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**SURINAME**

**SUPPORT TO THE INSTITUTIONAL AND OPERATIONAL STRENGTHENING OF THE ENERGY SECTOR**

**(SU-L1035)**

**TECHNICAL AND COST-BENEFIT ASSESSMENT OF THE POWER SYSTEM EXPANSION**

**REVISED REPORT**

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### I. Introduction

Suriname´s power sector consists of a number of individual power systems: the EPAR system, covering Paramaribo and the surroundings, the ENIC system, for New Nickerie in West Suriname and other smaller systems. These systems are operated by EBS (Energie Bedrijven Suriname) receiving electricity from Afobaka Hydro Power Plant (180 MW owned by SURALCO, Suriname Aluminum Company) through a 125 MW peak (80 MW average) contract to EBS, and from several diesel thermal power plants, owned by EBS (82 MW) and Staatsolie, the state oil company, (28MW).

EBS is a statutory corporation under the policy direction of the Ministry of Natural Resources (MNR) and with the monopoly in transmission and distribution of electricity. Due to an increase in residential demand and production activities, the electric power growth rate in Suriname is significant and the demand of electricity is expected to increase around 7% per year, posing additional pressure on EBS to cope with the growing demand in the short and medium-term. The level of power losses in the transmission and distribution grids is approximately 8.2%, which is not critical.

EBS faces several technical, operational and financial challenges which require Government’s intervention with adequate regulations and management practices to: (i) address the issue of electricity supply with new investments identified through the establishment of a planning procedure and an adequate model of contract for the purchase of reliable electricity; (ii) reduce generation costs from US¢ 20/kWh to US¢ 11/kWh achieving, in the midterm, an appropriate technological mix in the power generation capacity; (ii) address financial sustainability issues with the review of the tariff structure increasing the average electricity rate from US¢ 7.5/kWh in order to reflect the real generation, transmission and distribution costs[[1]](#footnote-1); and (iv) reflect adequate financial indicators in the electricity service.

To support those requirements, the Bank is studying a second Program Base Loan (PBL, SU-L1035) to the Government of Suriname with the objective to foster institutional development in order to facilitate an adequate development of the Power Sector with a view of having a commercially-based operation of the electricity service with clear economic and financial incentives.

This report contains a revision of a Cost-Benefit Analysis of the expansion program of the Surinamese power system done for the first Program Base Loan (SU-L1022) in 2012. Program benefits were estimated as the additional electricity supply, made possible with Program execution, valued at its consumers’ willingness to pay less supply costs. Investment, fuel, operation and maintenance costs were determined through an indicative planning procedure aiming to determine future (2013 – 2025) generation and transmission project expansions to conform the Program that minimizes total costs providing an adequate reliability to supply the expected future power demand.

The purpose of this report is to briefly describe the Generation / Transmission planning assumptions and models applied for the assessment of the expansion Program of the G-T Surinamese power system and to present the results obtained in a Cost-Benefit analysis for a base case including its sensitivity to variations in main parameters intervening in this task.

### II. Assumptions and Methodology

Based on the identified energy sector problems, the Government of Suriname has concluded that strengthen the electricity sector is a priority in the process to design and implement a sustainable energy development in Suriname. For this it has been structured a Policy Based Loan (PBL) Program with IADB support for the development of a financial and environmentally sustainable Power Sector Framework in order to guarantee economically and efficiently the future electricity provision in the country, among others. Main objectives of the PBL Program are the execution and application of several legal, financial, corporate and environmental components, all of them mainly focused to reinforce the adequacy of the Generation – Transmission (G-T) system expansion Plan after 2015, being this one of its key products considered in the policy matrix.

The Cost Benefit Analysis was focused in the evaluation of this Plan as a main product to be obtained from the PBL Program. It considers investment, O&M and fuel costs of the G-T expansion requirements compared to its benefits, that were evaluated considering that without the PBL Program it would not be possible to overcome significant difficulties that are in place today to optimize the G-T system expansion required to supply the Surinamese electricity demand coverage and growth after 2015, losing the overall economy the benefits associated to the expected additional electricity demand increases expected after this year.

### II.1 Program description and evaluation approach

The Generation – Transmission Program evaluated includes the following generation and transmission projects identified, preliminarily and in a broad base, as participants in the path of minimum cost expansion of the Generation - Transmission system of Suriname.

Total generation capacity included in the Program is 486 MW representing USD 372.4 millions in investment costs during 2013-2025.

**NEW POWER PLANTS: BASIC CHARACTERISTICS AND COSTS**



The table does not includes the Moengo (NewM) power plant (85 MW) nor the Wageningen Bagasse power plant (9 MW) that were considered in an alternative base scenario that assumes the Wageningen – Nickerie interconnection and the supply from Moengo of a future gold industry (Newmount) consuming 70 MW.

The power system expansion under the Base Scenario also requires the following transmission projects operating at 161 kV and 33 kV, representing USD 349.4 million in investment costs during 2013 – 2025.

NEW TRANSMISSION SYSTEMS: BASIC CHARACTERISTICS AND COSTS



The table does not include the transmission projects required to supply the Newmount gold mine nor the Wageningen – Nickerie interconnection.

The existing G-T system provided the power service until 2012, when 1,325.7 GWh[[2]](#footnote-2) were sold in Suriname. After this year, the assumption is that without the Program it would not be possible to supply additional power sales with an acceptable reliability. In this way, the increase of electricity sales after 2012 will be directly associated to the Program.

Next table summarizes the estimation of electricity sales “with” and “without” the Program, constituting the starting point of the estimation of the Program’s benefits.

**SURINAM: ELECTRICITY SALES “WITH” AND “WITHOUT” THE PROGRAM (GWH)**



Transmission losses were estimated in the simulations and the distribution losses were calculated assuming that total losses will represent 8.2% of total demand, similar to recent historical values. Program’s benefits evaluation required the forecast of the electricity demand in Suriname and the application of a methodology to evaluate the consumer’s willingness to pay of the electricity sales associated to the Program. Program’s cost evaluation required the disaggregation in time and in space of the forecasted demand and the application of a Generation – Transmission planning procedure to simulate future power generation dispatch. Also a load flow analysis was required to verify reliability of supply and to determine investment, fuel and O&M system costs. For this purposes the SDDP model was applied. Next sections presents the methodologies related to: i) demand forecasts, ii) benefit estimations, iii) G-T system operative simulations and costs estimations (SDDP model application).

### II.2 Demand forecast

### II.2.1 Historical electricity consumption

Next table shows the national growth of the electricity consumption in kWh for Suriname, starting from the year 2000.

**SURINAME: HISTORICAL ELECTRICITY DEMAND**



Source: EBS

From table the average growth of the electricity consumption over the past 12 years is 6.3%. Annual demand growth in EPAR area (6.4%) is higher than in the Districts (4.0%), being Nickerie demand growth the most significant. The demand of Rosebel Goldmines is not included in the table.

Next graph describes electricity usage in Suriname (48% residential, 34% industrial and 18% other sectors).



Source: EBS

### II.2.2 Energy demand forecasts

Energy demand forecasts were estimated using future annual average growths similar to historical growth. It was considered that future EPAR demand covers the specific loads of the refinery expansion and the governmental housing programs. However, the incremental demand of the gold industries (Rosebel and Newmont) were estimated separately.

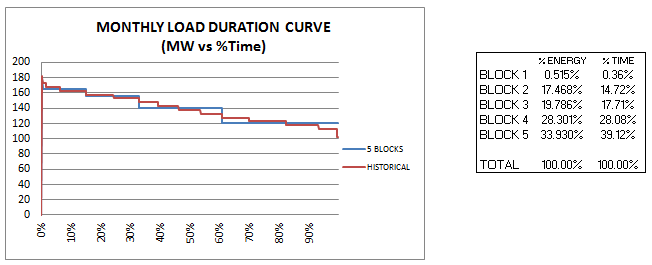
Next table summarizes the forecasted energy demand for each of the systems and for the gold mines (the demand for the gold industry was estimated with peak demand reaching 50 MW for Rosebel in 2017 and 70 MW for Newmont in 2019 and with 0.84 as load factor).

