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Hydrothermal System Operation and Transmission Planning Considering Large Wind Farm Connection

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***Abstract*—This paper presents a methodology for incorporating the wind hourly behavior into operation simulation and transmission planning within a hydrothermal system framework. A wind power model to obtain wind speed time-series for the whole planning horizon is applied based on historical data. A simulation program based on SDDP (Stochastic Dual Dynamic Programming) for the optimum operation of a generation-transmission system is used for incorporating the wind energy features and it allowed to carry out the simulations. This research was applied to an existing hydrothermal system; chiefly for evaluating the dispatch of a large wind farm and its impact on both system operation and transmission planning.**

***Index Terms*--Interconnected power systems, Power system economics, Power transmission economics, Power transmission planning, Wind energy**

I. Introduction

THE transmission system plays a fundamental role in the electrical system, acting as the link between generation and demand, providing security of supply and allowing competition in the electricity sector. It also allows for the interconnection of different generation technologies into the system, where large wind farms connections are becoming more frequent.

From the electricity market point of view, the transmission system is seen as a constraint because it has a limited capacity, which affects the energy transfer between nodes. A weak transmission grid with a high degree of congestion results in higher operating costs due to the need to dispatch more expensive generators to supply the demand. Otherwise, the cost of operation will be lower but will require a higher level of investment [1]. Therefore, from this tradeoff between the operation cost of the system (short term) and the transmission investment cost (long term) it is possible to determine the optimal expansion of the network. This requires the simulation of the system operation on long term horizons (e.g. 10 to 15 years) and evaluating the performance of different investment alternatives based on the system operation cost.

Furthermore, in the context of a system with a strong hydro-generation component, the simulation of the operation over long term periods becomes a very complex task because it must deal with the hydrological uncertainty and time coupling decisions produced by the presence of reservoirs. To solve this problem, different simulation models have been developed that allow studying the operation of hydrothermal systems [2]-[6]. However, the increasingly penetration of wind power around the world makes necessary to incorporate these sources in the planning and operation of the electrical systems [7], adding an extra difficulty to the problem mentioned above.

Wind power is characterized as a highly variable resource on hourly basis. Moreover, the large number of variables that the simulation models must handle and the long term period required for the transmission planning studies makes very difficult to represent the wind hourly variations. That is why, until now, this hourly variations had not been considered in those models for long-term simulation. Presently, it is very necessary to incorporate wind farms in the generation and transmission planning activities, because the great variability of wind generation is a decisive factor in the decision making process. Therefore, a proper treatment is required.

The main purpose of this work is to develop a methodology that represents the wind hourly variations in long-term transmission planning studies (e.g. 10 years) within the framework of a hydrothermal system. This way, wind energy will be explicitly considered in the simulation of the operation and transmission planning.

This paper is organized as follows: Section 2 elaborates on the transmission business and how to tackle the transmission planning problem. In section 3 a wind modeling is applied for simulating hourly wind speed in the whole time horizons (e.g. 10 to 15 years). The wind resource integration into simulations models is explained in section 4. Finally, the results of the case studies and conclusions are shown in sections 5 and 6 respectively.

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II. THEORETICAL FRAMEWORK

A. The Power Transmission Business

Thanks to past decentralization drives, transmission is no longer rated as a mere link between generation and demand to the point of becoming, nowadays, a key element in the power sector competitiveness.

The noteworthy features of the transmission business are:

- **A link between generation and consumption**: transmission takes the energy from the resource location towards the load centers.
- **It delivers economies of scope:** the interconnection of different generation technologies reduces the energy production costs.
- **It provides security of energy supply:** the connection of multiple generating units to the transmission network allows the consumers to enjoy a supply reliability status, chiefly by means of an impact reduction of power station failures.
- **It facilitates competition within the electric sector:** transmission allows for competition within the electricity sector by allowing for a sound interconnection of a number of generators onto the system.

