|---|---|---|
| Coal | 25.6% | 27.3% | 28.3% |
| Net Imports | 74.9% | 74.9% | 74.9% |
| Solar Curtailment Rate | 0.0% | 0.0% | 0.0% |

The figures compare the dispatch of one and two or three coal units, respectively, on the same

High peak day example. As can be observed in Figure 2, there is an overgeneration condition until hour 6, with two coal units running, which does not occur in Figure 2 with only one unit. The coal units, which have minimum up-times of 168 hours, were committed to meet system load, which is the economic priority in the system. Some other units, such as wind, would need to be curtailed to balance system generation and load during these overgeneration hours, at an economic cost.

It is very important that such detailed and often complex interactions among generation units be modeled and understood, which can only be done in a modeling system such as PLEXOS, and not in long term capacity expansion models.

Figure A-1: Daily Dispatch of One Coal Unit on High Peak Day

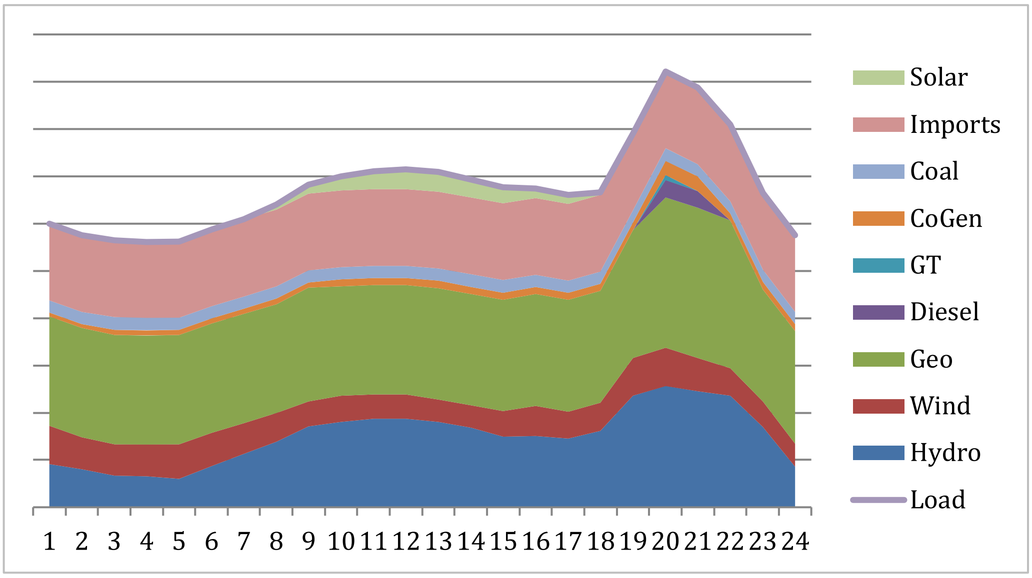
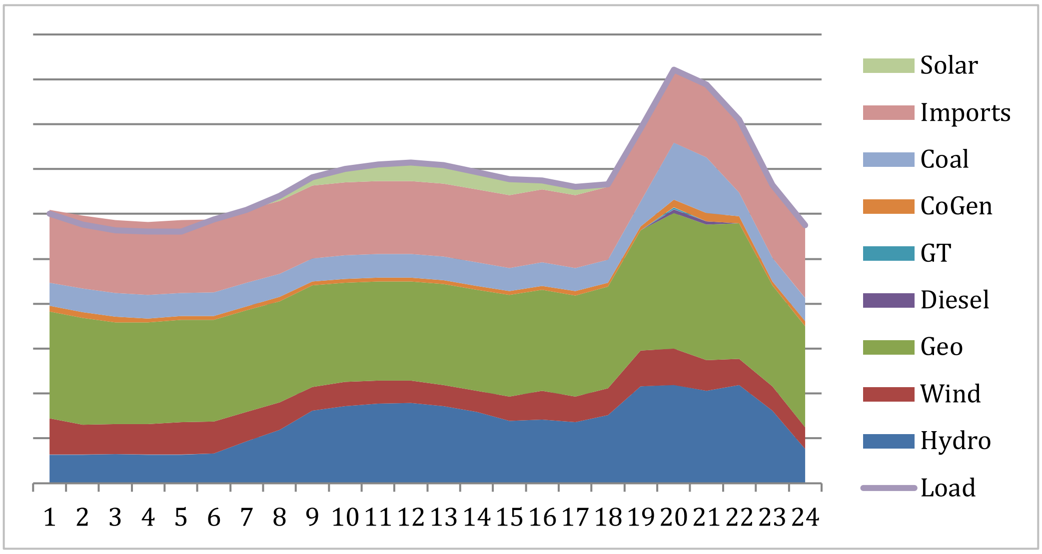


Figure A-2: Daily Dispatch of Two or Three Coal Unit on High Peak Day

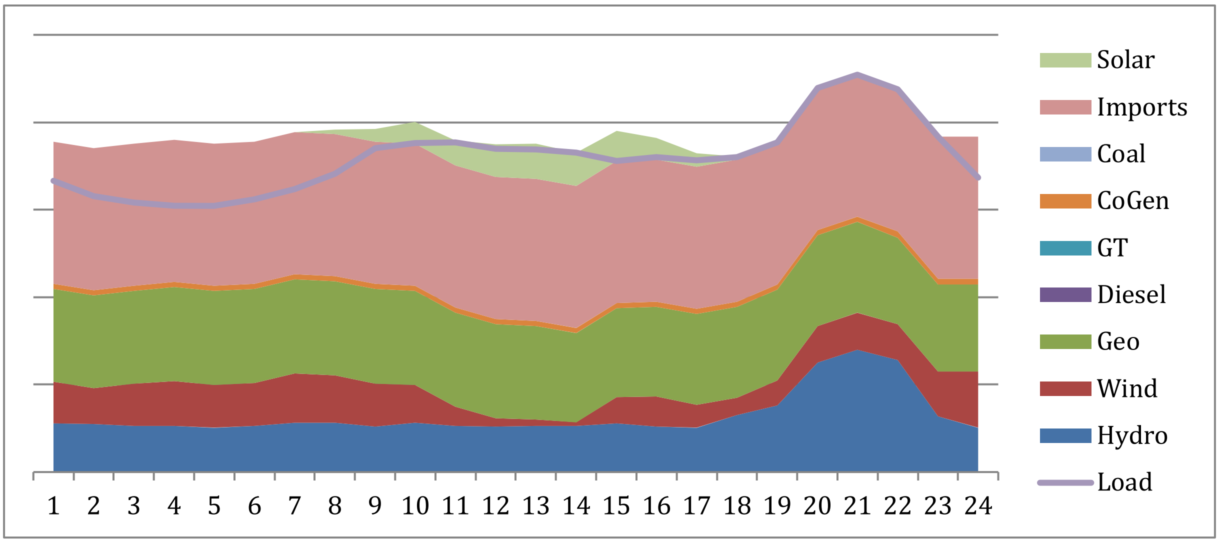



## Expansion plan – Generation Mix

This is another example from a PDP study, with significant generation having similar characteristics to Vietnam. The selection of generation mix can have significant impact on system operations and are typically not identified when only using long range (long term) planning models. Issues such as load factor, reliability requirements, lack of system flexible generation, and variable renewable energy patterns can cause over generation issues which can only be captured with operations models. It is important to model systems on an hourly basis for a full year of representative renewable generation profiles, and with more data if possible. It is not sufficient to selection only a "typical" week or weeks.

The figure shows the dispatch of a national system on a peak load day. Baseload coal generation is required to meet peak load, but due to long minimum up-time requirements (168 hours in this case), the system also experiences over-generation conditions in low load hours and in high solar generation hours.

Figure A-3: Dispatch of System Generation on Peak Demand Day, with Over-Generation Conditions



## Example Valuation of Solar Resources

This is another example from an actual PDP study. Similar to Vietnam, the country is considering significant additions of solar (and wind). As can be seen in this example, it is simplistic to think of having a single price for solar, as there can be large variations. The issues illustrated here will certainly have applicability in Vietnam. The locational value of generation resources can only be evaluated with detailed integrated models of generation and transmission simulated on an hourly basis. The value of a generation resource to the system, be it variable renewable energy, other generation, or other product such as demand response is dependent on site and power system dynamics. Important system characteristics to consider include:

- Availability of transmission
- Coincidence with load and other resources
- Cost of displaced resources
- Impacts on reserves
- Potential and magnitude of excess generation

The specifics, and associated operations cost/savings need to be understood to evaluate generation options and energy procurement and to support PPA negotiations.

For example, three different solar resources with different capacities and different locations were evaluated in a national system in PLEXOS. Depending on local load conditions, generation, and transmission capability, the value of each option can be very different. The following analysis compares two different locations and three different projects. The dollar comparisons are 1000s of US Dollars of total system costs in each scenario and are compared on a per MWh basis for each proposed project.

- Value Analysis, Location A, 40 MW solar
  - $702,127 Base, $708,448 w/o solar, Difference = $6,321
  - 83.9 GWh basis
  - $75.2/MWh Value
- Value Analysis, Location A, 120 MW solar
  - $702,127 Base, $707,566 w/o solar, Difference = $5,439
  - 251.9 GWh basis
  - $21.6/MWh Value
- Value Analysis, Location B, 95 MW solar
  - $702,127 Base, $705,107 w/o solar, Difference = $2,980
  - 180.8 GWh basis
  - $16.5/MWh Value

## Imports – Value of Flexibility

This is another example from a PDP study, with similarities to what will need to be evaluated in PDP-8. Vietnam may import and export power in the future. Regardless of the direction, the need and concepts discussed in this section apply. The following example comes from a national system that had negotiated a power import contract with a neighboring country. Without analyzing the value of flexibility to the system (of which the system is in need), the importing country decided to contract for firm power at a lower per unit cost, compared with flexible power at a higher per unit cost. Under the firm contract, imports of 400 MW were "must-take" in each hour, with an annual 75% capacity factor to account for import outages. It was assumed that under the flexible contract, hourly imports could range between zero and 400 MW, but annual total energy had to be the same (75% of 400 MW hourly) as in the firm contract.

Using PLEXOS to compare the Reference case (which reflects the firm negotiated power) to a flexible case, it was determined that the country could pay up to an additional $41/MWh for flexible power and still benefit.

Table A-4: Reference and Flexible Imports Comparison

| Type of Generator | Reference (GWh) | Flexible Imports (GWh) |
|---|---|---|
| Hydro | 3838.0 | 3965.1 |
| Wind | 2485.8 | 2485.8 |
| Geothermal | 11993.5 | 12502.3 |
| Diesel | 536.2 | 207.6 |
| GT | 260.3 | 111.6 |
| CoGen | 583.2 | 615.7 |
| Coal | 3595.6 | 3141.8 |
| Solar | 469.6 | 469.6 |
| Imports | 2624.8 | 2623.8 |
| Unserved Energy | 0.2 | 0.0 |
| Excess Energy | 998.7 | 734.7 |
| Total Unit Start Cost ($000) | 37990.1 | 23665.3 |
| Total Generation Cost ($000) | 826373.4 | 718041.1 |

The above shows the total system costs and the generation by unit type under the two scenarios. The value of the flexible imports is calculated as:

- $826,373 Base, $718,041 Flex (total system costs), Difference = - $108,332
- 2,624 GWh basis - energy taken under Flexible imports
- $41.3/MWh Value, cost savings per MWh of flexible imports

Much of the value of flexible imports derives from the ability to use imports to meet peak load, and to use cheaper domestic resources such as geothermal in lower demand hours, as seen in the figures below. Less import energy is taken in lower demand hours when geothermal energy is available, and more is taken in peak hours, offsetting diesel and GT generation.