**ENERGY DEMAND FORECAST (GWH)**



**II.2.3 Load duration curve and peak demand**

Peak demand was estimated using the historical monthly load duration curve represented by 5 load blocks (with peak duration representing the 0.36% of time). Next graph illustrates the monthly load duration curve estimated for Epar system, based on the 10 minute demand statistics of May 2012.



The simulations of generation dispatch required the distribution of the annual energy demand by blocks and by months . Monthly distribution factors of energy demand were estimated based on 2011 historical energy demand distribution and then the Block distribution factors for each month of the year were obtained using the typification of the monthly load duration curve.

Next table shows the distribution factors applied in the study and the verification of a forecasted peak load of 200 MW for 2012 in September (associated to a total Epar forecasted energy demand of 1,248.4 GWh for this year).

**POWER DEMAND DISTRIBUTION FACTORS**



### II.2.4 Demand distribution by substations

For generation – transmission planning purposes it was required to forecast demand by systems and for all Epar substations. For this purpose the statistics of peak demand for Epar substations of 2011 was used to distribute total forecasted demand for this system. Demand forecasts for each district were also maintained separately for each system. Also, the 50% of demand forecast obtained for Nickerie was assigned to each of the two substations considered in this area (Clara and Soekramsingstraat). Next table summarizes the load distribution in Epar substations.

**EPAR: DEMAND DISTRIBUTION BY SUBSTATIONS (MW)**

**6 kV**



**12 kV**



### II.3 Benefit estimations

EBS faces several technical, operational and financial challenges which require Government’s intervention with adequate regulations and management practices to, among others, address financial sustainability issues with the review of the tariff structure adapting the average electricity rate of around US¢ 7/kWh in order to reflect the real generation, transmission and distribution costs. Current power service in Suriname implies significant subsidies to final consumers that are basically assumed by the State. Such subsidies constitute financial transferences among national agents’ not constituting costs or benefits from the standpoint of the national economy.

The Generation / Transmission expansion program will provide an increment of electricity consumption in Suriname, given that without this program EBS would have to restrict power supply up to the current Generation / Transmission capacities. This incremental consumption is the base for benefit estimations and main assumption of the study was the consideration of a referential "cost effective average tariff" of US$ 162/MWh to final consumers (see ANNEX 1). From the country´s perspective, main economic benefits associated to this program will consist in: a) the increase of EBS power sales valued at its Generation – Transmission economic tariff, plus b) its associated consumer's surplus in the residential sector as permitted by the higher capacity provided by the program[[3]](#footnote-3).

Benefits a) were estimated in US$ 132/MWh for EPAR system and US$ 130/MWh for the gold industries as presented in ANNEX 1.

Benefits b) were estimated from the increase of power consumption in EPAR system, excluding the demand in gold industries. Next figure illustrates the demand curve in a future time (t=i). From a user´s perspective, net benefits associated to the increase of electricity consumption are estimated as the consumer´s surplus given by area ABC.

**BENEFIT ESTIMATION OF ADDITIONAL RESIDENTIAL CONSUMPTION**



In the graph Pi correspond to the cost effective tariff (US$ 162/MWh). Consumer's surplus benefits would represent around US$ 135/MWh under the assumption that without the G-T expansion program the 100% of incremental demand in new areas would not be supplied. Also, institutional subsidies to the power service would be around US$ 87/MWh under the assumption of maintaining the existing average tariff P0 of US$ 75/MWh to final consumers.

Consumer's surplus benefits associated to the G-T expansion program were estimated from the definition of Price – Elasticity (*Ε* ): it follows that the derivative of Price p with respect to the quantity q at the point Pi and quantity Qi is given by:

*dp/dq = Pi/Qi x 1/Ε*

The price that a consumer is willing to pay for a quantity *Qi - Δq* is given by:

*Pmi = P0 – dp/dq x Δqi*

And the consumer’s surplus is calculated as:

Consumer’s surplus = (*Pmi* – *P0*) x *Δqi / 2*

In the equation Δqi is the increase of electricity consumption in year i associated to the projects (Δqi = Qmi - Qi), Pmi is calculated with P0 (US$ 75/MWh), E (-0.6) and the percentage Ri (100%) of additional electricity consumed attributable to the G-T program as Pmi = P0 x (1 - Ri/E). It was applied a Price-Elasticity of -0.6, according typical estimations of similar electricity markets in Latin America[[4]](#footnote-4).

### II.4 G-T System operative simulations (SDDP model application)

The determination of the investment, operation, maintenance and fuel costs related to a reliable supply of the increment of electricity consumption in Suriname required the application of a Generation/Transmission planning procedure, mainly focused to: a) identify the most efficient generation and transmission projects required to supply demand, and its execution itinerary in order to estimate the flow of investment costs, and b) estimate the future power dispatch in the power systems from to support the fuel and O&M costs estimations.

The SDDP model was applied to simulate future G-T system operation and expansion, to verify both the expansion requirements as well as the reliability of power supply (on monthly basis and in each of the buses attending local demands). The simulations also permitted to obtain future dispatch of power plants and load flows in the transmission links from which transmission losses, fuel and O&M costs were obtained. These aspects are presented in this section, including the description of the main components of the generation and transmission systems.

### II.4.1 Existing power plants

Next table summarizes the basic characteristics of the existing generation capacity in Suriname.

**EXISTING POWER PLANTS**



Fuels used and fuel costs are as follows.



Total installed capacity of Suriname adds today 274.3 MW (assigning 125 MW to Afobaka hydroelectric power plant, according the EBS-SURALCO power purchase contract).

### II.4.2 Future and potential power plants

Next table summarizes main characteristics of future power plants considered for the power sector expansion in Surinam (mostly represented by diesel gensets).

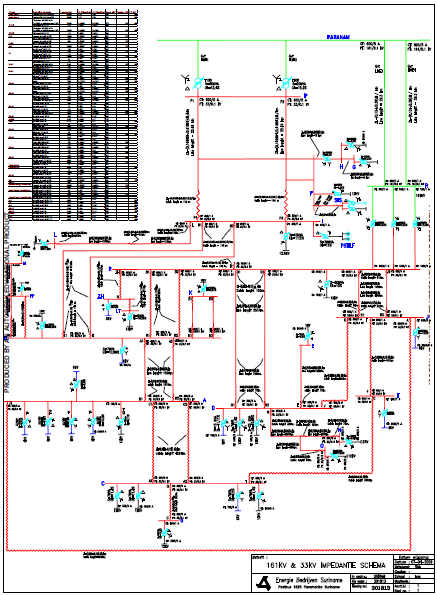
**FUTURE POWER PLANTS**



Fuels used and fuel costs are the same as presented for the existing power plants.

### II.4.3 Existing transmission system

The Epar transmission and subtransmission system is conformed at 161 kV and 33 kV. Next graph illustrates the one-line diagram of the system.



For power system (generation – transmission) planning purposes the Epar system and the rest of small systems of Suriname were represented by 96 buses and 50 transmission, subtransmission and distribution links, that are presented in next tables.