However, from an overall market viewpoint the transmission system's limited capacity can be rated as a constraint influencing the free transport of energy onto the consumers. Thus, the transmission capacity becomes the key element for determining the best economic balance between an operational efficiency in the short term and the optimal network development in the long term [1].

A weak transmission network with a high congestion rate is tantamount to high operation costs caused by the need to resort to more expensive generators. That said, demand cannot be met by cheaper generation because the transmission restriction has become a bottleneck. This situation creates local market prices, thus making the system economically uncoupled. Conversely, if a network has a high transmission capacity, its operational costs will be lower, but calling for a high investment level. Hence, there is a trade-off between system operating costs and transmission investment [1].

B. Analytical Problem Formulation

With a view to addressing the transmission planning problem, it is imperative to undertake optimal system operational simulations aimed at evaluating the trade-off between operational costs and the power transmission investment requirements.

In hydro-intensive power grids such as the Chilean Interconnected System, the operation simulation shall model the transmission network and the hydroelectric and thermal power stations, e.g., it will be a multi-nodal and multi-reservoir simulation that must encompass also the hydrologic uncertainty factor.

The availability of limited amounts of hydro energy in the form of water kept in reservoirs, turns the optimal operational issue into a complex one, creating a coupling between the decisions of a specific stage and the decisions to be adopted in future ones.

Furthermore, in the absence of perfect hydrological inflow predictions, the problem is essentially stochastic. The existence of several interconnected reservoirs and the need for securing a good optimization level throughout multiple periods, illustrates the magnitude of the problem to be dealt with.

From the mathematical viewpoint, this problem can be formulated as a recursion of Stochastic Dynamic Programming (SDP) [9]:

$$\alpha_t(X_t) = \underset{A_t|X_t}{E}\left\{ \underset{U_t}{Min}\ \mathrm{C}_t(U_t) + \beta\alpha_{t+1}(X_{t+1}) \right\} \quad (1)$$

Subject to:

$$X_{t+1} = F_t(X_t, A_t, U_t) \quad (2)$$

$$R_{t+1}(X_{t+1}) \geq 0 \quad (3)$$

$$S_t(U_t) \geq 0 \quad (4)$$

For each t = T, T-1, …, 1; for each X_t

Where:

t: indexes the stages (T planning horizon)

X_t: states vector at the start of stage t

$\alpha_t(X_t)$: expected value of the operational cost as from state X_t

$\alpha_{t+1}(X_{t+1})$: future expected cost function

$A_t|X_t$: probability distribution of inflow vector A_t as conditioned by state X_t

E{ }: expected value

U_t: decision vector for stage t

$C_t(\ )$: immediate cost associated to decision U_t

β: discount factor

Equation (2) corresponds to the state transition equation, equation (3) represents the constraints on the state vector and equation (4) includes the decision vector constraints.

C. Simulation of the Optimal System Operation

Solving the operational problem stated above by means of the SDP calls for the enumeration of all the possible combinations of both initial storage and inflows. Thus, the computer simulation approach grows exponentially in line with the number of modeled reservoirs [9].

In a large power system with multiple reservoirs it becomes necessary to adopt a methodology which does not require any state enumeration undertaking, thus alleviating the computer simulation requirements of the SDP recursion. In this context, a new approach called Stochastic Dual Dynamic Programming (SDDP) [2], [9] comes up and has been used in the SDDP model [6] developed by PSR, Inc. in Brazil or with the Ose2000 [5], developed by KAS Engineering in Chile.

The SDDP scheme is based on the representation of the future cost function (FCF) as a piecewise linear function, without the need for an enumeration of all the states. As it can be appreciated in Fig. 1, the future costs' function is estimated with only a few points.