Figure A-4: Reference Dispatch on Peak Day

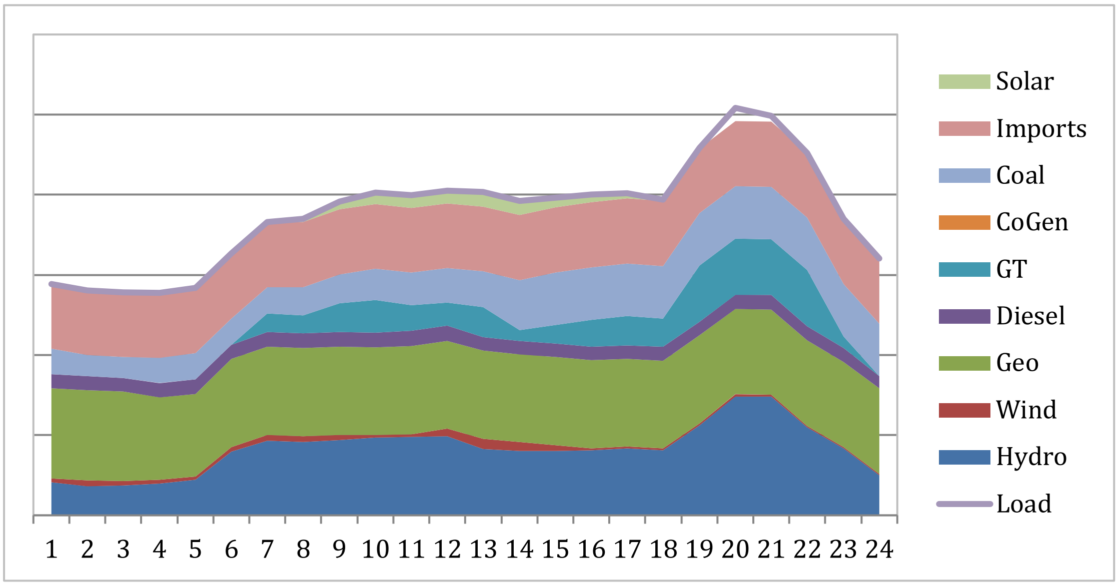
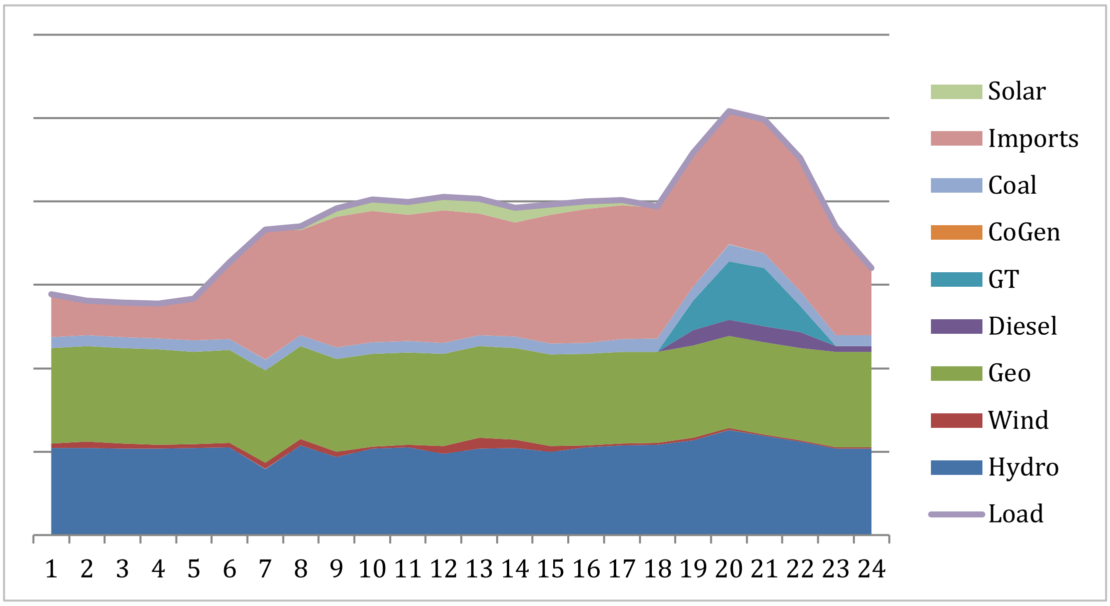



Figure A-5: Flexible Imports Dispatch on Peak Day




## Evaluation of Different Technologies (Geothermal minimum)

This is another example from a national PDP study. In this portion of the study, options regarding configurations of geothermal plants were being considered. Though Vietnam may not have much geothermal, as part of PDP-8, there will undoubtedly be options around different plant configurations to consider.

When system flexibility is required, there can be different options for achieving it – for example, adding more flexible units such as combined cycle natural gas, modifying existing or planned conventional units such as coal to operation as intermediate units to cycle more frequently, curtailing wind and solar, or modifying geothermal units to run at lower minimum load and to be able to ramp more quickly. These options must be evaluated in an operational model to compare their relative economics.

In PLEXOS, evaluation of the operational benefits and costs for using geothermal technology that would allow generation at lower minimum load was evaluated with respect to hourly annual operations within the full system. Minimum loads (% of full capacity) of 50%, 40%, 30%, and 20% were compared by simulating the optimal system dispatch under each scenario and comparing the change in system cost under the flexible case to the base case and calculating the cost savings on a MWh basis. It was determined that each increment of additional flexibility had greater value. Of course, capital investment is needed to achieve each level, and must be compared to the associated operational benefits. The system calculations for each scenario are shown below:

**50%**

- $456,717 Base, $456,029 Flex Geo, Difference = - $688
- 202 GWh basis - reduction in generation
- $3.40/MWh Value – cost savings per MWh of flexible geo

**40%**

- $ 456,717 Base, $454,638 Flex Geo, Difference = - $2,079
- 231 GWh basis - reduction in generation
- $9/MWh Value – cost savings per MWh of flexible geo

**30%**

- $ 456,717 Base, $453,800 Flex Geo, Difference = - $2,917
- 291 GWh basis - reduction in generation
- $10/MWh Value – cost savings per MWh of flexible geo

**20%**

- $ 456,717 Base, $452,847 Flex Geo, Difference = - $3,869
- 356 GWh basis - reduction in generation
- $10.9/MWh Value – cost savings per MWh of flexible geo

In each case, the savings could be paid to the generator to cover its cost and rest is a system benefit.

### Delay in retirement, new generation, project delay

Tradeoffs in the timing and delays of project completion, proposed retirements, and delayed retirements, all in relation to future system demand, obviously all have significant impacts on system operations, and will be an integral part of PDP-8. In one example from the case of a national energy plan, the timing of a 1000 MW coal project, and the impacts of a delay or cancelation of the project, were evaluated. In the case of the project delay/cancelation, an additional option of the delay of existing thermal units to serve peak demand was evaluated. The table displays the Reference case with 1000 MW coal, the delayed project case with no coal, and the delayed coal project case with additional delayed retirement diesel generation capacity. The retention of the diesel capacity is valuable in meeting unserved load that occurs under the No Coal scenario. Although there is a small amount of unserved energy remaining in this case, the total system costs are lower than that of the Reference case with 1000 MW. Economic supply options could be evaluated to determine the value of the unserved load, and the additional cost required to fully meet peak load requirements.

Table A-5: Reference, Delayed/No Coal, and Delayed/No Coal with Delayed Diesel Retirement Comparisons

| Type of Generator | Reference with 1000 MW Coal (GWh) | No Coal (GWh) | No Coal with additional Delayed Diesel Capacity (GWh) |
|---|---|---|---|
| Hydro | 3845.4 | 3993.0 | 3993.3 |
| Wind | 2485.8 | 2485.8 | 2485.8 |
| Geothermal | 7813.5 | 8843.2 | 8796.7 |
| Diesel | 101.6 | 432.7 | 528.7 |
| GT | 11.4 | 31.6 | 16.3 |
| CoGen | 461.0 | 526.9 | 514.3 |
| Coal | 2198.9 | 0.0 | 0.0 |
| Imports (Total) | 5331.6 | 5331.6 | 5331.6 |
| Solar | 469.6 | 469.6 | 469.6 |
| Imports (Net) | 2624.8 | 2624.8 | 2624.8 |
| Unserved Energy | 0.0 | 12.9 | 0.8 |
| Excess Energy | 852.5 | 261.1 | 270.8 |
| Total Unit Start Cost ($000) | 20528.8 | 23110.3 | 30148.1 |
| Total Generation Cost ($000) | 593891.7 | 544387.2 | 559328.9 |

## VRE Example & Considerations

Like Vietnam, in this national PDP study, there was consideration of adding varying (low to high) amounts of wind and solar generation. In power systems with increasing penetration levels of variable renewable energy, it is crucial to appropriately capture representative hourly generation from a full year, and ideally from several years, and from a meteorologically typical year. Seasonal and hourly wind and irradiance profiles at specific locations will have significant effects on available VRE generation and must be captured in detail – it is not sufficient to use annual average capacity or "typical week" profiles. The following charts show actual wind and solar profiles at various time scales for different locations in a national system. It is also important to consider the combined profiles of many VREs in a statistical manner (standard deviation of short-term variability), which ultimately impacts the variability of net load, which then determines generator commitment and dispatch.

Figure A-6: Seasonal Distribution of Generation of Sample Wind and Solar Sites

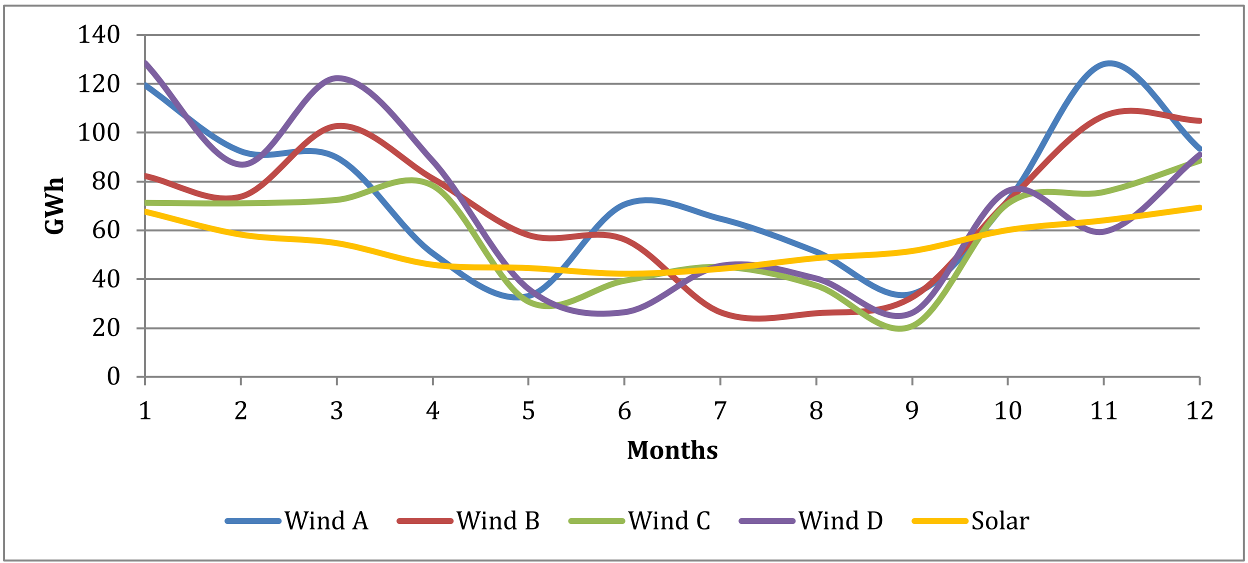



Figure A-7: Daily Generation at a Wind Site in January, April, June, and October

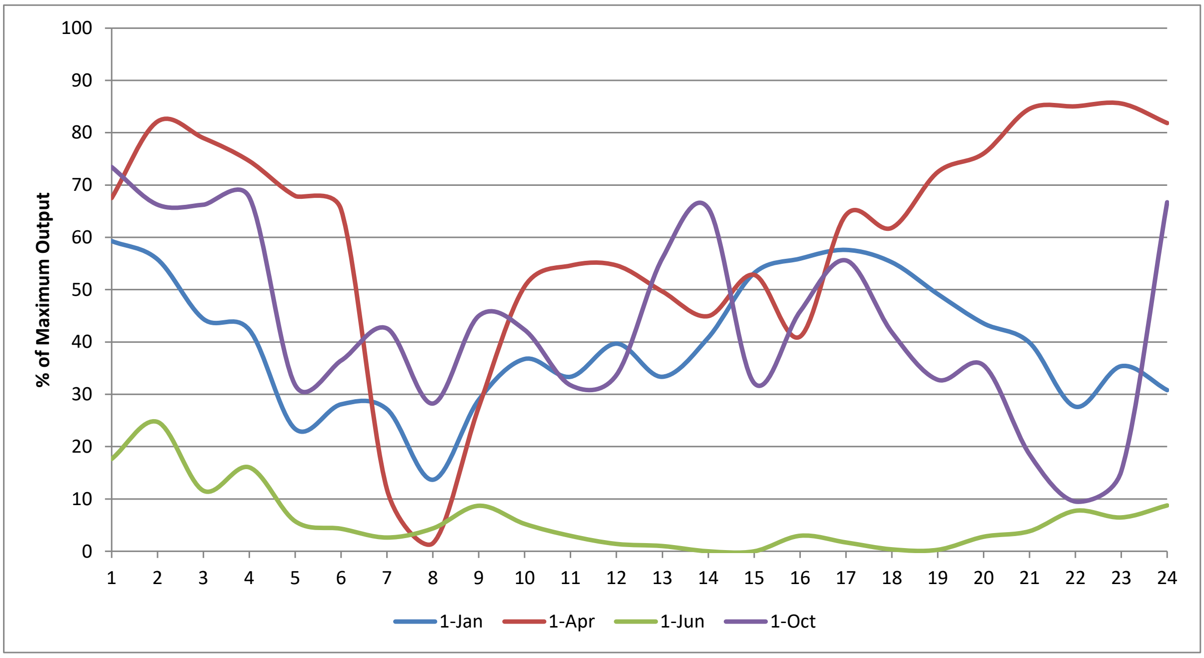
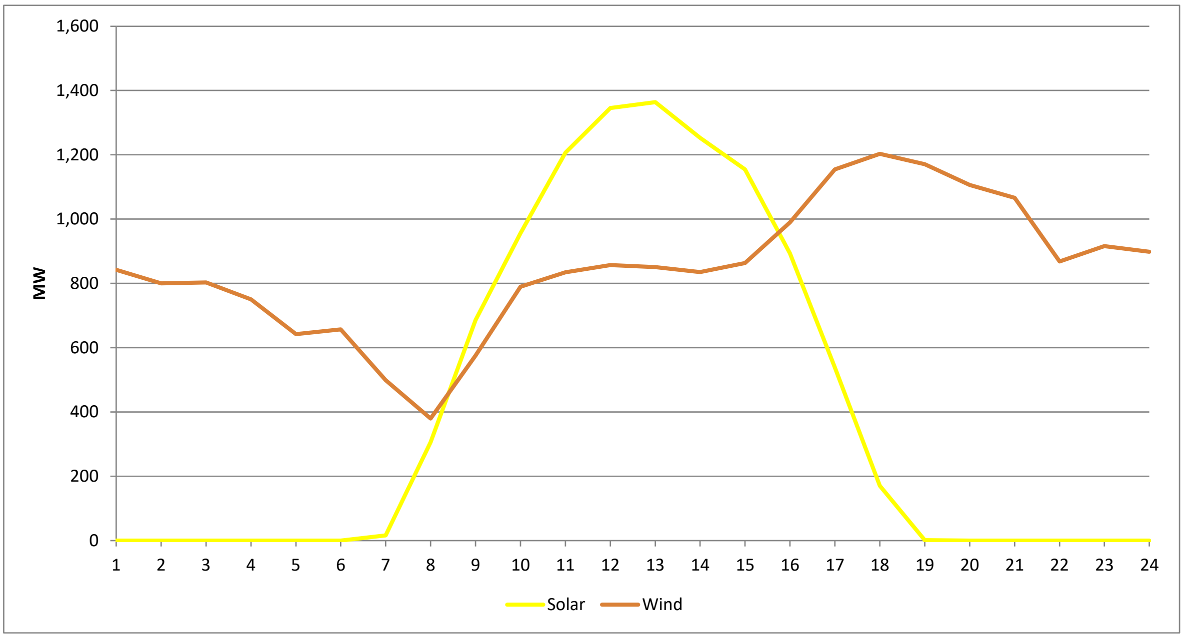
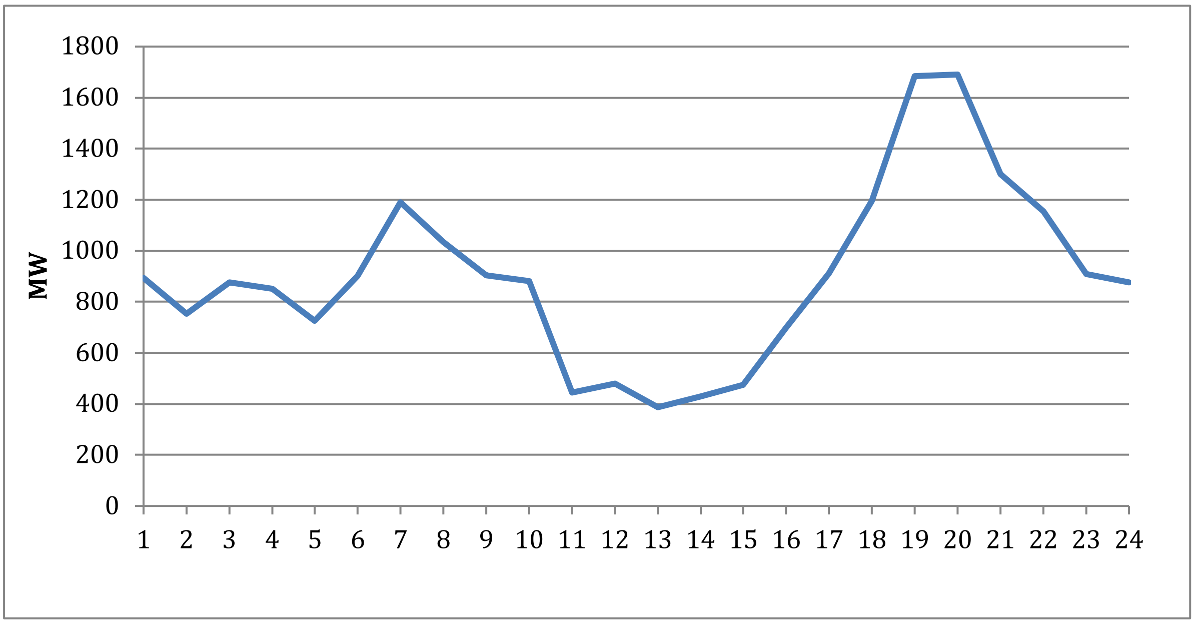