**SURINAMESE TRANSMISSION SYSTEM: BUSES**



**SURINAMESE TRANSMISSION SYSTEM: TRANSMISSION & DISTRIBUTION LINKS**



### II.4.4 Generation / Transmission system expansion analysis

The determination of the investment, operation, maintenance and fuel costs related to a reliable supply of the increment of electricity consumption in Suriname required the application of a Generation/Transmission planning procedure, mainly focused to: a) identify the most efficient generation and transmission projects required to supply demand, and its execution itinerary in order to estimate the flow of investment costs, and b) estimate the future power dispatch in the power systems from to support the fuel and O&M costs estimations.

The SDDP model was applied to simulate future G-T system operation and expansion, to verify both the expansion requirements as well as the reliability of power supply (on monthly basis and in each of the buses attending local demands). The simulations also permitted to obtain future dispatch of power plants and load flows in the transmission links from which transmission losses, fuel and O&M costs were obtained. These aspects are presented in this section, including the description of the main components of the generation and transmission systems.

It was applied a Generation / Transmission planning process to obtain a first approximation of the minimum cost (Investment - Fuel - O&M costs) system expansion that would provide adequate reliability for the Surinamese electricity supply during 2012 – 2025. The SDDP model was applied in a sequential manner to identify the required expansion itinerary of new power plants an lines and a final run permitted to verify the adequacy of the future demand/supply balance on monthly basis and considering optimal power dispatch with transmission losses and constraints imposed by the transmission links (represented by maximum transmission capacities in each link and load flow Kirchhoffs Laws through DC simplified load flows).

This section presents a brief description of the model and its application procedure and the results obtained for the prospective Demand/Offer balance in the Surinamese power sector.

### a) SDDP model

SDDP (Stochastic Dual Dynamic Programming) is a hydrothermal dispatch model with representation of the transmission network and is used for short, medium and long term operation studies. The model calculates the least-cost stochastic operating policy of a hydrothermal system, taking into account the following aspects:

|  |  |
| --- | --- |
| seta | Operational details of hydro plants (water balance, limits on storage and turbined outflow, spillage, filtration etc.); |
| seta | Detailed thermal plant modeling (unit commitment, generation constraints due to "take or pay" fuel contracts, concave and convex efficiency curves, fuel consumption constraints, bi-fuel plants etc.); |
| seta | Representation of spot markets and supply contracts; |
| seta | Hydrological uncertainty: it is possible to use stochastic inflow models that represent the system hydrological characteristics (seasonality, time and space dependence, severe droughts etc.) and the effect of specific climatic phenomena such as the El Niño; |
| seta | Detailed transmission network: Kirchhoff laws, power flow limit in each circuit, losses, security constraints, export and import limits for each electrical area etc; |
| seta | Load variation per load level and per bus, with monthly or weekly stages (medium or long term studies) or hourly stages (short term studies). |

In addition to the least-cost operating policy, the model calculates several economical indexes such as the spot price (per submarket and per bus), wheeling rates and transmission congestion costs, water values for each hydro plant, marginal costs of fuel supply constraints and others.

The SDDP model uses a new solution methodology called stochastic *dual* dynamic programming, developed by PSR (Power System Analysis Inc., from Brazil). This methodology represents the future cost function of traditional Stochastic Dynamic Programming as a piecewise linear function. Because of this feature, it is not necessary to enumerate the combinations of reservoirs levels, which allows the determination of the stochastic optimal solution for systems with a large number of hydro plants.

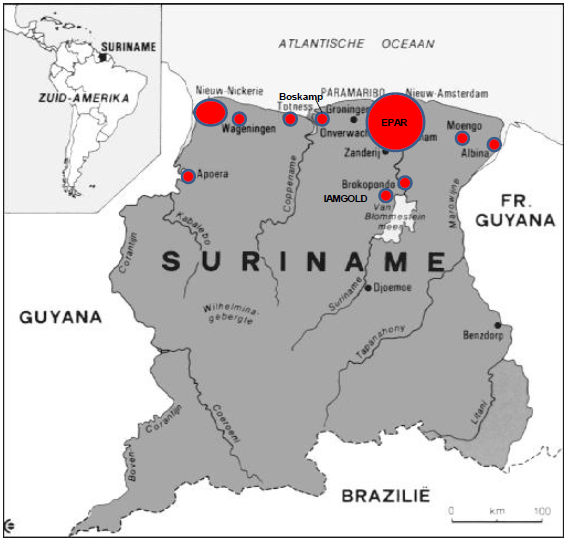
All the detailed results of the model SDDP are written to \*. csv format files. These files are managed by a graphic interface which produces Excel files with the desired results. The main SDDP results are:

|  |  |
| --- | --- |
| seta | operative statistics: hydro and thermal generation, thermal operation costs, energy interchange, fuel consumption, deficit risks and energy not supplied; |
| seta | short run marginal costs (spot prices) for each submarket and for each bus; |
| seta | marginal capacity benefits: measure of the operational benefit of reinforcing the installed capacity of a thermal plant, the turbine limit of a hydro plant or the storage capacity of a reservoir. These indices are used to determine cost-effective system reinforcements. |

See ANNEX 3 for more details about the SDDP model.

### b) Generation / Transmission system expansion and operative simulations

The Suriname power sector consists of a number of individual power systems. Some of these systems are interconnected while others are operated as an electrical island. The following Figure provides a schematic overview of the different systems currently in operation.



The *EPAR system* for Paramaribo and the surroundings, reaching as far as the Ocean in the North, Stolkertsijver in the District of Commewijne in the East, Carl Francois in the District of Saramacca in the West and The Zanderij (Airport) area in the South. The EPAR system has by far the highest consumption of electric power in Suriname (total demand in this system was 1,167 GWh in 2011, see ANNEX 4 containing the G-T diagram of this system);

The *ENIC system* for New Nickerie in West Suriname, and the surroundings reaching as far as Groot Henar in the West (total demand in this system was 68 GWh in 2011);

The *Rural District* Power Systems, each operating as an isolated power system with one or more Diesel Generator Sets in a local power house and located at: Albina, Moengo, Boskamp, Coronie, Wageningen, Apoera (total demand in these areas was 29 GWh in 2011);

The *Rosebel Gold Mines* where the Gold Mine operations of IAMGOLD in the Brokopondo district are supplied with electric power via a dedicated 161 kV overhead power line coming from Afobaka Hydro power Plant, built and owned by IAMGOLD (total Rosebel demand was 193 GWh in 2011);

The *Brokopondo* Distribution system feeding some villages in the Brokopondo district from the 13.8 kV system at the Afobaka Hydro Power Plant and several small power systems exist in interiorof Suriname, which systems are owned and operated by the Department for Rural Energy of the Ministry of Natural Resources (DEV).

Two indicative generation – transmission expansion scenarios were identified of interest for the simulations, as follows:

a) Base Scenario A: with base demand forecast of 7% annual increase and including the development of the generation capacity in Epar system (with new power plants based in HFO in Saramacastraat, Statsolie and Het Vertrouwen) and significant transmission expansions to supply the new demand of the future Newmont gold industry (estimated for 2015 and located in the Southeast of the country) from Epar and Mongeo systems (with new generation based on HFO in this area) and the interconnection of Nickerie and Wageningen systems associated to new generation capacity based on bagasse located in Wageningen, and

b) Base Scenario B: also with base demand and the same new power plants in Epar system but not considering the transmission and generation investment to supply the Newmont gold industry, without the interconnection of Nickerie and Wageningen systems and with the new bagasse power plant substituted by new power plants in Nickerie based on HFO.