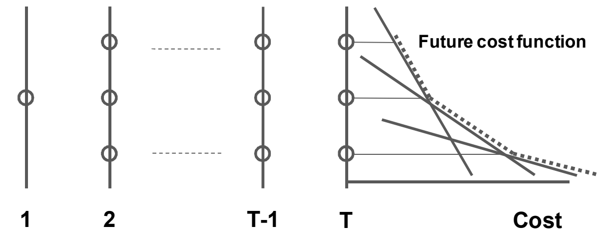

Fig. 1. FCF for stage T-l

Although these models are suitable for addressing the operational simulation issue their modeling does not encompass the wind energy option with an hourly representation for long term studies.

Therefore, an explicit methodology incorporating the wind hourly energy option within the simulation models is to be developed next. But fist, we need to calculate the wind hourly speed for the study horizon in order to perform the simulations.

III. Wind Resource Modeling

A. Probabilistic Modeling

For the whole study horizon (up to 10 years), it becomes necessary to have available hourly wind speed series capable of reproducing the typical seasonal wind patterns in a specific area. In order to do that, a probability wind simulation model developed in [8] is applied. This method considers the wind speed together with seasonal and random components (s(t) and R(t), respectively):

$$V(t) = s(t) + R(t) \qquad (5)$$

The simulation procedure involves four basic steps based on historical data information:

1. Identification of the seasonal variations;
2. Removing the seasonal factor and finding the deterministic component;
3. Normalizing the speed variance;
4. Modeling the residues.

The historical wind speeds were extracted from the public database issued by the Chilean National Energy Commission [11]. While on this we must state that this information was compiled from environmental monitoring stations therefore it was not collected with an exclusive focus on the wind resource, but it is adequate to implement and describe the methodology.

The seasonal variations are determined through the spectrum analysis stemming from the sampled data, which are merely hourly wind speed readings undertaken in period 2000 – 2003.

In Fig. 2 we can see that there is a strong component at a frequency of 0.0417 cycles per hour frequency; in other words there is a strong daily variation pattern. Afterwards, this component is removed, and the resulting spectrum is analogously analyzed.

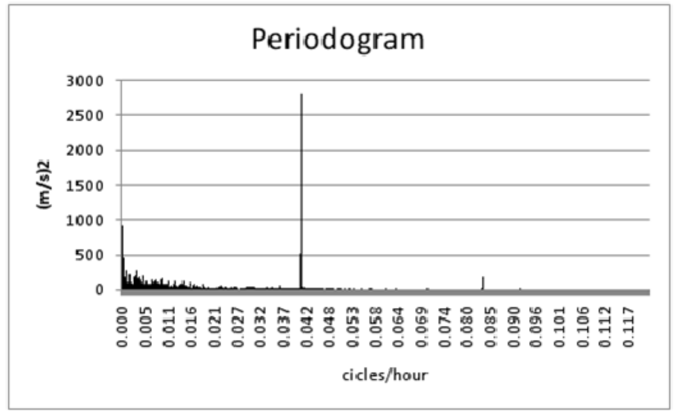

Fig. 2. Periodogram produced from the data samplings

Finally, the deterministic or seasonal part of our wind data is made up by the addition of the daily, half-yearly and annual variations as it is shown in Fig. 3.

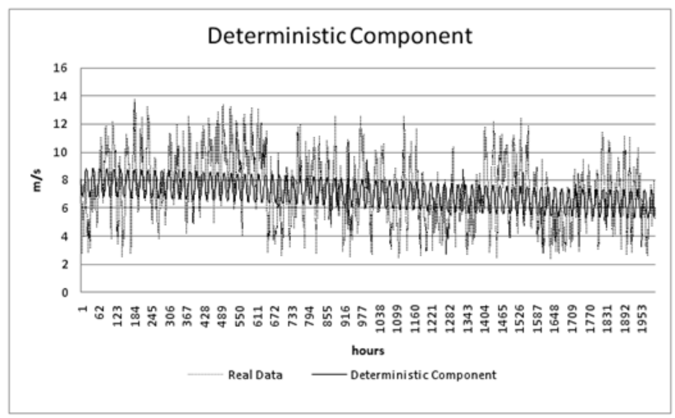

Fig. 3. Deterministic component of the wind data

By removing these seasonal components (referred to as s(t)) we get to the residues R(t).