Figure A-8: Daily Generation at a Wind and Solar Site




The figure below demonstrates the impacts that the integration of VRE can have on existing traditional resources. In this case, the dispatch for a hydro unit in a cascaded network is significantly impacted by the large amount of solar energy produced in the system between hours 11 and 17. The hydro unit is then required to ramp between hours 17 and 21 to provide energy to meet peak load. The change in dispatch for this hydro unit will also impact the dispatch of other hydro units in the cascade. Assuming water is not being not spilled, which of course it not desirable, this has significant impacts on river operations (downstream water level, water flow, etc.). Though the power system can accommodate the VRE, there is a question as to whether the environmental impact of the VRE, in terms of the river operations, is acceptable.

Figure A-9: Modified Hydro Dispatch with VRE



## Southern California Transmission study

During the fact-finding mission, the need to study different transmission options was discussed. This example demonstrates an analogous and actual example from a California study. It also demonstrates the ability to setup a model and to validate it by performing a backcast (replicating a historical period). A detailed hourly nodal production simulation model was developed to assess the impacts on wind and solar curtailment and transmission line utilization of alternative configurations and project time delays of a major 500kV transmission project in Southern California, considering transmission outages on one or both circuits of the project, and modeling the system with and without an associated transmission segment, and a longer project completion time. The model was developed as part of a State of California regulatory and judicial proceeding on behalf of a municipality and contested by a large utility. As such, the model underwent significant adversarial scrutiny, and the results of the model were extensively validated against historical actual power system and market operations.

As shown in the table below, it was determined that renewable curtailment was not impacted by the design of the transmission line.

Table A-6: Renewable Curtailment for Alternative Transmission Configurations

| | Base | 8A out | UG 5 | UG 5 PO |
|---|---|---|---|---|
| January | 6.75% | 6.75% | 6.75% | 6.75% |
| February | 5.25% | 5.25% | 5.25% | 5.25% |
| March | 6.49% | 6.49% | 6.49% | 6.49% |
| April | 6.20% | 6.20% | 6.20% | 6.20% |
| May | 7.48% | 7.48% | 7.47% | 7.48% |
| June | 7.32% | 7.33% | 7.32% | 7.32% |
| July | 5.42% | 5.41% | 5.41% | 5.42% |
| August | 7.00% | 7.01% | 7.01% | 7.01% |
| September | 8.91% | 8.91% | 8.91% | 8.91% |
| October | 7.86% | 7.86% | 7.87% | 7.86% |
| November | 7.79% | 7.79% | 7.79% | 7.79% |
| December | 5.33% | 5.33% | 5.34% | 5.34% |

The analysis was also able to predict the utilization of the transmission line under the alternative configurations presented in the next table. While the utilization of the line was impacted by the design under the alternative configurations, with utilization a typical utilization increasing from 15%

to 50%, the capacity of the line was well within the specified thermal limits throughout the year and demonstrated no appreciable impacts on system transmission congestion.

Table A-7: Transmission Line Utilization for Alternative Transmission Configurations

| | Base | UG 5 | UG 5 PO |
|---|---|---|---|
| January | 12.49% | 20.59% | 40.32% |
| February | 12.98% | 22.09% | 43.60% |
| March | 10.94% | 18.03% | 35.44% |
| April | 11.72% | 19.18% | 38.13% |
| May | 17.69% | 29.00% | 57.18% |
| June | 20.72% | 31.62% | 61.97% |
| July | 18.10% | 29.77% | 58.71% |
| August | 15.74% | 25.90% | 51.12% |
| September | 14.23% | 23.39% | 46.19% |
| October | 8.48% | 14.06% | 27.51% |
| November | 8.09% | 13.29% | 26.16% |
| December | 11.74% | 19.24% | 37.64% |

## Transmission Congestion Impacts & Curtailment Risk for a New Wind Plant in the Western USA

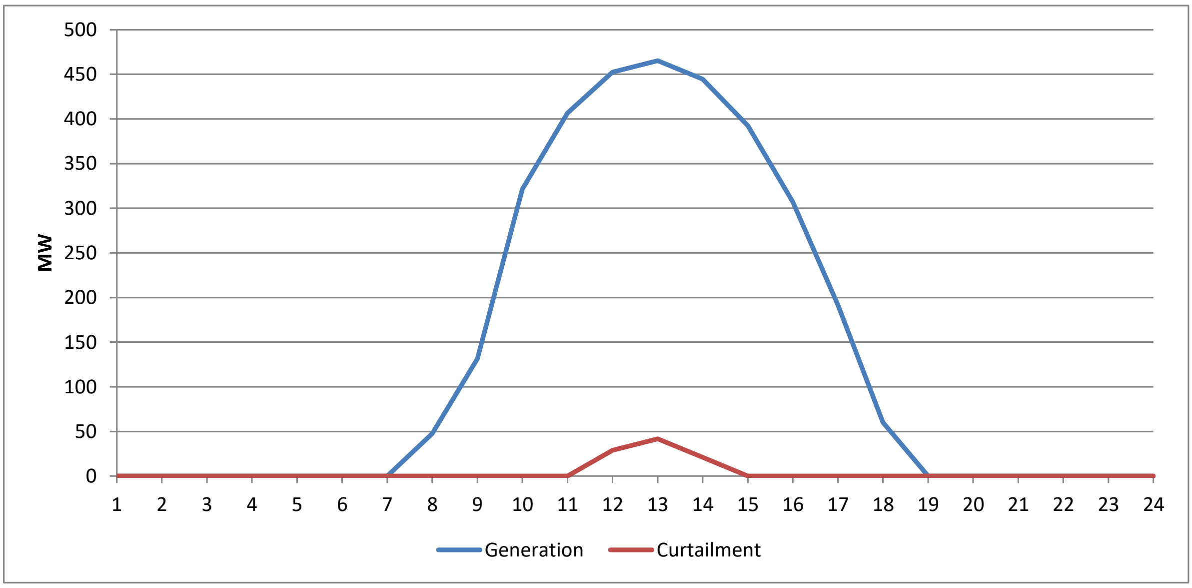
As Vietnam considers adding VRE resources, curtailment risk for such resources needs to be assessed, in addition to transmission congestion. The latter were two of the objectives in this study. Hourly production simulation models that replicate and predict the operation of power systems and markets, and which replicate the dispatch and commitment decisions made by a System Operator, are commonly used to justify the financing of privately developed generation projects. The models are used to validate the operation of the units in the energy and reserve markets relative to negotiated Power Purchase Agreements, and to provide assurances that the facilities will not be negatively impacted by local transmission congestion that could result in generation curtailment. This type of analysis provides assurances for the “bankability” of a project.

One example was for a for a new 315MW wind farm, for which financial institutions that were to provide project debt were concerned about the potential impact of congestion on the dispatch and revenue of a plant, particularly given the significant new planned capacity of wind generation in the region. The full power system, the specific plant, and several other proposed wind plants in the region were modeled. Scenarios related to transmission outages, varying levels of wind, and different bidding strategies were modeled. The project lenders were ultimately satisfied and proceeded with funding the project, and the wind project is now operational.

## Solar Curtailment due to Congestion

As Vietnam is considering adding significant amounts of solar generation, PDP analysis needs to concern itself with related aspects such as congestion. This is an example from a portion of a national PDP study, evaluating solar. VRE curtailment may be required under conditions of system over-generation or due to transmission congestion. The figure shows an example in which local transmission is unable to evacuate solar energy and peak production, resulting in generator curtailment.

Figure A-10: Solar Curtailment Due to Congestion




## Evaluation of two coal configurations

Comparing alternative generator configurations relative to power system requirements is often required and can only be considered using detailed operational models. This is another example from a national PDP study.

For example, in a system with an excess of baseload power and a shortage of flexible power, a baseload and an intermediate duty coal unit were compared. In this system, even though the variable unit costs of operating the intermediate duty unit are high (due to unit cycling and more frequent starts and stops and the associated start and stop costs), the system generation cost is reduced with the intermediate unit. The costs savings on an annual basis can be compared with the potentially higher capital cost investment required to appropriately design the Intermediate unit.

Table A-8: Evaluation of Two Coal Configurations

| Type of Generator | Baseload Coal (GWh) | Intermediate Coal (GWh) |
|---|---|---|
| Hydro | 3845.4 | 3964.6 |
| Wind | 2485.8 | 2485.8 |
| Geothermal | 7813.5 | 8380.3 |
| Diesel | 101.6 | 93.4 |
| GT | 11.4 | 9.7 |
| CoGen | 461.0 | 478.1 |
| Coal | 2198.9 | 1183.3 |
| Solar | 469.6 | 469.6 |
| Net Imports | 2624.8 | 2624.8 |
| Unserved Energy | 0.0 | 0.0 |
| Excess Energy | 852.5 | 530.0 |
| Total Unit Start Cost ($000) | 20528.8 | 42712.8 |
| Total Generation Cost ($000) | 593891.7 | 575570.8 |

The first two figures for a Baseload Coal unit and the second two figures for an Intermediate Coal unit are compared for the same two days of commitment and dispatch. On day 1 of each case, the system experiences an outage of imports. In both cases, the coal unit can provide the required system energy in place of imports. The Baseload unit, once committed, is required to remain in operation, resulting is significant system overgeneration in low load hours on day two. The Intermediate unit, since it is more flexible, can shut down, avoiding the overgeneration. The intermediate unit is then re-committed and dispatch in the peak hours on Day 2 to meet the system peak load.