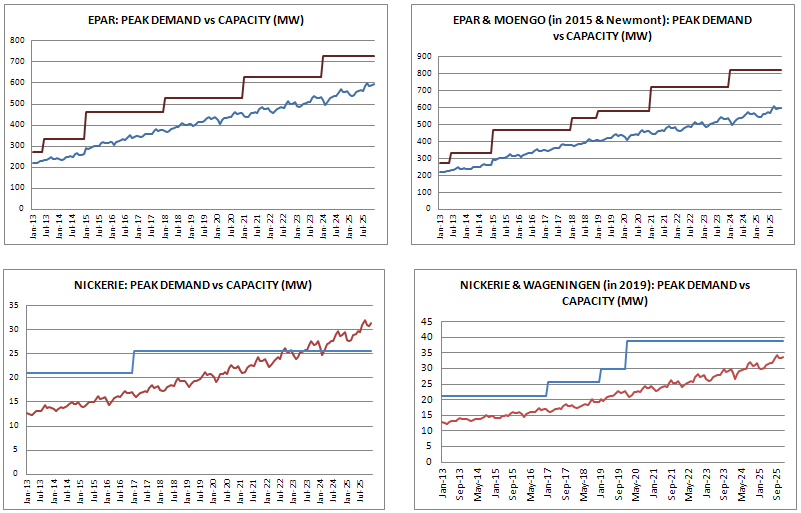
These two scenarios were constructed first by selecting the itinerary of the new power plants to supply demand in Epar and Nickerie systems with 15-20% of capacity reserve and then obtaining the timing for the required transmission and subtransmission expansions (at 161 kV and 33 kV) in the Epar system to guarantee the electricity supply in all substations, considering the new transmission projects identified for the systems. Also the transmission expansions to connect Epar & Mongeo with Newmont (161 kV) and Wageningen with Nickerie (33 kV) were programmed in time. In both scenarios the Apoera, Coronie and Albina small systems remain isolated and self sufficient in power generation.

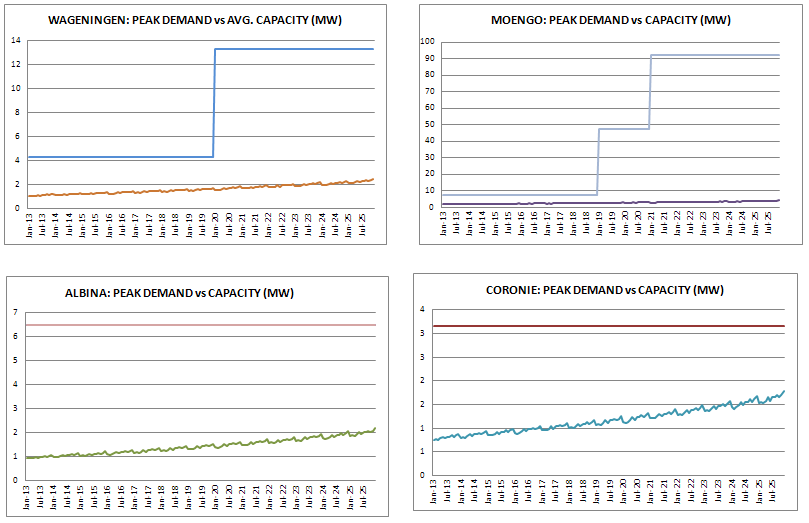
The simulation of these two scenarios was done with the SDDP model and using a data base constructed with EBS to represent future demand during 2012-2025 (by months and for five demand blocks) and all existing and future power plants, transmission lines and subtransmission substations up to the level of 12 kV and 6 kV. The Epar (including Rosebel and Newmont loads) and Nickerie systems were represented separately and the Districts system considered the Wageningen, Coronie, Apoera, Mongeo and Albina loads. The simulations represented the minimum cost of power dispatch (including transmission losses) for the system considering 27 power plants, 96 buses and 90 transmission links.

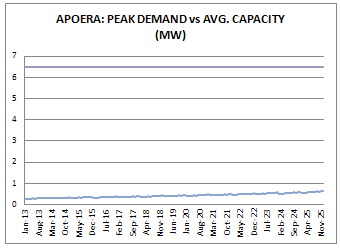
The prospective and the electricity Demand/Offer forecasts obtained from the simulation of these two scenarios are presented next. Those results constitute the support for the Cost-Benefit evaluations presented in chapters III, IV, V and VI.

### i) Base Scenario A

Next graphs summarize the peak demand forecasts and generation expansion programs obtained for each system under this scenario. Epar & Moengo and Nickerie & Wageningen are also presented in individual graphs corresponding to the interconnected systems.







Next graph present the marginal cost of demand forecast obtained for the main systems, ranging around 130 – 150 USD/MWh.



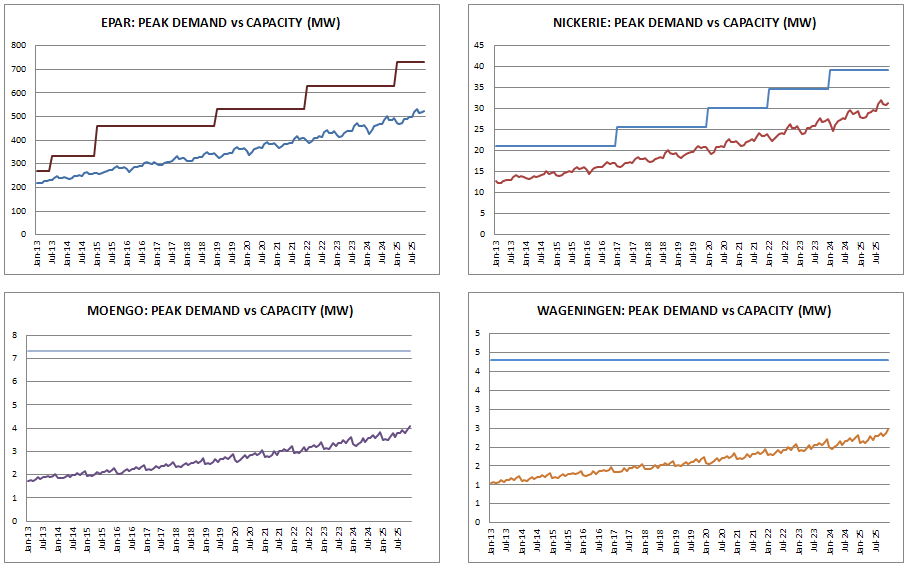
The aggregation of all loads, losses and dispatched power in Surtiname is presented next in the electricity balance forecast.

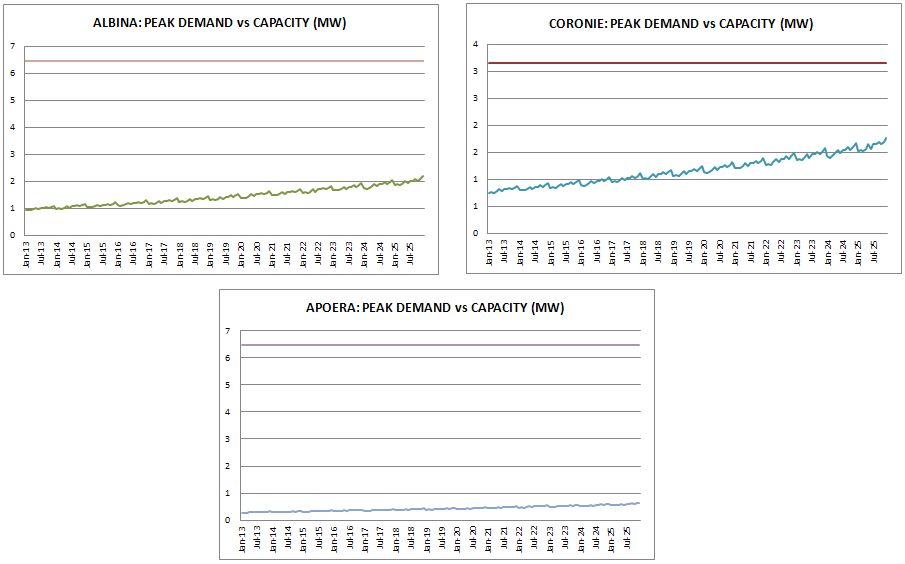


### 

### ii) Base scenario B

Next graphs summarize the peak demand forecasts and generation expansion programs obtained for each system under this scenario.