However, these residues variance does not remain unchanged along the year; therefore, normalization of the monthly variance is applied as follows according to the model presented in [8]:

$$\tilde{R}(t,m) = R(t,m) / \sigma(t,m) \qquad (6)$$

Where R(t, m) and σ(t, m) represent the residue and the variance for the t hour of the m month, respectively.

Once the normalized residues data are available, they are adjusted with an ARMA (p, q) model using MATLAB, which minimizes the prediction quadratic error.

$$\tilde{R}(t,m) = \sum_{i=1}^{p} a_i R(t-i,m) + Z(t,m) + \sum_{i=1}^{q} b_i Z(t-i,m) \qquad (7)$$

Where Z(t, m) is the normally distributed error with a zero mean value and “ai” and “bi” are the ARMA (p, q) model parameters.

The variations of “p” and “q” were performed with a view to obtaining the best adjusted model, considering the minimum possible order of the ARMA model.

As the residues were normalized at the variance unit, the approximation error is represented by the error variance of the ARMA model [8].

TABLE I
NORMALIZED ERROR VARIANCE

p \ q	0	1	2	3
0	0.9485	0.4933	0.3716	0.3236
1	0.2594	0.2531	0.2531	0.2531
2	0.2534	0.2531	0.2531	0.2531
3	0.2531	0.2531	0.2532	0.2528

As it can be seen in Table I, the AR(1) model presents a prediction error which is very similar to the more complex models. If we apply an ARMA (3,3) model, the error drops to a mere 0.7% (0.2594 – 0.2528). For this reason an AR(1) model was adjusted and it resulted in an autoregressive coefficient for a = 0.8709.

Fig. 4 shows the adjustment resulting from our modeling, where the model comes close to the seasonal variations of the site.

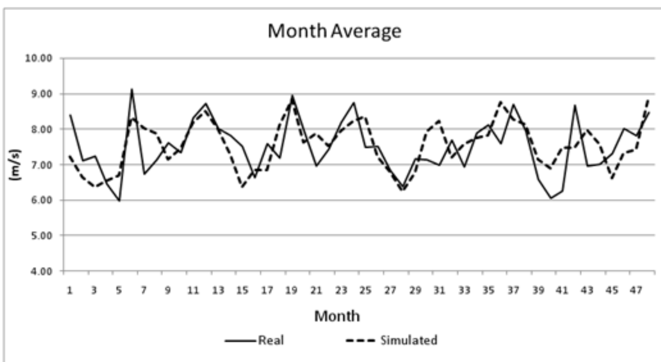

Fig. 4. Real and simulated wind speeds

B. Output Power

The output power of a wind generator is determined by the power curve which depends of the turbine's own features, expressed as a function of the wind speed. In this paper the technical features of a 2 MW generator turbine will be used (Vestas V80 – 2.0 MW).

The aggregation of wind generators was made in line with the modeling advocated in [8] that considers the same wind conditions throughout the wind farm.

IV. INCORPORATION OF WIND FARMS TO THE HYDROTHERMAL COORDINATION MODEL

When incorporating wind energy farms onto the transmission planning stage, it is essential to include the effects of hourly variations of wind generation. The simulation model Ose2000 [5] will be used in this work.

From the operational viewpoint, wind farms are similar to the run of river power stations, with both encompassing variable generating sources and thus being dependant on the availability of their respective primary energy source.

For this reason, the modeling of wind farms in Ose2000 will be made in line with run of river power stations. In other words, they will be considered as thermal units, with zero variable cost and a variable power output as a function of the wind flow availability.

However, the hydraulic influx presents a dynamic variation which is slower than the wind's one and therefore resulting adequate to consider a weekly or monthly treatment. This does not happen with wind that experiences significant hourly variations. Therefore, a more detailed load demand and generation modeling is developed in the Ose2000 program with a view to reproducing the wind hourly variations.