Figure A-11: Dispatch of Baseload Coal Unit (Day 1)

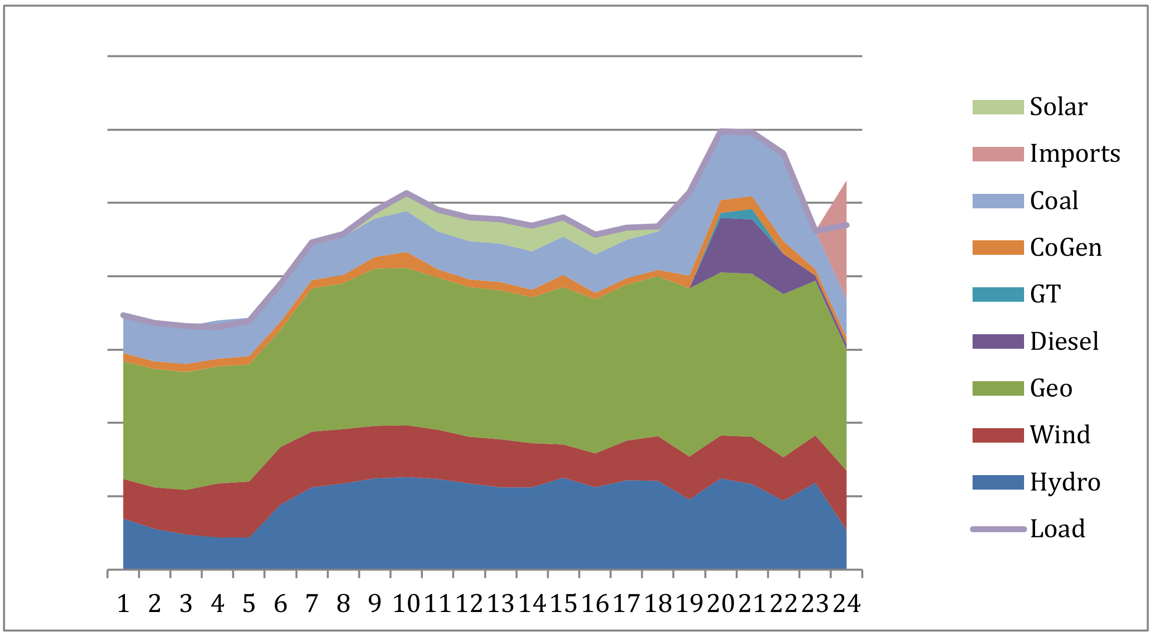



Figure A-12: Dispatch of Baseload Coal Unit (Day 2)

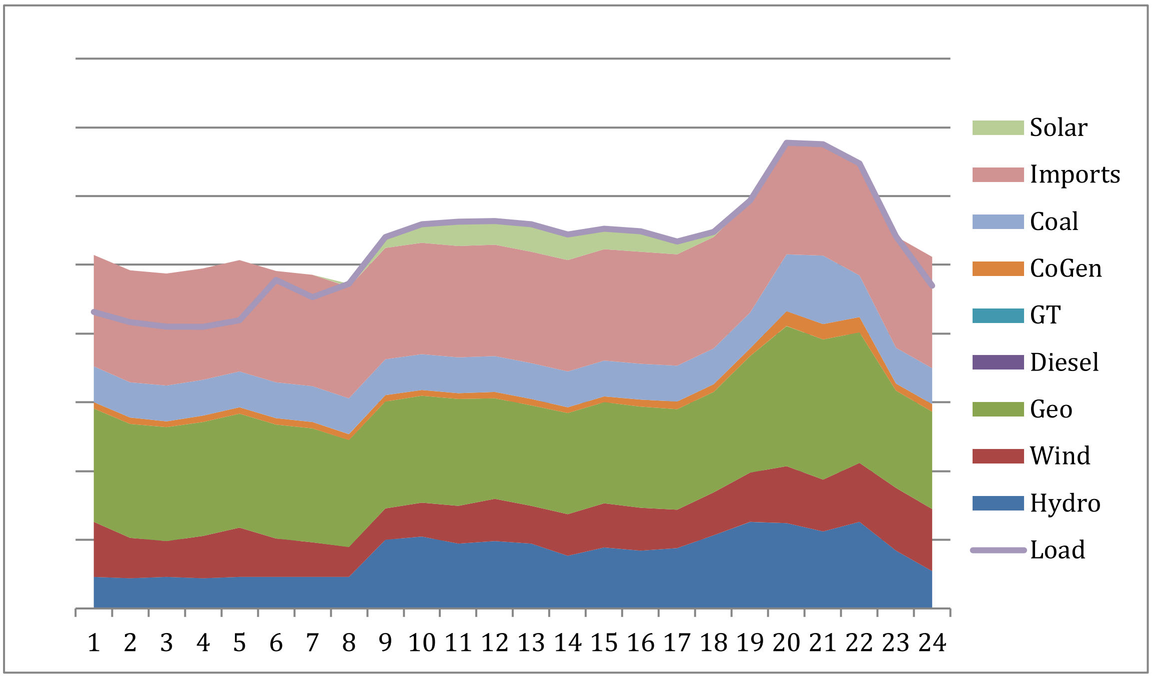


Figure A-13: Dispatch of Intermediate Coal Unit (Day 1)

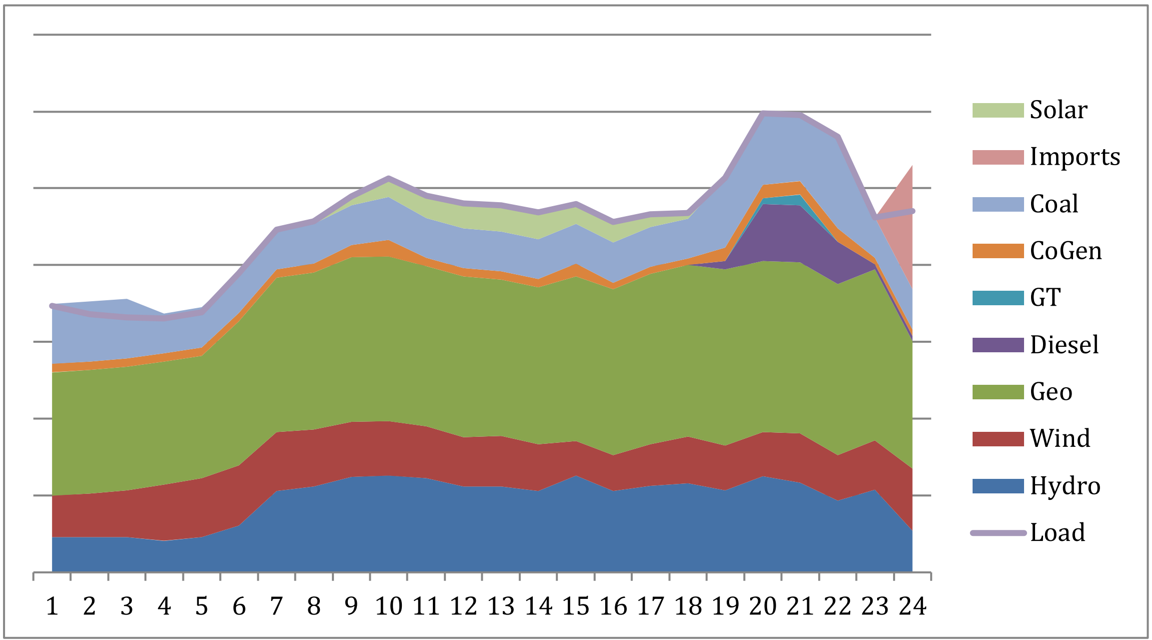
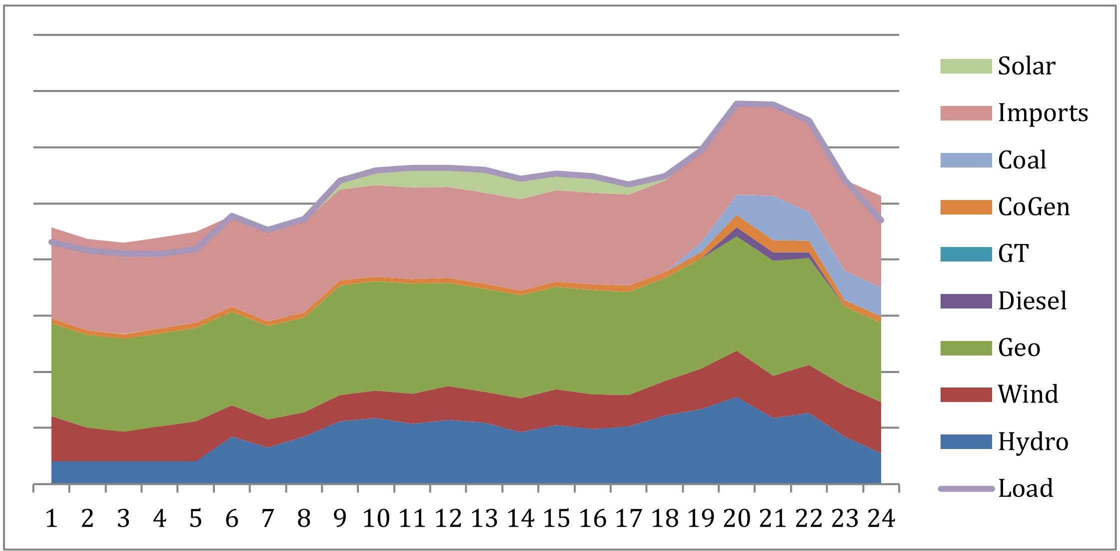



Figure A-14: Dispatch of Intermediate Coal Unit (Day 2)




## Operating Reserves Example

The following example drawn from the long range (PDP) plan for a national electricity system, in which the timing of and capacity of large coal plant was being evaluated. To accurately model the operations of the system with and without the coal unit, operating reserves must be part of the modeling and optimization. The co-optimization of reserves, as well as capturing the characteristics of operating reserves in the modelling, due to its impacts on generator and system operations will be important in PDP-8.

In the case with the 1000 MW coal plant, the primary reserve requirement (Spin) is large due to the requirement to carry system reserves sufficient to replace the largest on-line unit in any hour, which is this case is one of the three coal units at 333 MW. The Spin and Regulation reserves are primarily provided by hydro units. There is a small shortage of Spin in this case, which places the system at risk in the 268 hours of reserve shortage during the year.

When the coal plant is delayed, the total Spin requirement is reduced, because the largest units in the system, either geothermal or hydro units, are 100 MW. However, the Spin shortage persists, because the hydro units are required to provide more energy (serving load is prioritized over providing reserves), and thus less capacity is available to provide both Spin and Regulation. The Regulating reserve shortage increases in the No Coal scenario.

This analysis demonstrates the impact of a delay of a coal plant on operating reserves, which can only be assessed when energy and reserves are modeled in a co-optimization framework on an hourly basis over the course of a full year.

Table A-9: Comparison of Operating Reserves for Reference and No Coal Scenarios

| Scenario/Reserve Type | Provision (GWh) | Shortage (GWh) | Shortage Hours |
|---|---|---|---|
| Reference | | | |
| Non-Spin | 2,803.0 | 0.2 | 3 |
| Regulation Down | 872.7 | 1.6 | 49 |
| Regulation Up | 873.5 | 0.8 | 22 |
| Spin | 1,417.5 | 14.4 | 268 |
| No Coal | | | |
| Non-Spin | 2,754 | 48.3 | 372 |
| Regulation Down | 874 | 0 | 0 |
| Regulation Up | 865 | 9.3 | 131 |
| Spin | 626 | 13.6 | 239 |

## Variability Analysis for Reserve Requirements

This example is also from a national PDP study. In the following example, the requirements for operating reserves, for future years under various scenarios, are calculated based on reliability requirements. These requirements are then used as inputs to the operations model. The required amount of Regulation (or secondary) reserves is based on the variability of demand and VRE resources, or net load. Secondary reserves are assumed to be under the control of the System Operator via Automatic Generation Control (AGC) and can respond to changes in net load within minutes. Contingency (or primary) reserves are provided by generators via governor control within seconds and are replaced by the provision of secondary reserves via AGC.

Historical sub-hourly data for load and VREs is required to calculate regulation reserve requirements, although there is existing industry experience and practice in small to large systems that provide guidance on requirements.

The increase in variability of the net load compared with total load – as measured by the standard deviation of 10-minute changes – is used to calculate the incremental regulation requirements above load only requirements. For systems with modest intermittent generation penetration levels, between 10-15%, the additional requirements tend to be modest, on the order of 2-5% of the added renewable capacity. Requirements for larger systems also tend to be modest because of the geographic diversity of the intermittent generation, and the fact that the combined variability of load and generation tend to offset the variability of the intermittent resources.

The table below shows an example of the calculation of regulation reserve requirements drawn from actual data from a national system. The total wind and solar capacity for Year 1 is 745 MW, for Year 2 is 810 MW, and for Year 3 is 985 MW. Total load only regulation reserve requirements grow in absolute terms as load grows, but at a slower rate. The incremental regulating reserve requirements for the VRE is modest; in Year 1, less than 20 additional MW of regulating reserve are required for the 745 MW (or 2.6%); in Year 2, the incremental requirement is 2.3% of VRE capacity, and in Year 3 the incremental requirement is 2.2%. This declining requirement is due to the greater geographic diversity of the VRE and the relative "smoothing" of the net load, as load and VRE variability is combined.

Table A-10: Comparison of Operating Reserves for Reference and No Coal Scenarios

| Year | Peak Load (MW) | Regulation Requirement (% of Peak Load) | Total Load Only Regulation Requirement (MW) | Standard Deviation of 10 Minute Wind and Solar (MW) | Total Regulation Requirement (MW) |
|---|---|---|---|---|---|
| Year 1 | 2845 | 2.2 | 62.6 | 17.8 | 82.3 |
| Year 2 | 4431 | 1.65 | 73.1 | 18.5 | 91.8 |
| Year 3 | 6833 | 1.25 | 85.4 | 21.7 | 107.4 |

However, the Spin shortage persists, because the hydro units are required to provide more energy (serving load is prioritized over providing reserves), and thus less capacity is available to provide both Spin and Regulation. The Regulating reserve shortage increases in the No Coal scenario.