Next graph present the marginal cost of demand forecast obtained for the main systems, ranging around 130 – 150 USD/MWh.



The aggregation of all loads, losses and dispatched power in Suriname is presented next in the electricity balance forecast.



### III. Economic Benefits

Next tables summarize the forecasted Program’s demand and benefit estimation (consumer’s surplus and generation- transmission benefits) associated to the two scenarios evaluated. The difference among the two scenarios corresponds mainly to the inclusion of the Newmont load in scenario A.

**BASE SCENARIO A: PROGRAM DEMAND AND BENEFITS (GWH)**



**BASE SCENARIO B: PROGRAM DEMAND AND BENEFITS (GWH)**



### IV. Economic costs

Next tables summarize the total cost itinerary associated to the two scenarios evaluated (see ANNEX 5 contained the detailed cost itinerary for each scenario).

**BASE SCENARIO A: COST ITINERARY (USDM)**



**BASE SCENARIO B: COST ITINERARY (USDM)**



Total costs are much higher under scenario A than in B due mainly the higher requirements in power plants and transmission systems to attend the Newmont load. Also fuel costs are significantly increased to attend this load.

### V. Economic returns

Next table contains the itinerary of Benefits and Costs associated to the G-T expansion Program under Base Scenario A. The economic rate of return (ERR) is 17.2% and the present value of its net benefits (at 12% discount rate) is USD 272 millions. As presented before, this scenario is very intense in transmission investment and an alternative scenario was evaluated that is presented next.

**BASE SCENARIO A: COST BENEFIT ANALYSIS**



Next table contains the itinerary of Benefits and Costs associated to the G-T expansion Program under Base Scenario B. The economic rate of return (ERR) is 23.3% and the present value of its net benefits (at 12% discount rate) is USD 467 millions, much higher than net benefits under Base Scenario A. For this reason this scenario was selected as the reference scenario base on which the sensitivity analysis is presented in next section.

**BASE SCENARIO B: COST BENEFIT ANALYSIS**



### VI. Sensitivity analysis

This section contains the results obtained in the sensitivity analysis of the Cost - Benefit evaluation to the following main aspects: a) expansion program geographical coverage, b) demand forecasts, c) fuel prices, c) investment costs, and d) benefits estimations. Next table contains the results obtained.

**SURINAME: G-T EXPANSION PROGRAM SENTITIVITY ANALYSIS**



The sensitivity analysis indicates that the high cost of the transmission expansions required to supply the Newmont load and of the Wageningen – Nickerie interconnection may offset the benefits that could be obtained from the supply of the demand of the new gold mines and from low cost bagasse generation.

The results also illustrates that lower demand forecasts (with 5% yearly growth), 20% increase in fuel prices, 20% increase in investment costs or 20% decrease in the benefits estimations will still permit significant net economic benefits from the G-T expansion program required to guarantee the electricity supply in the country. Opposite changes in those parameters will improve significantly its economic indicators.

VII. Conclusions

Benefits associated to the G-T expansion Program were revised including the following main considerations: a) and updated average "cost effective tariff" of USD 162/MWh (including USD 132/MWh of Generation & Transmission cost) instead of USD 160/MWh (and USD 125/MWh of Generation & Transmission cost) for EPAR system; b) real EBS electricity sales in 2012 of 1,325.7 GWh instead of the 2012 forecasted sales of 1,399.8 GWh as reference sales that could be supplied without the G-T Program; c) incremental electricity sales assumed for new residential areas and consumer's surplus benefits estimated with -0.6 price-elasticity for residential consumption instead of -0.3 price-elasticity for total existing market; and c) generation-transmission benefits revised with new tariff assumptions. Costs were revised including: i) the installation of 63.0 MW instead of 31.5 MW in BEM power plant in 2013, and ii) the revision of O&M costs considering this additional capacity. Present value of Benefits and Costs at 12% discount rate were calculated using 2013 as reference year instead of 2012. Results obtained for the economic evaluation of the reference G-T expansion program indicated: a) the increment from USD 1,848 to USD 1,944 million of the present value of Benefits; b) the increment from USD 1270 to USD 1477 million of the present value of costs; c) a variation from USD 588 to USD 467 million in the present value of net benefits; and d) a variation from 26.0% to 23.3% in the economic rate of return from 26.0% to 23.3%

These revisions, however, do not change the conclusions obtained in the former evaluation which are presented next.

* The power generation – transmission planning activity in Surinam requires support to identify the best solutions of an economically efficient power system expansion. A power planning procedure could be institutionalized based on the application of appropriated technologies and models. The experience obtained in this study indicates that models as the SDDP (or preferable, the Optgen) could be very helpful for this task.
* The generation options to guarantee future electricity supply are mainly related to high cost liquid fuels and efforts should be done to identify additional options (mainly related to hydro, coal or gas technologies) aiming to reduce future electricity costs.
* Transmission requirements are also significant in Epar system and its study and evaluation also imply significant efforts to identify the appropriate transmission/subtransmission expansions in this system.
* Other isolated systems are still very small and its interconnection to the main grid may not be economical yet.
* The supply of the Newmont gold mine load from Epar and Moengo systems may justify its interconnection, but it would require important transmission investments that should be evaluated in order to verify its eventual economic attractiveness.
* The interconnection of Wageningen and Nickerie systems to develop low cost bagasse generation would also require significant transmission investments that should be evaluated to verify its economic attractiveness.
* From a national perspective, the Surinamese generation – transmission system expansion is economically attractive to supply future demand increase in the country and, conceived with minimum cost criteria, will provide significant economic returns. However, given the current institutional, financial, electricity prices and regulatory status, there are significant risks that the real future system expansion would not be the optimal, implying a decrease of its net economic returns for the country.

**ANNEX 1**

**ESTIMATION OF THE GENERATION / TRANSMISSION ECONOMIC TARIFF**

**AND THE "COST EFFECTIVE TARIFF" IN EPAR SYSTEM**

A "Cost Effective Tariff" for final users in EPAR system was estimated considering an average of 36% of hydroelectric energy supply (at USD 70/MWh representative of expected purchase prices) and the remaining 64% with the unitary generation cost of Diesel motors with heat recovery using Heavy Fuel Oil, on the basis of the following components:

A. Fixed Tariff, consisting of: i) Fixed Operations & Maintenance cost: USD 26.3/kW/year, and ii) Investment cost: USD 1,200/kW

B. Variable Tariff, consisting of: i) Variable Operations & Maintenance cost : USD 0.009/kWh, ii) Fuel cost (HFO): 14.5 US$/MBTU, iii) Heat Rate of 7.195 BTU/KWH ; iv) Lubricants cost: US$ 2.35/MWh v) Variable Costs of US$ 9/MWH.

The generation cost was estimated in USD 122/MWh for EPAR system and the cost effective tariff in US$ 162/MWH, including a transmission tariff of USD 10/MWh and a distribution tariff of USD 30/MWh based on the experience in other similar systems, as follows:

COST EFFECTIVE TARIFF IN SURINAME



The economic Generation – Transmission tariff would be USD 132/MWh in EPAR system. Given its higher load factor, for the gold industries was estimated in USD 130/MWh.

**ANNEX 2**

**SURINAMESE SYSTEM: LINE IMPEDANCES**



ANNEX 3

MODELO SDDP

A continuación se presenta una descripción general del modelo SDDP, la cual ha sido extractada de la documentación informativa sobre el mismo preparada por la firma Power Systems Research Inc.