A. Demand Modeling

Frequently, the operation simulation model as far as long term studies and forecasts is concerned (around 10 years into the future) does consider demand in monthly terms using the load duration curve (LDC). This treatment converts the LDC into a number of average values or blocks as shown in Fig. 5.

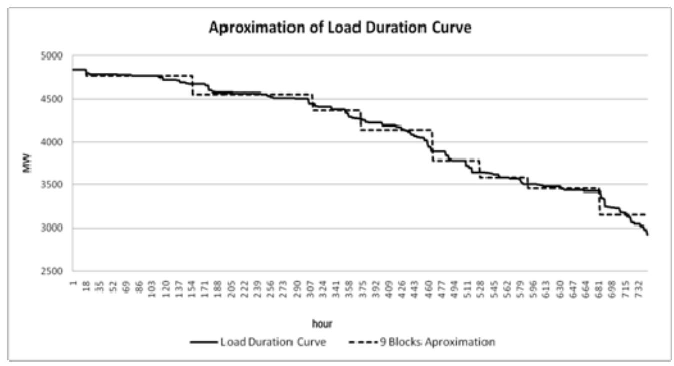

Fig. 5. Approximation of the monthly load duration curve

The demand curve values are ordered from top to lower in order to minimize the approximation error. Therefore, any other approximation to a demand curve which differs from LDC will result in a larger estimation error.

However, the main disadvantage of using the blocks approximation of the load duration curve is that it does not allow modeling the wind hourly speed variations. Whenever there is an ordering of the demand values from higher to lower rates, the hours' chronologic order is lost. For instance, hours 5 and 7 could be in the same block whereas hour 6 could well be in a completely different block.

Therefore, if we are representing the effects of wind speed hourly variations, it is necessary to work with the system's load curve where the blocks group together the hours in a chronologic format. In this way, it becomes imperative to develop a tool allowing for an estimated block build up for this new curve thus minimizing the quadratic error.

As a general rule, in the Ose2000 model the monthly load duration curve is represented between 2 and 5 blocks, thus obtaining fairly short processing times (from 1 to 2 hours in a PC with an Intel Core 2 Extreme QX6800 Processor) for long-term studies. It is possible to extend the number of blocks to more than 10, thus for this application we consider a maximum of 9 blocks for obtaining acceptable processing times (about 7 hours with the QX6800 processor).

The monthly load curve encompasses correlative hourly demands. This means that the data showing sequence starts with hours 1 to 24 of day 1, then hours 1 to 24 of day 2, and so on. With a view to identify the monthly demand performance in each hour, the load curve was ordered in line with the hours of the month, i.e., if the month has 31 days, we would get the curve showing first the set of 31 readings for hour number1, followed by a set of 31 readings for hour 2, and so on. Fig. 6 below shows both curves.

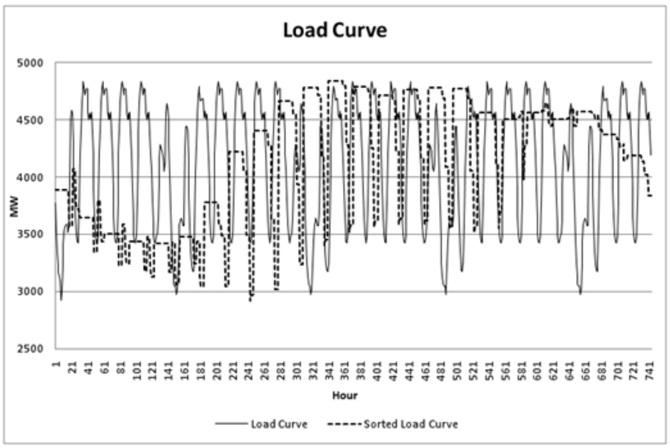

Fig. 6. Real load curve sorted by hour sets

It follows that an approximation by blocks of the load curve ordered by hour sets has been undertaken. With this data presentation approach we obtain correlative hours in each block, thus allowing us to reflect the wind variations in hourly formats by blocks. With a view to reduce the approximation error, this curve is grouped in similar demand days while also observing its chronological order.