### OPERATIONAL PLANNING: PRODUCTION COST MODELING

#### Market Revenue for a New Combined Cycle Western USA

Vietnam has a relatively new power market, which is expected to evolve in the coming years. The ability to accurately model the power market is essential, as it can have significant impacts on results. This example demonstrates analysis in such an environment. It also further demonstrates the ability to perform detailed backcast/validation exercises against history. It also demonstrates the need to perform operational level analysis in the context of studying thermal generation and transmission improvements. Existing power generation facilities often need to evaluate current and future power system operations and market conditions to be able to profitably operate, to evaluate bidding strategies, and to analyze the impacts of transmission system congestion on the price received from the market. This requires extensive calibration and validation of production simulation models relative to historical data and for developing future price forecasts under various scenario assumptions.

In one case, a new natural gas combined cycle plant owner needed to investigate more than six months of revenue received from the power market, during which time the plant was experiencing adverse market conditions. PLEXOS was setup and benchmarked to historical data for the year in question, and the model validated and quantified the owners concern about revenue, which amounted to a loss of $1.3M USD over the 6-month period due to transmission congestion that was impacting prices received for the generation and the commitment and dispatch of the generation plant.

The model was able to identify that market dynamics (in particular bidding behavior and market rules) were negatively impacting the plant, and the model quantified the benefit of a set of 230kV transmission upgrades to the plant's revenue stream. The plant owner is currently funding the upgrades. The model analysis was also used to obtain project approval from the California Independent System Operator as part of the annual transmission system planning process.

## Unit Commitment issue – Why are GTs running more than expected?

This example, part of a PDP study, is an example of the operations model identifying issues that are missed in the long-term model. Similar issues would likely arise in Vietnam. Long term capacity expansion models (Balmorel, TIMES /MARKEL, WASP, etc.) will typically only be able to provide annual, indicative capacity factors for different generation technologies given variable operating costs. The optimal economic use of a given project will be both a function of variable costs, such as variable fuel costs and operations and maintenance costs ($/MWh), and the fixed costs of starting and stopping a unit ($/start and $/stop). To realistically model unit commitment and dispatch, and to determine the optimal operation of a given generation plant in a given system, both types of costs must be considered.

One example of this is the operation of medium speed diesel plants and gas-fired turbine units. Both types of plants are typically used to serve peak load. MSD typically have lower variable costs, but higher start costs, slower ramping capability, and longer minimum load times that GT units.

If the plants were modeled only with variable costs, the MSDs would run more often, and GTs would only run when MSD capacity is exhausted. However, there are economic conditions under which GTs would be preferred to MSDs, which only become apparent in models that incorporate both variable and fixed costs of operation in a detailed hourly simulation.

For example, diesel units typically have start costs per unit of $2,250 with 50% minimum load, with 10-18 MW of capacity per individual unit and a total variable operating cost of $110/MWh.

GT units typically are faster and cheaper to start, with a $1,000 start cost, with typically a 20MW minimum load for 70 MW units, and, a $246/MWh variable operating cost.

If 25 MW is required at peak for only one hour, the following costs are incurred:

- Diesel: 2 units needed; 2*(2,250)+25*(110) = $7,200
- GT: 25*246 = $6,150+$1,000 = $7,150

In this example, the GT unit is the better choice than diesel for this hour as all constraints are met and it is more economical.

## Planning to Support Ambitious Renewable Energy Targets in India

The Government of India has established a target of 175 gigawatts (GW) of installed RE capacity by 2022, including 60 GW of wind and 100 GW of solar, up from 29 GW wind and 9 GW solar in 2017. Using advanced weather and power system modeling, a multi-institutional modeling team evaluated the operational impacts of meeting these targets and identified several actions that are favorable for integration. The modeling team consisted of representatives from the national grid operator, regulator, central transmission utility, and state load dispatchers, along with the National Renewable Energy Laboratory (NREL) and the Lawrence Berkeley National Laboratory.[17]

The study team's primary tool was a detailed production cost model (developed in PLEXOS-ST), which simulates optimal scheduling and dispatch of available power generation in a future year (2022) by minimizing total production costs subject to physical, operational, and market constraints. The model includes high-resolution wind and solar data (forecasts and actuals), unique properties for each generator, the anticipated buildout of the power system, and enforced state-to-state transmission flows. The study team used this model to identify how the Indian power system is balanced every 15 minutes, the same time frame used by power system operators. The model quantifies RE generation, including variability and curtailment, changes in least-cost scheduling and dispatch, flexibility of thermal generation, and periods of stress. To investigate system operations in each of the states with the potential for significant growth in RE capacity, the study team also used a higher-resolution regional model that includes intrastate transmission details.

Key planning-related results include the following:[18]

- Power system balancing with 100 GW solar and 60 GW wind is achievable at 15-minute operational timescales with minimal RE curtailment. India's current coal-dominated power system has the inherent flexibility to accommodate the variability associated with the targeted RE capacities, and coal flexibility in low-RE, coal-dominant states can play an important role in facilitating RE integration nationwide.
- The 160 GW of solar and wind capacity can serve 22% of India's power demand, providing benefits of fuel savings and reduced emissions.
- The power system as planned for 2022 can manage the added variability of wind and solar; new, fast-ramping infrastructure (such as natural gas turbines) is not necessary to maintain balance.
- In a system with 160 GW of wind and solar, coal plants, on average, operate at only half their capacity (see **Error! Reference source not found.**), suggesting the potential role for a new tariff structure that moves away from focusing on energy delivery and instead compensates plants for performance that achieves flexibility goals.
- The peak systemwide 1-hour up-ramp increases by 27% to 32 GW compared to 25 GW in a system with no new renewables. This ramp rate can be met if all generating stations exploit their inherent ramping capability.
- Batteries insignificantly impact emissions and total cost of generation.
- National and regional coordination of scheduling and dispatch eases renewable energy integration and results in cost savings by smoothing variability and broadening the supply of system flexibility.
- Reducing minimum generation levels of large thermal plants is the biggest driver to reducing RE curtailment.

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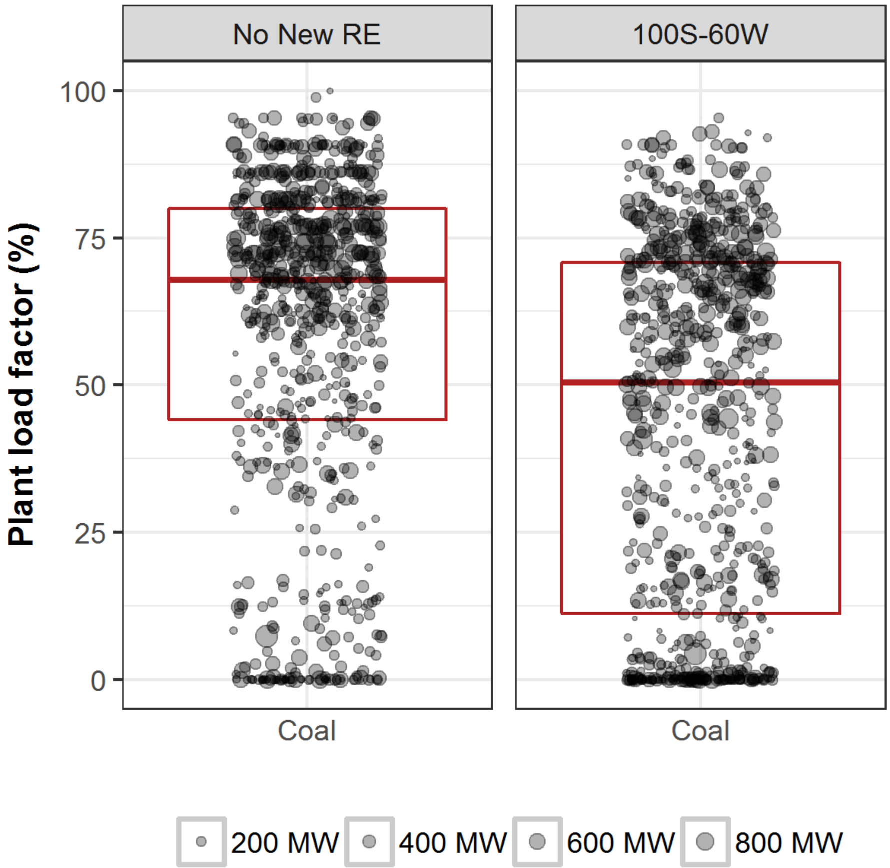
[17] For more information, including a visualization of the study's results, please see https://www.nrel.gov/analysis/india-renewable-integration-study.html.

[18] David Palchak, Jaquelin Cochran, Ali Ehlen, Brendan McBennett, Michael Milligan, Ilya Chernyakhovskiy, Ranjit Deshmukh, Nikit Abhyankar, Sushil Kumar Soonee, S. R. Narasimhan, Mohit Joshi, Priya Sreedharan. 2017. *Greening the Grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. I -- National Study*. NREL/TP-6A20-68530. https://www.nrel.gov/docs/fy17osti/68530.pdf.

Figure A-15: Simulated coal plant load factors for two scenarios for 2022: no new RE, and the current RE target (100 GW solar, 60 GW wind). Average coal plant load factors fall 63% in the "No New RE" scenario to 50% in the "100S-60W" scenario. Dots represent individual plants sized to nameplate capacity. Boxes represent divisions into 25th percent quantiles, meaning those above the box represent 25% of the capacity, those inside the box are the middle 50%, and those below are 25% of the capacity. The middle line is the median. Source: Palchak et al. (2017)




Building on this effort, the Government of India is now collaborating with NREL to improve the representation of variable renewable energy in its capacity expansion models.

## Exploring the Impacts of Different RE Targets and Siting Strategies in other Asian countries

- **Philippines**:

Under the leadership on the Philippine Department of Energy (PDOE) and USAID, a modeling team (consisting of representatives from NREL and PDOE, along with the Philippine electricity regulator, power system operator, and market operator) conducted a study to analyze the operational impacts of a variety of renewable energy scenarios in the Luzon-Visayas power system, which comprises the largest integrated grid in the Philippines.[19] The study uses a production cost model (developed in PLEXOS-ST) and detailed weather and power system data

[19] For more information, please see https://www.nrel.gov/news/program/2018/study-shows-philippine-power-system-can-achieve-30-and-50-renewable-energy-by-2030.html.

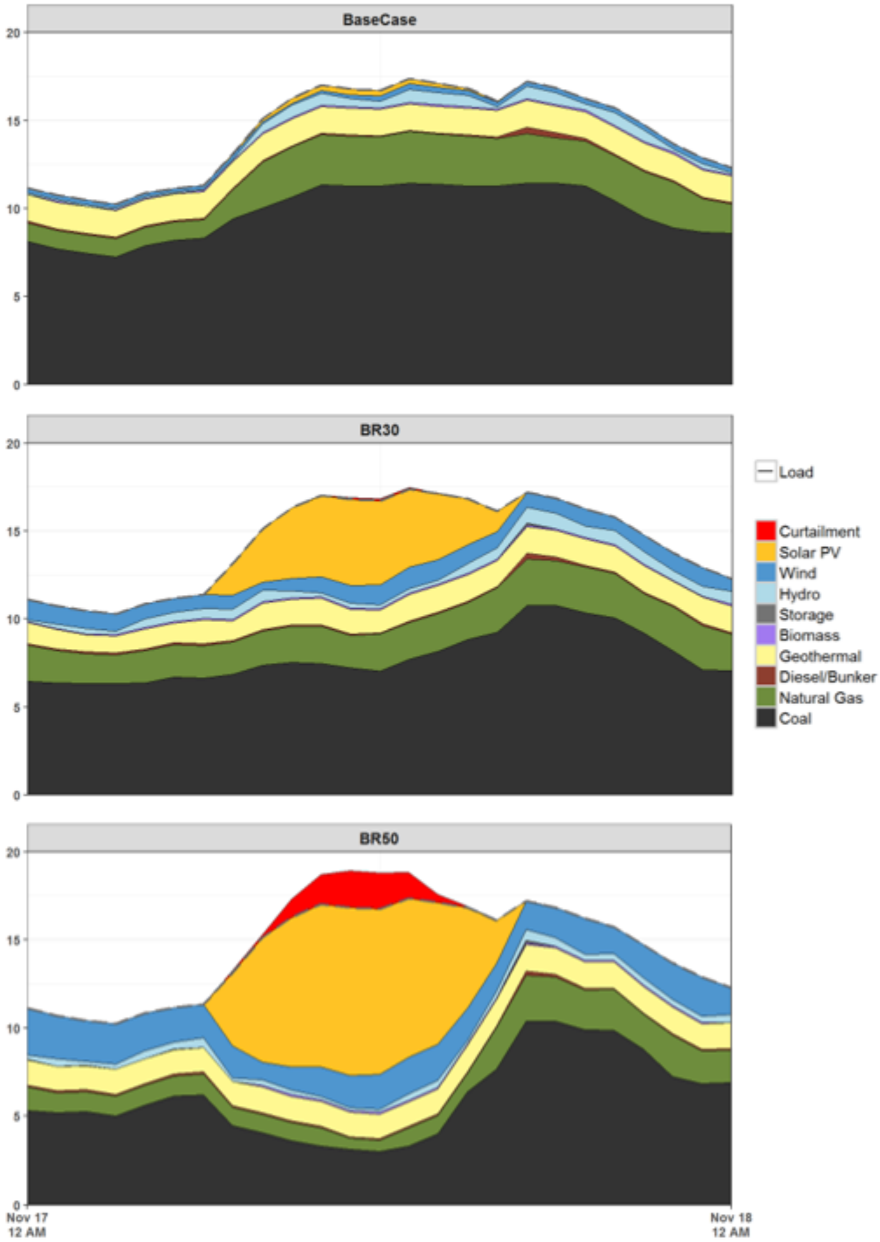
to examine the implications of achieving 30% and 50% renewable energy targets—primarily through the development of variable solar and wind energy—in the system planned for 2030. For each target level, the study also evaluates different siting strategies for solar and wind energy generators (e.g., generators in locations with the best solar and wind resources versus generators located near transmission capacity). For each combination of RE target and siting strategy, the production cost model simulates the hourly scheduling of least-cost electricity generation for one year under representative weather, load, and outage conditions, while adhering to the physical constraints of the generation fleet and transmission network.