1. MARCO CONCEPTUAL

1.1 Objetivos de la Planificación Operativa

El objetivo básico de la planificación operativa de un sistema hidrotérmico es determinar metas de generación para cada planta, a cada etapa, que suministren la demanda y minimicen el costo operativo promedio a lo largo del período de planificación. Este costo se compone del costo variable de combustible de las plantas térmicas, de la compra de energía de otros sistemas, y del costo asignado a las interrupciones del suministro de energía, o sea, el costo de déficit.

Además de este objetivo básico, los modelos de planificación operativa se utilizan para un amplio rango de estudios de planificación, que se ilustran a continuación:

*informaciones sobre consumo de combustible* - a través de la simulación operativa del sistema para distintos escenarios de hidrología y demanda, se estiman el promedio y varianza del consumo de combustible, y los valores extremos de este consumo. Esta información es importante para la programación financiera de la empresa.

*optimización de los mantenimientos* - para cada cronograma tentativo de mantenimiento, se optimiza la política operativa, se evalúan los costos operativos resultantes, y se escoge el cronograma que minimice estos costos.

*estudios de políticas comerciales* - los modelos de política operativa se utilizan para evaluar el efecto de contratos de intercambio con sistemas vecinos. Para cada alternativa de contrato, se calcula la política operativa, y se evalúan los ingresos resultantes de la venta de energía, su varianza, valores máximos y mínimos etc.

*estudios de política tarifaria* - además de la política óptima, los modelos de planificación operativa calculan los *costos marginales* del sistema, esto es, la variación del costo operativo promedio con respecto a variaciones incrementales de la demanda en cada etapa. Esta información es básica para estudios de política tarifaria, la determinación de precios de intercambio con los sistemas vecinos, y la determinación de tarifas de peaje por el uso del sistema de transmisión de la empresa por terceros.

*estudios de política de racionamiento* - los modelos de planificación operativa representan el efecto de distintas políticas de racionamiento de energía, en términos de duración, profundidad e impactos económicos y financieros.

*estudios de manejo de la demanda* - para cada programa candidato de manejo de la demanda, se calculan los impactos en términos de reducción de los costos operativos. Estas reducciones se comparan entonces con los costos de implantación de los programas, y se escoge el programa más rentable.

*realimentación al planeamiento de la expansión* - además de los costos marginales asociados a la variación de la demanda, los modelos de planificación operativa calculan los costos marginales de capacidad, esto es, la reducción del costo operativo promedio con respecto a refuerzos incrementales de la capacidad de cada equipo de generación o transmisión. La comparación de estos beneficios incrementales con los costos incrementales de inversión de cada equipo permite identificar los candidatos más rentables para la expansión del sistema.

1.2 Incertidumbre en los Parámetros

La política operativa depende de los escenarios operativos futuros. Algunos de los parámetros que definen estos escenarios se presentan a continuación:

condiciones hidrológicas

demanda

precios de combustible

costos de racionamiento

entrada de nuevos proyectos

disponibilidad de equipos de generación y transmisión

tarifas internas y de intercambio

El pronóstico de estos parámetros es muy complejo, y sujeto a una gran *incertidumbre*. Esta incertidumbre se representa a través de dos formas básicas:

*explícita* - la distribución de probabilidad de los valores del parámetro se representa directamente en el cálculo de la política operativa

*implícita* - el efecto de la incertidumbre del parámetro se representa a través de análisis de sensibilidad o utilización de valores promedios

El modelo SDDP representa de forma explícita la incertidumbre asociada a la hidrología. Las demás incertidumbres se representan de forma implícita.

1.3 Planteamiento del Problema

1.3.1 Sistemas Puramente Térmicos

En sistemas de generación compuestos solamente de unidades termoeléctricas, el costo de cada planta depende básicamente del costo de combustible. Por lo tanto, el problema operativo es determinar la combinación de plantas que minimice el costo total de combustible (carbón, hidrocarburos, nucleares etc.) necesario para suministrar la demanda.

En su versión más simple, este problema se resuelve colocando las plantas en orden creciente del costo de producir un MWh adicional (el costo incremental) y ajustando la operación a las fluctuaciones de la demanda. Aunque existan factores adicionales que tornan este problema más complejo (pérdidas de energía, limitaciones en las líneas de transmisión, costos de arranque, límites en la tasa de variación de la producción energética etc.), el problema de operación termoeléctrico tiene características básicas, resumidas a continuación:

*a*. es *desacoplado* en el tiempo, es decir, una decisión operativa hoy no tiene efecto en el costo operativo de la próxima semana

*b*. las unidades tienen un *costo directo* de operación, es decir, el costo operativo de una unidad no depende del nivel de generación de otras unidades; además, la operación de una unidad no afecta la capacidad de generación o disponibilidad de otra unidad;

*c*. la *confiabilidad* del suministro de energía depende solamente de la *capacidad total* de generación disponible y no de la estrategia operativa de las unidades del sistema.

1.3.2 Sistemas Hidrotérmicos

A diferencia de los sistemas puramente termoeléctricos, sistemas con un porcentaje substancial de generación hidroeléctrica utilizan la energía almacenada "gratis" en los embalses del sistema para suministrar la demanda, evitando así gastos de combustible con las unidades termoeléctricas.

Sin embargo, la disponibilidad de energía hidroeléctrica es *limitada* por la capacidad de almacenamiento en los embalses. Esto introduje una *relación* entre una decisión operativa en una determinada etapa y las *consecuencias futuras* de esta decisión. En otras palabras, si las provisiones de energía hidroeléctrica se utilizan hoy, y en el futuro ocurre una sequía, puede ser necesario utilizar generación termoeléctrica de costo elevado en el futuro, o inclusive interrumpir el suministro de energía. Por otro lado, si se conservan los niveles de los embalses a través del uso más intenso de generación termoeléctrica, y se registran caudales elevados en el futuro, podrá haber vertimiento en el sistema, lo que representa un desperdicio de energía y, en consecuencia, un aumento en el costo operativo. Esta situación se ilustra en la Fig. 1.



Figura 1 - Proceso de Decisión para Sistemas Hidrotérmicos

Por lo tanto, el manejo de estos recursos es un problema *dinámico*, cuya solución óptima es un *equilibrio* entre el beneficio presente del uso del agua y el beneficio futuro de su almacenamiento, medido en términos de la economía esperada de los combustibles de las unidades térmicas.

A este problema dinámico se agrega el problema de la irregularidad de los caudales afluentes a los embalses, que varían estacionalmente, de año para año, y regionalmente. Además, los pronósticos de las afluencias futuras son en general poco precisos. Esta incertidumbre con respecto a los caudales hace de la planificación de la operación de sistemas hidrotérmicos un problema esencialmente *estocástico*.

Finalmente, los objetivos de economía operativa y confiabilidad de suministro son *antagónicos*. Por ejemplo, la máxima utilización de la energía hidroeléctrica disponible a cada etapa es la política más económica, pues minimiza los costos de combustible. Sin embargo, esta política es la menos confiable, pues resulta en mayores riesgos de déficits futuros. A su vez, la máxima confiabilidad de suministro se obtiene conservando los embalses lo más llenos posible. Sin embargo, esto significa utilizar más generación termoeléctrica y, por lo tanto, aumentar los costos operativos.

El equilibrio entre costos operativos y confiabilidad de suministro se obtiene a través del *costo del déficit,* que representa el impacto económico asociado a la interrupción del suministro. La determinación del costo del déficit es un problema muy complejo, pero fundamental para la determinación de la política operativa más adecuada para el sistema. Si el costo del déficit es muy bajo, esto resulta en una utilización excesiva de los embalses, y por lo tanto en mayores riesgos de racionamiento en el futuro. Si el costo de déficit es muy alto, esto resulta en una utilización excesiva de los recursos termoeléctricos del sistema y, por lo tanto, en costos operativos elevados.