B. Wind Generation Modeling

The variability of the wind resource, represented by the speed vectors obtained through the above methodology, will be incorporated to the Ose2000 model, through the blocks representation developed above.

Therefore, if the wind speed during the morning is low, the energy generated in the blocks for such morning hours will also be low and vice versa.

On the other hand, for the hydrological uncertainty modeling, the Ose2000 program uses the simulation of different scenarios. As specified above, wind farms are modeled bearing in mind their similarity to run of river power stations, so it is possible to use this structure when incorporating the wind uncertainty factor while defining different wind scenarios stemming from different wind simulations.

Based on the foregoing, it becomes feasible to address the transmission planning problem by taking into account the wind hourly variability.

V. Simulations and Results

A. Effects of the Wind Variability

When evaluating the wind variability effects on system operation and transmission planning, a wind farm was simulated with a constant generation output equivalent to its average and was compared with variable wind generation according to the methodology developed before. This situation was simulated in a two-bus system shown in Fig. 7.

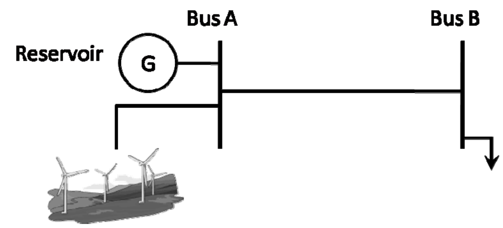

Fig. 7. Two-bus study system

For this scenario, a 200 MW wind farm was connected to the bus A together to 300 MW reservoir plant. The line has a capacity of 385 MW. When the wind farm with constant generation is connected there is no congestion in the line. However, the wind park with variable generation produces some congestion in the line A-B and lower energy marginal costs in the bus A. The line flows in both cases are shown in Fig. 8.

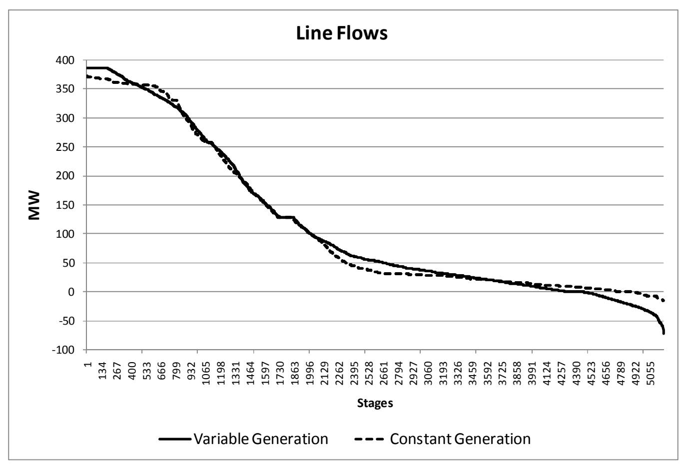

Fig. 8. Flow comparisons

If all the generated energy is sold on bus A at their respective marginal cost we will obtain the generator revenues. Comparing both constant and variable wind generation cases we obtain that the revenues difference is bigger than the expansion cost of build a second circuit between A and B.

Therefore, the adequate modeling of the wind hourly variations becomes a crucial factor when undergoing the investment evaluation stage.

B. Real case application

The methodology presented in this paper will be applied into a real case, the Chilean Central Interconnected System (better known for its Spanish acronym: SIC). The modeling of the system will be the one specified by the Chilean National Energy Commission [10], which entails 10 reservoirs, 25 run of river plants and 110 thermal power stations. The system is represented by 180 buses and 240 transmission sections. The simulation time horizon is 10 years as from April 2007 and the wind farm is connected in October 2009. Furthermore, 48 scenarios were considered - either hydrological or wind based - and 9 monthly demand blocks that resulted in 5,184 annual stages (=9*12*48).