The study highlights five key findings:[20]

1. RE targets of 30% and 50% are achievable in the power system as planned for 2030. Achieving these high RE targets will likely involve changes to how the power system is operated.
2. System flexibility will contribute to cost-effective integration of variable RE.
3. Achieving high levels of solar and wind integration will require coordinated planning of generation and transmission development.
4. Strategic, economic curtailments of solar and wind energy can enhance system flexibility.
5. Reserve provision may become an issue regardless of RE penetration. Additional qualified reserve-providing facilities, including from solar and wind generators, and/or enhanced sharing of ancillary services between the Luzon and Visayas interconnections will likely be needed.

[20] Clayton Barrows, Jessica Katz, Jaquelin Cochran, Galen Maclaurin, Mark Christian Marollano, Mary Grace Gabis, Noriel Christopher Reyes, Kenneth Jack Munoz, Clarita De Jesus, Nielson Asedillo, Jake Binayug, Hanzel Cubangbang, Rommel Reyes, Jonathan de la Vina, Edward Olmedo, Jennifer Leisch. 2018. *Greening the Grid: Solar and Wind Grid Integration Study for the Luzon-Visayas System of the Philippines*. NREL/TP-6A20-68594. https://www.nrel.gov/docs/fy18osti/68594.pdf.

Figure A-16: Hourly generation schedule on November 17 (Visayas evening peak day) in three scenarios: Base Case, 30% RE target met with a “best resource” siting strategy (BR30), and 50% RE target met with a best resource siting strategy (BR50). As variable RE penetration increases, coal and natural gas plants must be operated more flexibly to balance the system. Source: Barrows et al. 2018.

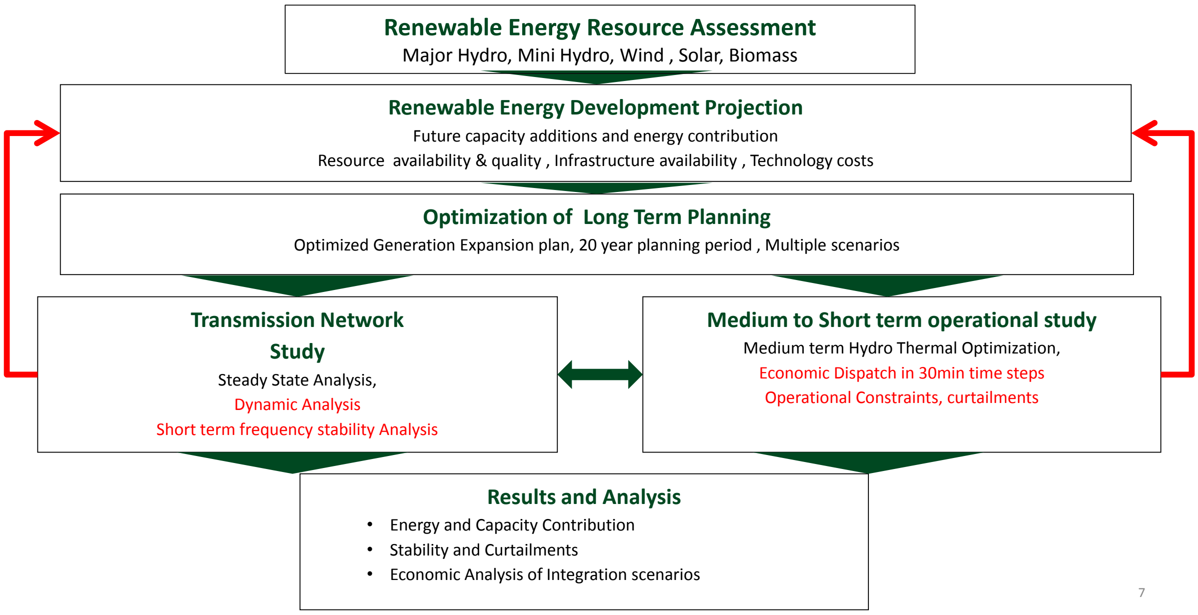



This study complements other power system planning analyses, such as capacity expansion and load flow modeling, that Philippine power system planners routinely undertake. Taken together, these studies contribute to the analytical basis for planning for a low-cost, clean, reliable, and flexible Philippine power system.

- **Sri Lanka:**

The Ceylon Electricity Board (CEB), Sri Lanka’s largest vertically-integrated utility, is conducting a suite of studies to determine the extent to which solar and wind energy can be integrated reliably and economically into the country's island power system.[21] Figure A-17: illustrates the different types of assessments CEB is conducting to analyze variable RE impacts. These assessments include capacity expansion (long-term planning), operational, and transmission network studies. Each type of study focuses at different timescales (ranging from seconds to decades) and yields different insights about the cost, feasibility, and reliability implications of higher variable RE penetrations. CEB's work in each area is ongoing. Recent efforts have included collaboration with NREL to examine the operational impacts (including RE curtailment) of cross-border trade with India via a high voltage direct current tie.

Figure A-17: Ceylon Electricity Board methodology for planning for higher levels of renewable energy




- **Thailand:**

At the request of Thailand's Ministry of Energy, the International Energy Agency (IEA) recently led a study to analyze the impact of variable renewable energy on Thailand's power system. The analysis was based on a production cost model (in PLEXOS-ST) that simulated operations at a 30-minute resolution. Scenarios included RE targets from Thailand's 2015 Power Development Plan (amounting to a 6% annual penetration of solar and wind energy) as well as higher variable RE scenarios (12% and 15% annual penetrations). The study also evaluated flexibility strategies such as battery deployment, conventional power plant cycling, and demand response from electric vehicles. The final analysis is forthcoming; preliminary results indicate that the more ambitious variable RE targets are feasible from an operational perspective and that demand-side measures, electric vehicles, and reduced minimum generation levels of conventional generators are cost-effective flexibility options.[22] Building on these results, the Hawaii Natural Energy Institute (HNEI)

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[21] H.M. Wijekoon and Randika Wijekoon. 2018. "Integration of Renewable Based Generation Into Sri Lankan Grid." Presentation at the Asia Clean Energy Forum, 5 June 2018, Manila, Philippines. https://d2oc0ihd6a5bt.cloudfront.net/wp-content/uploads/sites/837/2018/06/H.M-Wijekoon-and-Randika-Wijekoon-Integration-of-Renewable-based-Generation-Into-Sri-Lankan-Grid-2018-2028.pdf.

[22] Peerapat Vithayasrichareon. 2018. "Renewable Grid Integration Assessment: Overview of Thailand Case Study." Presentation at the Asia Clean Energy Forum, 5 June 2018, Manila, Philippines. https://d2oc0ihd6a5bt.cloudfront.net/wp-content/uploads/sites/837/2018/06/Peerapat-Vithayasrichareon-RE-Grid-Integration-Assessment.pdf.

is currently working with Thailand's power system stakeholders to conduct further operational modeling.

## Examples of Renewable Energy Scenario Analysis in Hawai'i

Given the rapid growth of wind and solar penetration, grid operators in Hawa'i are required to address integration challenges sooner than other US grids. In fact, O'ahu and Maui system operations have already been dramatically altered in the past few years to support renewable energy. Unlike other US grids that have large geographic footprints and transmission interconnections to neighboring grids, the integration challenges for Hawa'i are compounded by the fact that the power grids are small isolated islands. As a result, Hawa'i is becoming a test bed for renewable energy integration. The lessons learned here will be transferred to other North American grids as they begin reaching similar levels of renewable penetration.

Below are summaries of three renewable integration studies that were done in Hawa'i. A solar integration study for the island of O'ahu, a wind integration study for the island of Maui, and an assessment of the 40% Renewable Portfolio Standard (RPS) set for Hawa'i in 2030. The RPS also includes a requirement of 70% by 2040 and 100% by 2045.

### Hawaii Solar Integration Study

The Hawaii Solar Integration Study[23] analyzed five scenarios with different Solar PV (central and distributed) and Wind resources (on-island and off-island) for the island of O'ahu. One of the main objectives of the study was to identify the "pinch point" of the, 1,200MW peak, O'ahu grid. A "pinch point" can be defined as a scenario wherein it is anticipated (1) the system will not be able to absorb significant portion of available renewable energy with current operating practices, and/or (2). the sub-hourly response of the system is not sufficient to counteract the variability of renewable energy and regulate system frequency with current operating practices. Other study objectives are listed below, and the renewable scenarios considered are listed in **Error! Reference source not found.**:

- Assess the Solar PV and Wind energy delivered to the system
- Assess changes in variable operating costs, fuel consumption and fossil plant emissions
- Assess the dynamic performance of the O'ahu system in sub-hourly time frames from few seconds to an hour,
- Identify the challenges and impact to system operation, and
- Identify strategies that facilitate high penetrations of Solar PV and Wind power

[23] Hawaii Natural Energy Institute, GE Energy Consulting, "Hawaii Solar Integration Study: Final Technical Report for Oahu", https://www.hnei.hawaii.edu/sites/www.hnei.hawaii.edu/files/Hawaii%20Solar%20Integration%20Study%20-%20Oahu.pdf, April 2012.

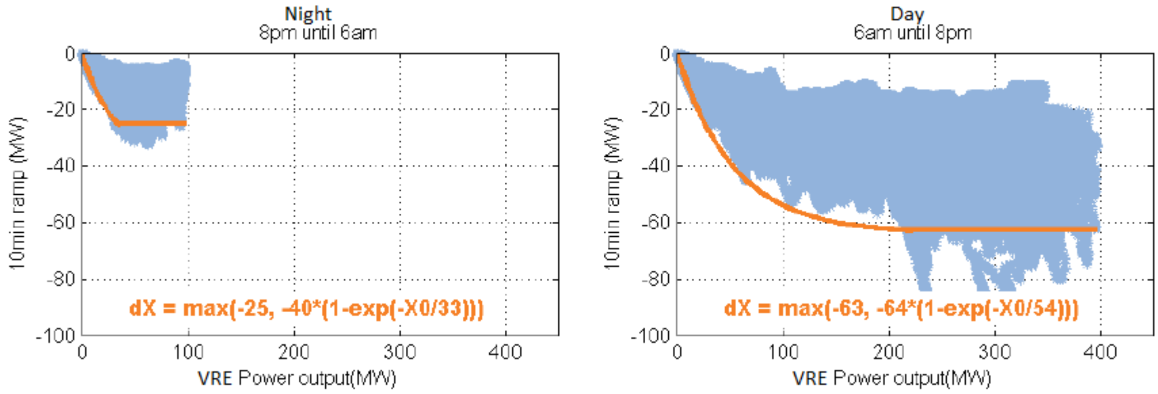
Table A-11: Hawaii Solar Integration Study Scenarios

| Scenario | Distributed PV | Central PV | On-island Wind | Off-island Wind | Total | Penetration by Energy |
|---|---|---|---|---|---|---|
| Baseline | 60MW | - | 100MW | - | 160MW | 4.9% |
| 3A | 260MW | 100MW | 100MW | - | 460MW | 11.1% |
| 3B | 160MW | 200MW | 100MW | - | 460MW | 11.5% |
| 4A | 360MW | 400MW | 100MW | - | 860MW | 20.2% |
| 4B | 160MW | 200MW | 100MW | 200MW | 660MW | 20.4% |

The study approach for each of these scenarios is summarized as follows:

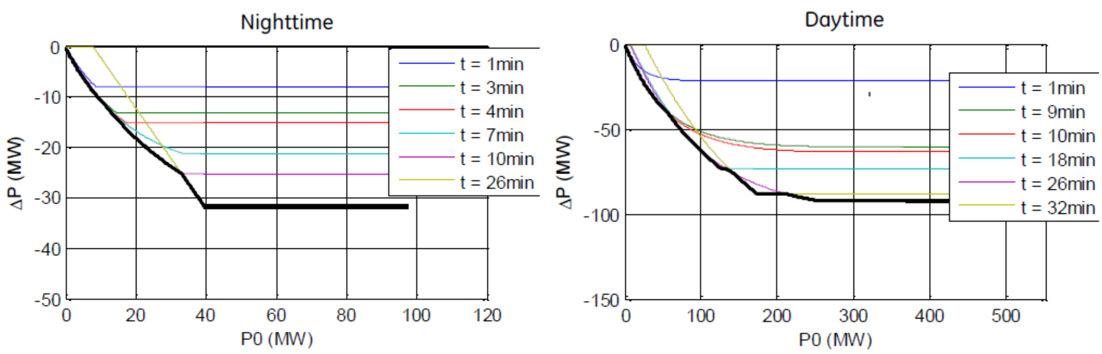
1. Quantify variability of aggregated wind and solar power resources using statistical methods. Determine changes in wind+solar power output in different time periods (5, 10, 30, 60 minutes). Figure A-18: shows a scatter plot in blue of all the 10-minute changes in power output from the wind and solar resources over the entire study year. The orange line shows the reserves required to cover 99.99% of the 10-minute changes in power.

Figure A-18: Renewable Resource Variability Analysis




2. Calculate required contingency and operating reserves for each scenario. Contingency reserves are spinning reserves that cover the loss of the largest generating resource (e.g., 185 MW to cover the AES plant on O‘ahu). Operating reserves are a combination of spinning and non-spinning resources that cover the variability in wind and solar resources. Total reserves are the sum of contingency and operating reserves.