1.3.3 Operación de Sistemas Interconectados

La existencia de interconexiones con empresas o países vecinos permite una reducción de los costos operativos a través de la compra y venta de energía, y un aumento de la confiabilidad de suministro a través de la repartición de las reservas. En términos metodológicos, el problema de planificación operativa es determinar el nivel óptimo del intercambio, y los precios de compra o venta. En el caso de intercambios con sistemas que no están directamente interconectados, existe también el problema del peaje, esto es, como compensar los sistemas intermediarios por la utilización de sus recursos de transmisión.

En el caso de sistemas puramente térmicos, los costos de combustible proporcionan un mecanismo natural de *coordinación* para la compra y venta de energía entre las empresas. Si el costo operativo de la térmica más cara operando en el sistema A (la térmica marginal) es US$ 45/MWh y el costo correspondiente en el sistema B es US$ 40/MWh, es intuitivo que la operación más económica para el sistema A es comprar energía de B. Existen diversas alternativas para establecer los precios de este intercambio, como por ejemplo el "split saving" (promedio de los costos marginales de los sistemas - US$ 42.5/MWh, en este caso), o el costo marginal (un precio lo más cerca posible del costo de A).

Se observa que los intercambios de energía entre los sistemas térmicos resultan en la optimización *global* de los costos operativos del sistema interconectado. En otras palabras, los resultados que se obtienen con empresas independientes haciendo intercambios en base los costos de las térmicas marginales son los mismos que se obtendrían si las empresas fueran operadas conjuntamente, como una única empresa. También es importante observar que la coordinación entre las empresas se hace únicamente a través de *precios*, esto es, la empresa B no tiene informaciones sobre el sistema A (tipos de equipos, demanda etc.) o viceversa. Esto facilita los contratos de intercambio, una vez que no se necesita compartir informaciones comerciales.

En el caso de sistemas hidrotérmicos, es necesario determinar inicialmente el *valor* de la generación hidroeléctrica, que es el valor de la generación térmica que se podría substituir hoy o en el futuro. Este valor se calcula como una etapa del proceso de determinación de la política óptima.

Con este concepto, se puede representar una hidroeléctrica como una "térmica" cuyo "costo marginal operativo" es el valor del agua. Sin embargo, es importante observar que este valor *no se mide de manera aislada* en cada planta, pues depende de la operación *conjunta* del sistema. En otras palabras, si la política óptima hidrotérmica de cada empresa se calcula de manera aislada, los intercambios de energía posteriores, inclusive basados en los valores del agua de cada empresa, *no resultan* en la operación más económica posible.

En resumen, para obtener las ganancias operativas máximas de un sistema hidrotérmico interconectado, es necesario operar el sistema como una única empresa. Este es caso del sistema Colombiano, que se opera de manera coordinada.

2. ESTRUCTURA DEL MODELO SDDP

El modelo SDDP se compone de dos módulos principales:

1. *Módulo de Planificación Operativa* - Determina la política operativa más económica para los embalses, teniendo en cuenta las incertidumbres en las afluencias futuras y las restricciones en la red de transmisión; simula la operación del sistema a lo largo del período de planificación, para distintos escenarios de secuencias hidrológicas; calcula índices de desempeño tales como el promedio de los costos operativos, los costos marginales por barra y por bloque de carga, y los intercambios óptimos entre empresas; determina la operación óptima de corto plazo

2. *Módulo Hidrológico* - Determina los parámetros del modelo estocástico de caudales

La Figura 2 presenta el flujo de ejecución de los módulos, los principales datos de entrada, y los enlaces entre los módulos de cálculo de política operativa y simulación.



Figura 2 - Flujo de Ejecución de la Planificación Operativa

2.2 Flujo de Datos

Los datos de entrada para el módulo de la política operativa incluyen:

*a.* datos del sistema:

características del sistema hidroeléctrico (topología de los embalses, coeficientes de producción, límites de almacenamiento, límites de turbinamiento etc.)

características de las centrales térmicas (potencia instalada, factores de disponibilidad, costos operativos etc.)

programa de mantenimiento de los equipos

características del sistema de transmisión (topología de la red, susceptancia y límites de flujo en los circuitos)

*b.* demanda para cada etapa, cada bloque y cada barra de carga

*c.* parámetros del modelo estocástico de caudales

Los datos de entrada para el módulo hidrológico incluyen:

topología de los embalses

datos históricos de los caudales

3. MODELAJE DE LOS COMPONENTES DEL SISTEMA

En esta Sección se presentan los parámetros básicos de los componentes del sistema generación/transmisión. Estos parámetros en general varían por etapa, lo que permite representar cambios en el sistema o en la situación operativa (por ejemplo, la restauración de plantas térmicas afecta su tasa de salida forzada).

3.1 Plantas Hidroeléctricas

Los parámetros básicos de las plantas hidroeléctricas son:

número de la estación hidrológica

número de la planta aguas abajo para vertimiento

número de la planta aguas abajo para turbinamiento

número de la planta aguas abajo para filtración

número de generadores

capacidad instalada

coeficiente de producción promedio

caudal defluente máximo

caudal defluente mínimo

volumen almacenado mínimo

volumen almacenado máximo

tasa de salida forzada

tasa de salida programada

Hay también cinco tablas de datos:

coeficiente de producción × volumen

filtración × volumen

area × volumen

cota × volumen

coeficientes de evaporación mensuales

En la actividad de cálculo de la política operativa, se consideran coeficientes promedio de estas tablas. Esta simplificación es necesaria para garantizar la convexidad del algoritmo de programación dinámica dual (ver Apéndice A). En la actividad de simulación, se consideran los valores de las tablas.

3.2 Plantas Termoeléctricas

Los parámetros básicos de las plantas termoeléctricas se presentan a continuación:

número de unidades

capacidad instalada

generación máxima

generación mínima

tasa de salida forzada

tasa de salida programada

llave para planta de base ("must run")

El costo operativo se representa e dos maneras: a través de una tabla de costos operativos ($/MWh) o a través de una tabla de consumo específico de combustible.

3.3 Interrupción del Suministro

El déficit de suministro de energía se representa como una unidad termoeléctrica con costos operativos lineales por partes (máximo de tres segmentos lineales).

3.4 Red de Transmisión

El sistema de transmisión se representa por um modelo de flujo de potencia lineal. Los datos se dividen en *datos de barras* y *datos de circuitos*:

Los datos de barra son:

número de la barra

tipo de la barra: generación, carga o "slack"

nombre de la barra

tipo de la planta asociada: hidro, térmica o ninguna

número de la planta asociada

factor de participación de la demanda de la barra en la demanda total

demanda industrial

Los datos de circuitos son:

número de la barra origen ("de")

número de la barra destino ("para")

resistencia del circuito

reactancia del circuito

límite de flujo

3.5 Demandas

Hay dos tipos de datos de demandas:

mediano/largo plazo

corto plazo

La demanda de mediano/largo plazo se representa como bloques {potencia; duración} a lo largo de la etapa. Se representan hasta tres bloques de demanda por etapa. Se observa que estos bloques son "cronológicos", y no de tipo "curva de duración de carga". De esta forma, se representa la diversidad espacial de las demandas en sistemas vecinos. La demanda total se divide en demanda industrial y demanda proporcional. La demanda industrial se considera constante a lo largo de los bloques. La demanda proporcional varia a lo largo de los bloques.

Conocida la demanda total del sistema para un determinado bloque, la demanda de cada barra en el mismo bloque se calcula como:

*D*(*i*) = (*D* - *DI*) × *FP*(i) + *DI*(*i*)

donde:

*D*(*i*) demanda en la barra *i*

*D* demanda total del sistema

*DI* demanda industrial total del sistema

*FP*(*i*) factor de participación de la demanda de la barra *i* en la demanda total

La demanda para estudios de corto plazo se representa como un conjunto de bloques {potencia, duración} con hasta 21 bloques.