Figure A-19: System Up Reserves Requirements




3. Simulate hourly system operations for a full year using production simulation analysis. Inputs include generating unit operating parameters (fuel cost, heat rate, start- up cost, variable O&M, etc.), reserve requirements, generation must-run schedules, hourly wind

and solar power output profiles. Quantify generating resource commitment/dispatch, variable operating costs (primarily fuel), emissions, and curtailment of wind/solar resources due to operational constraints.

4. Screen annual hourly operations data from the production simulation to quantify performance during sub-hourly intervals. This analysis examined wind and solar variability in several intervals (e.g., 5-min, 10-min, …) for each hour of the year, and measured the ability of the committed generation in each hour to follow that variability, within the constraints of unit ramp rates and min/max power limits, and without compromising contingency reserves.
5. Identify challenging time periods for grid operations per the following criteria:
6. For worst-case conditions identified in the screening process above, perform long-term dynamic simulations (1-2 hours) or transient stability simulations (30-60 seconds) using system dynamic simulation models to quantify the overall system response and to determine if the system could survive with adequate reliability margins.
7. For all study scenarios, tabulate operational constraints and performance issues that occur when using existing operational practices (e.g., down-reserve requirements, all reserves from thermal resources) and performance capabilities (e.g., Pmin of generating units).
8. Explore and test possible mitigation methods that would improve overall system performance with high penetrations of wind and solar resources (e.g., reducing Pmin of thermal units, reserves from demand response or energy storage resources, down-reserves from wind or solar resources). Performance improvements were quantified by a combination of production simulations and dynamic simulations.

Conclusions for the O‘ahu Electric Grid[24]

The O‘ahu electric grid can accommodate 360 MW of solar PV generation and 100 MW of wind generation with additional spinning reserves, investments in generating units to reduce their minimums, and improved ramp rates. This mix of wind and solar generation supplies 11% of O‘ahu’s annual electric load. If the solar PV resources are concentrated into larger plants with single-axis tracking rather than geographically dispersed with no tracking, the system will require more operating reserves to respond to the additional short-term variability in power output.

The O‘ahu electric grid with system modifications and additional reserves can accommodate additional wind and solar resources that result in renewable energy providing roughly 20% of the island’s annual electricity needs. Additional operating reserves are required under the 20% renewable energy scenarios. Daytime operating reserves are higher for the PV-dominated scenario, and nighttime operating reserves are required for scenarios with wind. Centralized PV plants have more variability and, hence, need more operating reserves than distributed PV.

These high-penetration scenarios resulted in some curtailment of wind and solar power. Under current operating practices, the wind and solar mix resulted in curtailment of 4.3% of the renewable energy, while the solar-dominant mix resulted in curtailment of 8.6%. Reducing the minimum power level of the thermal power plants is the most effective method of reducing curtailment. Other effective methods include:

- Allocating down reserves to wind and solar plants
- Relaxing fixed operating schedules for a few thermal units

[24] K. Eber, D. Corbus, Hawaii Solar Integration Study: Executive Summary, National Renewable Energy Laboratory, https://www.nrel.gov/docs/fy13osti/57215.pdf, June 2013.

- Providing reserves from alternate resources such as a BESS or demand response.

Combining these mitigation measures can reduce curtailment to less than 1%, which is very acceptable.

The study also found that, under the scenarios with high renewable energy penetration, the modified grid controls can maintain adequate frequency control for subhourly variations of wind and solar power. However, certain operating conditions and grid stresses could degrade the safety margins of the grid and make it less reliable. For example, when thermal generation is backed down to minimum dispatch limits, increased wind and solar generation will consume down reserves intended for loss-of-load contingencies. This can be resolved with an automated scheme to curtail wind and solar plant output and maintain required down reserves on the thermal units.

Likewise, system over-frequency responses for loss-of-load events can be improved if wind and solar plants are equipped with over-frequency governor controls. This reduces the risk of thermal unit trips because of transient excursions below minimum power levels. In addition, system under-frequency responses to generator trip events can be improved by a combination of synthetic inertia on wind plants and frequency-sensitive demand response.

**Maui Wind Integration Study**

The island of Maui has the highest level of wind and solar power capacity as a percentage of system load of all the Hawaiian Islands. As shown in **Error! Reference source not found.**, there a re three wind farms on Maui with a total capacity of 72 MW and an existing capacity of 100 MW of distributed rooftop sola photovoltaic system with an additional 14 MW approved for connection. This totals to 186 MW of variable renewable energy capacity on the grid, which is at or above the daytime load of the system at times. Since the system must run with at least approximately 60 MW of conventional generation in addition to the wind and solar generation, the wind power must be curtailed at times. The distributed rooftop solar system cannot be curtailed.

Figure A-20: Island of Maui – Current Renewable Resources

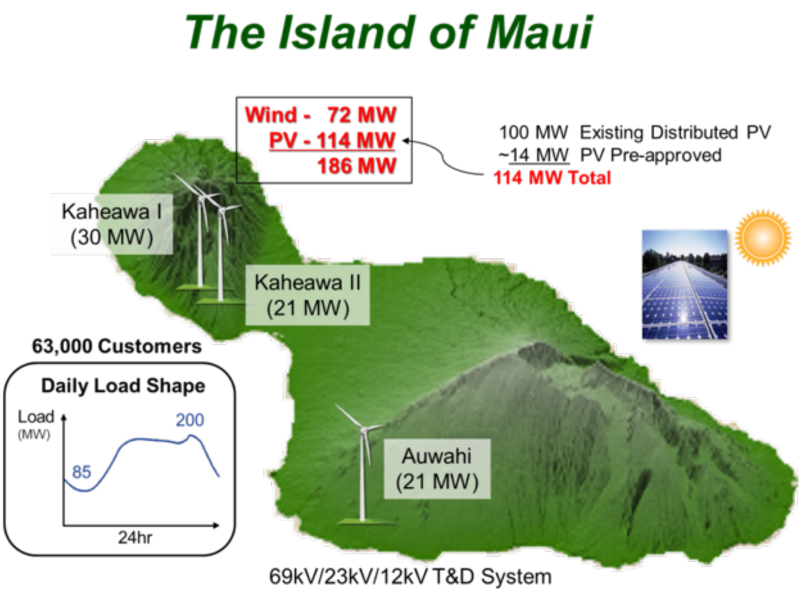
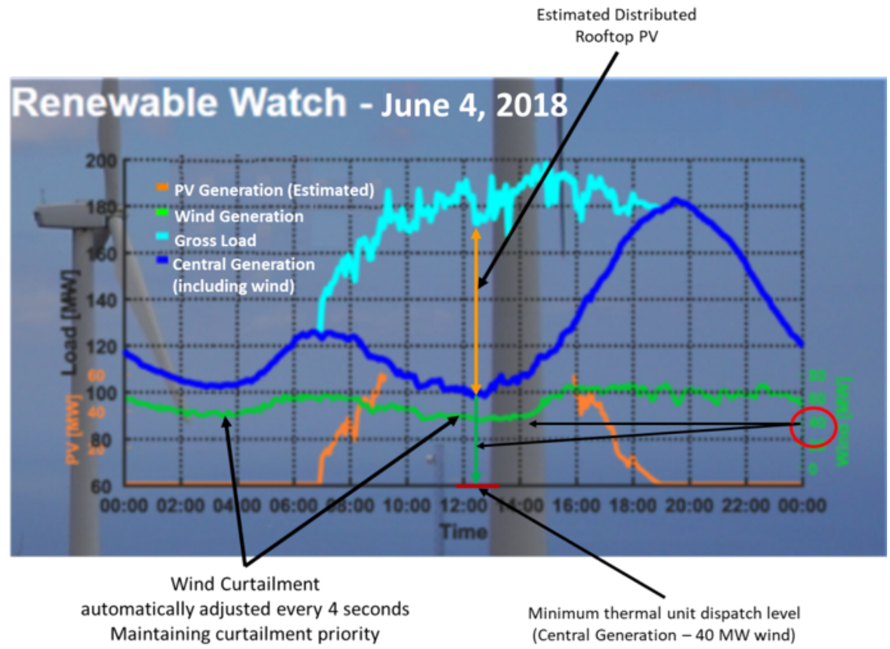



Figure A-21 shows an actual high wind and solar production day on the Island of Maui. The dark blue line shows the output of the output of large central generation (conventional generation and wind generation). The cyan line above the dark blue line shows the total estimated system load or the total generation on island, since total load and total generation must be equal. This is calculated by adding the estimated PV generation to the output of the large central generation. The green line is the wind power output and the orange line is the estimated PV generation. You can see in this graph that the wind power is curtailed during the minimum load period in the early morning hours and in the mid-day when the PV systems are at their maximum output. The wind farms are curtailed in the reverse of order of when they had their power purchase agreements approved. Since the Kaheawa II project was the last to get approved, it is the first to be curtailed. Next is the Auwahi project and last is the Kaheawa I project.

Figure A-21: High wind and solar energy day on Maui




Source: https://www.mauielectric.com/clean-energy-hawaii/integration-tools-and-resources/renewable-watch

To get the last wind farm financed and online, Kaheawa II, the curtailment risk for that project had to be quantified and economically mitigated. A detailed wind integration study was undertaken as a collaboration between Hawaiian Electric Company and its subsidiary Maui Electric Company, the Kaheawa II project, and GE Energy consultants.[25] Using the GE MAPS hourly production cost tool, custom intra-hour tools developed by GE, and GE's PSLF load flow and system dynamics tool, the integration of the Kaheawa II project was assessed assuming the Kaheawa I and AWE projects were in place. These tools were needed to determine the system's ability to accommodate the energy from the Kaheawa II project and the impacts the wind project and changes to power system operating practices would have on the reliability of the system from hourly to sub-second timeframes.

To conduct this analysis load and wind power profiles were needed for the system and each of the wind farms respectively. Actual wind power profiles were available from the Kaheawa I wind project that was in operation and this profile could also be used as a proxy for the Kaheawa II project since they are co-located. However, the AWE wind project was not in operation at the time of the study, so a wind profile had to be develop for this project using weather data and statistical manipulation to develop a high-resolution wind profile over the entire 2007 study year. It should be noted that

[25] N. Miller, D. Manz, S. Achilles, G. Hinkle, H. Johal, A. Panosyan, Rei Wen, "Report to HECO/MECO for KWP2 Wind Integration Study – Final Report", June 2010.

since this study was initiated in 2009, the influx of rooftop PV on the grid was in its early stages and no rooftop PV generation was assumed in this study.

The study found that the Kaheawa II project did not cause any issues for the existing system if the system maintained a regulating reserve of 50% of the first 30 MW of wind and 1MW for every 1MW of wind above 30 MW up to 50 MW. However, the existing system with the existing operating procedures could only accept a fraction of the Kaheawa II project's output due to excess energy available from all three wind farms and the fact that the Kaheawa II project would be the first wind project to be curtailed of the three wind projects on the island. For the scenario with all three wind farms in place, the Kaheawa II (KWP2) project is only able to deliver 25 GWh of the 93 GWh it had available that study year, see Table A-12 below.

Table A-12: Available and Delivered Wind Energy

| | | KWP1 | | ULU | | KWP2 | |
|---|---|---|---|---|---|---|---|
| Scenario | Wind Data | Available (GWh) | Delivered (GWh) | Available (GWh) | Delivered (GWh) | Available (GWh) | Delivered (GWh) |
| KWP1 | Historical* | 138 | 135 | | | | |
| KWP1 and KWP2 | Historical* | 138 | 135 | | | 97 | 59 |
| KWP1 and ULU | Estimated** | 133 | 129 | 108 | 78 | | |
| KWP1, ULU and KWP2 | Estimated** | 133 | 129 | 108 | 78 | 93 | 25 |

After this these results were determined several mitigation strategies were assessed to increase the ability for the system to accept more energy from the Kaheawa II project. The list of strategies considered is provided in

Table A-13 below.

Table A-13: Summary of strategies to increase wind energy delivered

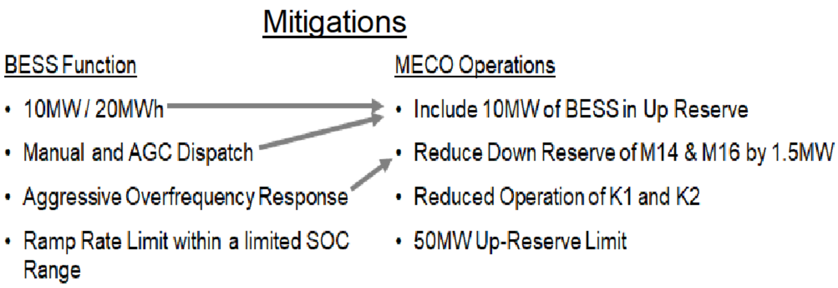
| # | Operational Change / Additional Equipment | Expected advantage | Risk | Observation |
|---|---|---|---|---|
| 1 | Reduce up reserve requirement | Reduce unit commitment in moderate/high load level. Reduce minimum power & cutailment | System frequency performance. Wind drop off events with insufficient reserve | Potentially most increased production benefit to WFs later in the curtailment order. |
| 2 | Reduce minimum operating power of thermal units carrying 6 MW of down reserve. | Increase WF production by 6MW during load low hours | Risk of units continuosly operating close to trip conditions | Depending on WF performing controls, most increased production benefit to WFs later in the curtailment order. |
| 3 | Storage (high energy) | Shifting injection of Plant 3 wind power | High energy/power ratings of storage | Limited number of hours in high wind days when additional power can be injected |
| 4 | Storage (lower energy) to provide up reserve | Reduce unit commitment in moderate/high load level | High energy/power ratings of storage | Potentially most increased production benefit to WFs later in the curtailment order. |
| 5 | Reduce system MR commitment rules | Increase WF production during low load hours | Insuffient MR to meet reliability requirements. Limitations to reliably cycle units. | Potentially most increased production benefit to WFs later in the curtailment order. |
| 6 | Additional fast start generation to reduce rotating reserve requirements | Reduce unit commitment in moderate/high load level | Permitting difficulties for thermal generation (biofuel may be option). Time required for implementation. Frequency performance for fast wind power variations (<10min) | Potentially most increased production benefit to WFs later in the curtailment order. |
| 7 | Wind production forecast | | | |
| 8 | Demand Side Management | | | |

The results of the study showed that the largest impact to increasing the acceptance of wind energy by the system was associated with the use a low energy battery storage system to reduce the commitment and dispatch of conventional generation on the system rather than trying to shift energy from off-peak to on-peak with a high energy battery used to shift energy.