3.6 Caudales

Los caudales se representan como volúmenes naturales afluentes a cada planta hidroeléctrica en cada etapa. Los caudales se representan de quatro maneras:

1. *corto plazo* - esta opción solo se aplica a estudios de decisión operativa de corto plazo. El programa lee los caudales afluentes para cada bloque de la primera etapa del estudio (semana o mes).

2. *modelo estocástico de caudales* - ver Apéndice B

3. *sorteo del histórico* - el programa sortea los vectores de caudales de los registros históricos. Corresponde a un modelo estocástico de caudales con correlación serial nula. Sin embargo, se observa que este sorteo preserva la correlación espacial entre los caudales de distintas plantas

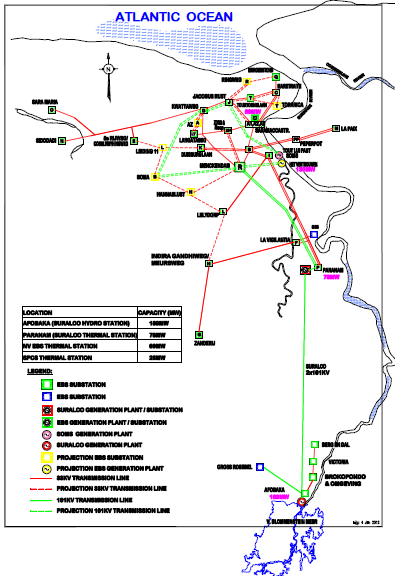
4. *forward/backward* - el programa lee las secuencias de caudales generados por un modelo estocástico externo

4. Algoritmo de Solución del Problema

En teoría, se podría resolver el problema (1) por un algoritmo de programación dinámica estocástica (PDE). Sin embargo, el esfuerzo computacional del algoritmo PDE tradicional crece exponencialmente con el número de variables de estado del problema, y resultaría excesivo en el caso del sistema Colombiano. Debido a esto, se propone utiliza la técnica de programación dinámica estocástica dual (SDDP). Esta técnica, desarrollada por PSRI, permite obtener los mismos resultados de la PDE tradicional, sin necesidad de discretización de las variables de estado.

**ANNEX 4**

**EPAR SYSTEM**



### ANNEX 5

**INVESTMENT, FUEL AND O&M COSTS**

This annex contains the detailed investment , fuel and O&M obtained for the two scenarios evaluated

### A. Investment costs

### a) Base scenario A

Next table summarizes the investment costs required during 2012-2025 in new generation plants under the Base Scenario A, representing USD 403.2 million that would be required for the installation of 366.5 MW, not including the investment cost of new hydroelectric power plant of 200 MW contracted through a PPA in the long term.

**BASE SCENARIO A - NEW POWER PLANTS: INVESTMENT COSTS (USDM)**



The investment cost in the required development of the transmission system is detailed in next table. It represents USDM 553.5 during 2012 – 2013 being significant and higher than the investment in new power plants.

**BASE SCENARIO A - INVESTMENTS IN NEW TRANSMISSION SYSTEMS (USDM)**



### b) Base scenario B

Next table summarizes the investment costs required during 2012-2025 in new generation plants under Base Scenario B. A total investment of USD 314.8 millions would be required for the installation of 366.5 MW, not including the investment cost of a new hydroelectric power plant of 200 MW contracted through a PPA in the long term. The main reduction of investment in generation costs in scenario B with respect to scenario A are related to the 85 MW new power plant in Moengo required to supply the Newmont gold mine, which under scenario A is not considered.

**BASE SCENARIO B - NEW POWER PLANTS: INVESTMENT COSTS (USDM)**



Total investments in transmission projects are also significantly lower in this scenario, representing USD 349.4 millions as presented in the next table.

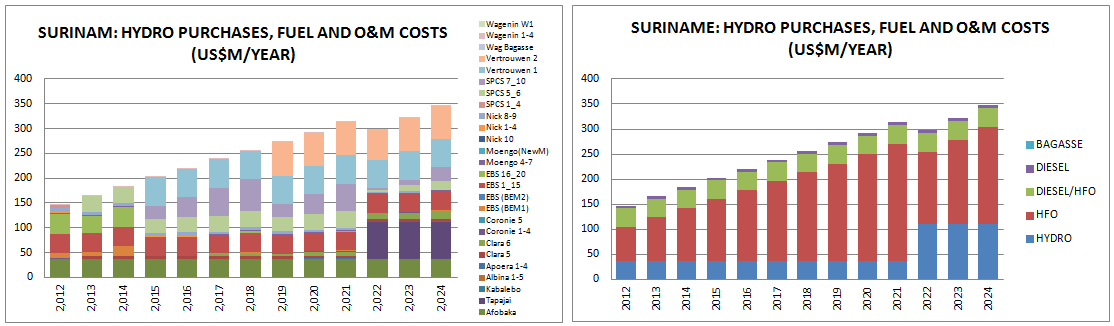
**BASE SCENARIO B - INVESTMENTS IN NEW TRANSMISSION SYSTEMS (USDM)**



### B. Fuel and variable O&M costs

Next graphs summarizes the annual forecasts of fuel and variable O&M costs related to the electricity supply in Suriname during 2012 -2025 under the two scenarios evaluated, obtained from the SDDP model simulations.

**BASE SCENARIO A – FUEL AND VARIABLE O&M COSTS**



**BASE SCENARIO B – FUEL AND VARIABLE O&M COSTS**



1. EBS’s current revenue only covers around 1/3 of its total operation and capital costs. [↑](#footnote-ref-1)
2. 1,197 GWh to EPAR and Districts and 128.6 GWh to Rosebel Gold Mines, see: Energiebedrijven Suriname Geconsolideerde jaarrekening 2012 [↑](#footnote-ref-2)
3. This assumption will imply that future electricity consumption per capita in Suriname will remain similar to its current value of around 2.230 kWh per capita/year. However, in case of a significant tariff readjustment to levels similar to the “cost effective tariff” (implying increases of around 130%), this consumption may be reduced significantly (for example other similar economies with higher electricity tariffs have lower per capita electricity consumption, as Honduras, 669 kWh per capita/year, Guatemala 559 kWh per capita/year, Bolivia 603 kWh per capita/year, etc.) [↑](#footnote-ref-3)
4. Price elasticity of electricity demand is a measure used in economics to show the responsiveness, or [elasticity](http://en.wikipedia.org/wiki/Elasticity_(economics)), of the quantity demanded of electricity to a change in its price. More precisely, it gives the percentage change in quantity demanded in response to a one percent change in price (holding constant all the other determinants of demand, such as income). Another indicator is Income elasticity of demand which relates percentage change of demand related to percent income variation. Both indicators permit the modeling of the behavior of the consumers to price and income variations permitting the estimation of the economic value of the consumed electricity. This situation has been empirically and theoretical supported in several Latin American countries. Suriname does not count with specific studies at this respect, for this reason in this study it was applied the experience in other Latin American countries. In Chile, recent studies indicate that the price elasticity of residential demand is -0.27 for one year and -0.39 for longer terms. Westley estimated it in -0.5 for Paraguay (1984) and in -0.45 for Costa Rica (1989) and Berndt & Samaniego in -0.47 for México (1984). In summary, available studies indicate that long term price elasticity of residential demand is in the order of -0.4 to -0.5. Based on such experiences, for the study it was adopted -0.6 as a conservative average price elasticity of electricity demand for residential sector in Suriname. [↑](#footnote-ref-4)