Based on the results of this study, the utility agreed to change its operating procedures if and when the Kaheawa II wind farm installed and operated a 10 MW/20 MWh BESS to provide upward and downward reserves and frequency response. As a result, the Kaheawa II wind farm would be able increase its delivered energy to the system from 25 GWh to 42 GWh, see Table A-14. Although there was still significant curtailment risk, this was enough energy to finance the project.

Table A-14: Wind energy delivered with and without mitigations

| | Wind Energy Delivered (GWh) | | | | | | |
|---|---|---|---|---|---|---|---|
| | Scenario 1H | Scenario 2 | Scenario 2B | Scenario 1E | Scenario 3 | Scenario 4 | Scenario 4B |
| | Historical Wind Data | | | Estimated Wind Data | | | |
| | KWP1 | KWP1 + KWP2 | KWP1 + KWP2 (Mitigations) | KWP1 | KWP1 + ULU | KWP1 + ULU + KWP2 | KWP1 + ULU + KWP2 (Mitigations) |
| KWP1 | 135 | 135 | 136 | 131 | 131 | 129 | 132 |
| ULU | 0 | 0 | 0 | 0 | 79 | 78 | 91 |
| KWP2 | 0 | 59 | 77 | 0 | 0 | 25 | 42 |

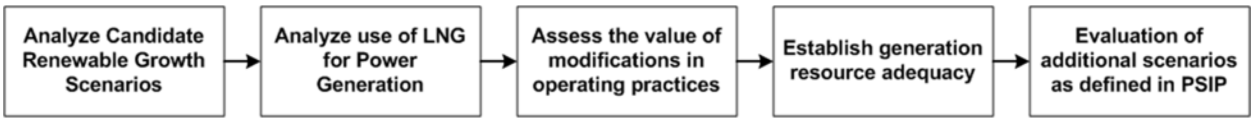



### Hawaii RPS Study[26]

The purpose of this study was to identify and evaluate cost-effective pathways that support the growth of renewables on O‘ahu and Maui with a goal of achieving the RPS targets. Unlike previous renewable integration studies conducted in Hawai‘i, this study was designed to be holistic in scope, encompassing a broad spectrum of power system operations, economics, and reliability impacts associated with high levels of renewable penetration. The study evaluated many different resource mixes including varying amounts of utility scale wind and solar, as well as increasing amounts of distributed rooftop solar PV. These resource mixes were evaluated with and without transmission and grid configurations that interconnect O‘ahu and Maui, as well as other off-island resources.

This study also evaluated the impact of recent and proposed changes to the power system, including conventional thermal plant additions and retirements, changing to the primary fuel to liquefied natural gas, and other changes being implemented by the utility. Wherever possible, this study quantified the impacts of these changes on the electric power system, with specific emphasis on renewable energy penetration, wind and solar curtailment, system economics, and grid reliability. The major project tasks are summarized in Figure A-22: Project Tasks and Analysis Flow Chart.

Figure A-22: Project Tasks and Analysis Flow Chart




The GE-MAPS production cost model was used to simulate the power system operation on an hourly, chronological basis over the course of the year. The model simulated the system operator’s (utility) commitment and dispatch decisions necessary to supply the electricity load in a least cost

[26] Hawaii Natural Energy Institute, GE Energy Consulting, “Technical Report - Hawaii Renewable Portfolio Standards Study”, https://www.hnei.hawaii.edu/sites/www.hnei.hawaii.edu/files/Hawaii%20RPS%20Study.pdf, May 2015.

manner, while appropriately reflecting transmission flows across the grid and simultaneously preparing the system for unexpected contingency events and variability. The chronological modeling is crucial to understanding renewable integration because it simulates hourly changes to electrical load and the underlying variability and forecast uncertainty associated with wind and solar resources.

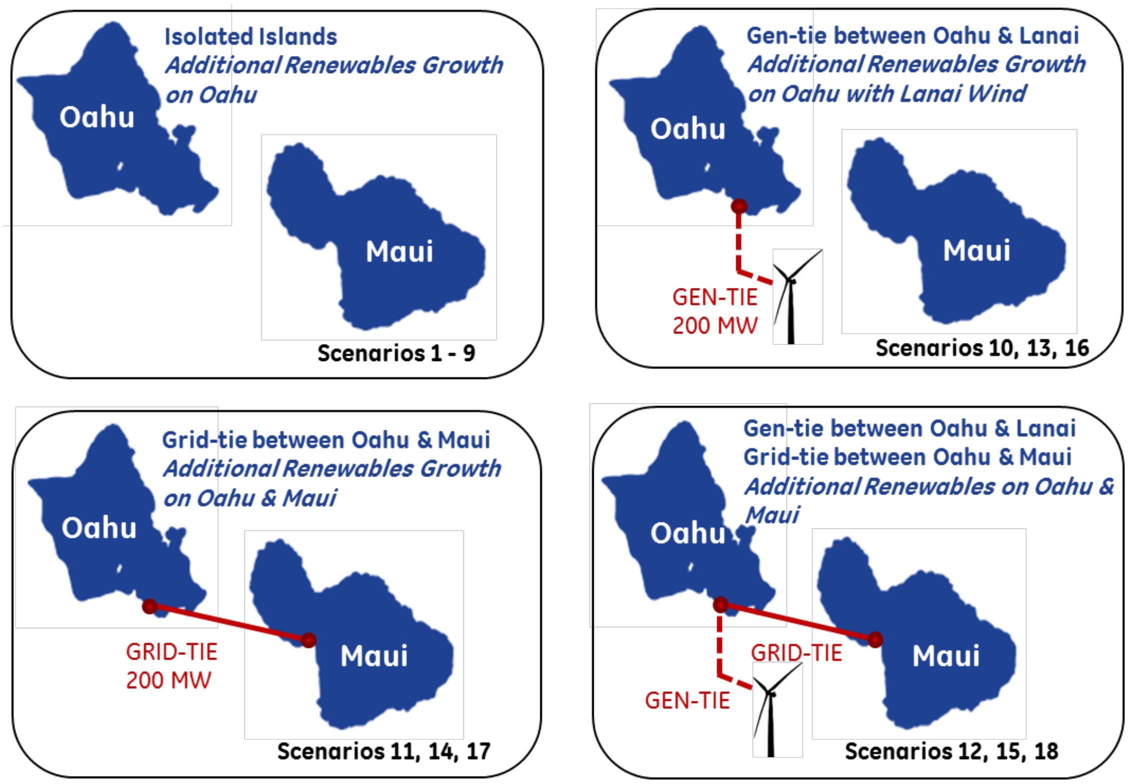
The GE-MARS reliability model was also used to simulate the power system on a chronological basis, but it focuses on generation resource adequacy of the system. Based on a full sequential Monte-Carlo simulation, the model evaluates probability of a loss-of-load event (grid blackout) given the generating capacity resources and emergency procedures available to the system operator. In addition, the model was used to calculate the capacity value (the ability of a resource to support grid reliability) of variable wind and solar resources.

The study was comprised of 18 renewable energy scenarios that evaluated a wide range of wind, utility scale solar PV and distributed rooftop PV additions to both the Maui and O‘ahu grids. The scenarios were selected to be similar in nature to recently proposed projects and offer a wide spectrum of different resource mixes and levels of available renewable energy. The scenarios were also selected to evaluate whether or not the future RPS targets are achievable utilizing wind and solar resources across O‘ahu and Maui. Figure A-23 provides schematics of the subsea HVDC cable interconnections for each scenario.

Table A-15: Scenario Matrix

| | Scenario | Oahu RE (MWs) | | | | Maui RE (MWs) | | | | Gen-tie (MWs) | Grid-tie (MWs) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Wind | Dist. PV | Central PV | Firm | Wind | Dist. PV | Central PV | Firm | Wind | Cable |
| Isolated Islands | 1 | 100 | 220 | 11 | 74 | 72 | 40 | - | 16 | 0 | 0 |
| | 2 | 100 | 220 | 11 | 74 | 72 | 40 | - | - | 0 | 0 |
| | 3 | 100 | 260 | 200 | 74 | 72 | 40 | -- | -- | 0 | 0 |
| | 4 | 200 | 260 | 200 | 74 | 72 | 40 | -- | -- | 0 | 0 |
| | 5 | 300 | 260 | 200 | 74 | 72 | 40 | -- | -- | 0 | 0 |
| | 6 | 100 | 360 | 300 | 74 | 72 | 40 | -- | -- | 0 | 0 |
| | 7 | 200 | 360 | 300 | 74 | 72 | 40 | -- | -- | 0 | 0 |
| | 8 | 200 | 460 | 400 | 74 | 72 | 40 | -- | -- | 0 | 0 |
| | 9 | 200 | 560 | 300 | 74 | 72 | 40 | -- | -- | 0 | 0 |
| Interconnected | 10 | 100 | 260 | 200 | 74 | 72 | 78 | 0 | -- | 200 | 0 |
| | 11 | 100 | 260 | 200 | 74 | 272 | 78 | 0 | -- | 0 | 200 |
| | 12 | 100 | 260 | 200 | 74 | 272 | 78 | 100 | -- | 200 | 200 |
| | 13 | 100 | 360 | 300 | 74 | 72 | 78 | 0 | -- | 200 | 0 |
| | 14 | 100 | 360 | 300 | 74 | 272 | 78 | 0 | -- | 0 | 200 |
| | 15 | 100 | 360 | 300 | 74 | 272 | 78 | 100 | -- | 200 | 200 |
| | 16 | 200 | 460 | 400 | 74 | 72 | 78 | 0 | -- | 200 | 0 |
| | 17 | 200 | 460 | 400 | 74 | 272 | 78 | 0 | -- | 0 | 200 |
| | 18 | 200 | 460 | 400 | 74 | 272 | 78 | 100 | -- | 200 | 200 |

Figure A-23: Cable Configurations by Scenario




Key Findings and Recommendations

The Hawaiian islands of O'ahu and Maui can achieve greater than 40% renewable energy penetration and can surpass the 2030 RPS goals. Certain modifications will be required to effectively accommodate these new renewable energy resources while lowering the cost of electricity and improving the reliability of the grid. In addition, the operational stability of the grid may also be challenged at these renewable energy penetration limits. To evaluate this impact, detailed stability analysis is currently underway on the high renewable energy scenarios assessed in this study. The findings from this analysis will suggest recommendations to improve the stability of the island grids and will be reported separately.

The following recommendations suggest different pathways that the island grids can take to improve the operational economics while being able to accommodate very high levels of renewable energy:

- Balanced growth of renewable resources: Diversity in generation resource mix will enable the island grids to continue increasing levels of renewable energy, at a lower cost of electricity while maintaining reliability. A balanced growth of available renewable resources will help to reduce the aggregate variability and intermittency, and the associated requirement for ancillary services on the grid.
- Improving grid flexibility: The island power grids, in general, require increasing flexibility to accommodate the intermittency and variability of wind and solar resources. New operational protocols and infrastructural upgrades will be required to ensure that the grid can respond effectively to meet the net load requirement and variability. This can be achieved through appropriate changes in the commitment and dispatch procedures, new infrastructure that will enable the existing generation to cycle up and down or on and off

daily, new controls that can enable the thermal generators to be turned down lower, and additional ancillary services.

- Natural Gas as the primary fuel for the islands: Delivering liquid natural gas can be a highly successful measure for lowering the cost of electricity as the islands transition to increased levels of renewable energy. The beneficial rate impact, however, depends critically on the contract price to bring LNG to the Hawaiian Islands. The delivered LNG price is dependent on the quantity in the contract and results of this analysis indicate that the consumption of natural gas can decrease by up to 33% as the renewable energy penetration reaches 50%. Under the current LNG price forecast (based on HECO's 2013 Integrated Resource Plan), the cost of electricity on the islands can be reduced by up to 28% under high renewable energy scenarios.
- Infrastructure for improving grid reliability: With the planned retirements of units in the coming years, the O'ahu grid reliability will be degraded from existing levels. New wind and solar generation will provide limited benefits in improving reliability and generation adequacy. The system planners must therefore evaluate other alternatives for meeting the reliability needs, including new thermal generation, energy efficiency, demand response, and possibly island interconnection. Meeting the 2020 energy efficiency targets or achieving the full demand response potential will enable the O'ahu grid to increase reliability levels well above the minimum requirement even after the proposed thermal generator retirements. However, if demand response is utilized heavily for reliability goals, it must be ensured to be available when needed and for the full duration of time required.
- Island interconnection facilitates increased renewable penetration and resource sharing: Interconnecting the islands will assist in sharing the resources more effectively: when O'ahu is short on generation, Maui may assist in shipping the needed MWs across the cable and vice versa. This will help to improve the reliability and generation adequacy of both O'ahu and Maui. In addition, the combined electrical grids will be able to accommodate higher levels of wind and solar energy by allowing the energy to flow through the cable. Diversity in generation resource mix and load profiles may further help in lowering the cost of operations. However, the interconnections require significant levels of capital expenditures and are therefore highly sensitive to financing costs, fuel price assumptions, and other economic variables.