1) Current Situation

The Fig. 9 shows a simplified diagram of the system. A 400 MW wind farm will be connected in Puerto Montt.

The wind farm connection will increase the lines flows because in this zone of the system the energy travels from Canutillar to Cautín.

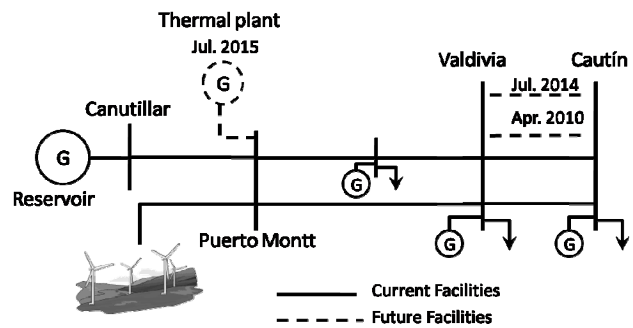

Fig. 9. Simplified diagram of the study zone

In Fig. 9 each of the new circuits (dashed lines) has a 166 MW of capacity and the new thermal plant is 250 MW

The critical section of this zone is the Valdivia – Cautín section. The congestion produced by the wind farm connection on this line is shown in Fig. 10. We can observe in the flat part of the curves the congestion for the year 2013 and 2015.

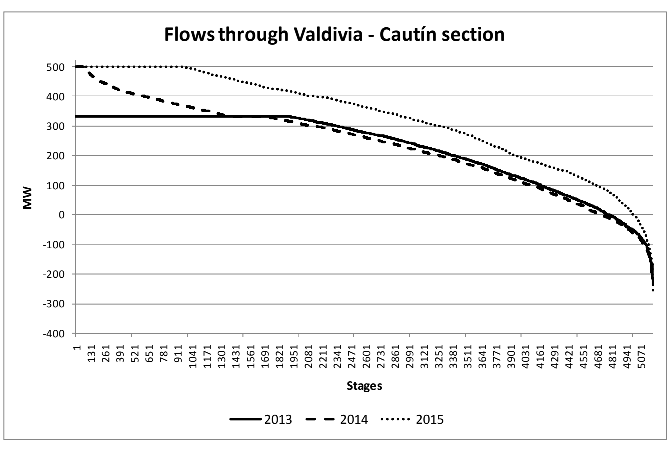

Fig. 10. Line flows with the wind farm connection.

2) Operational Impacts

In addition to the line saturation shown in Fig. 10, the wind farm connection produces operational effects. The transmission line saturation creates local market prices, thus making the system economically uncoupled. Furthermore, the extra energy offer will have an important impact reducing energy nodal costs for the whole planning horizon, as it is shown in Fig. 11.

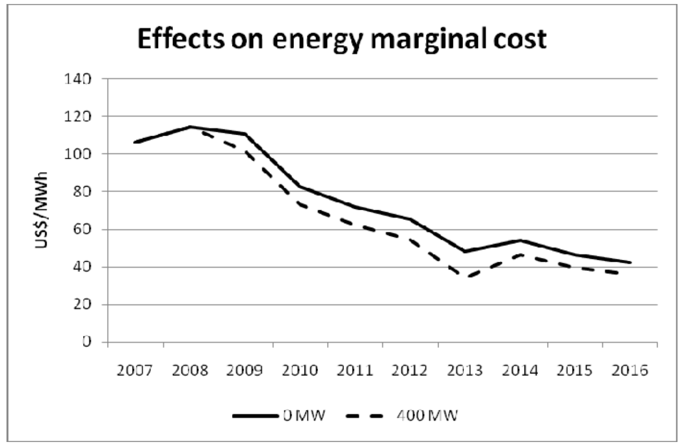

Fig. 11. Energy prices in Canutillar bus.

Another operational effect is produced on reservoirs. Since the line has no extra capacity the energy will be accumulated in the reservoir raising his water level as is shown in Fig. 12.

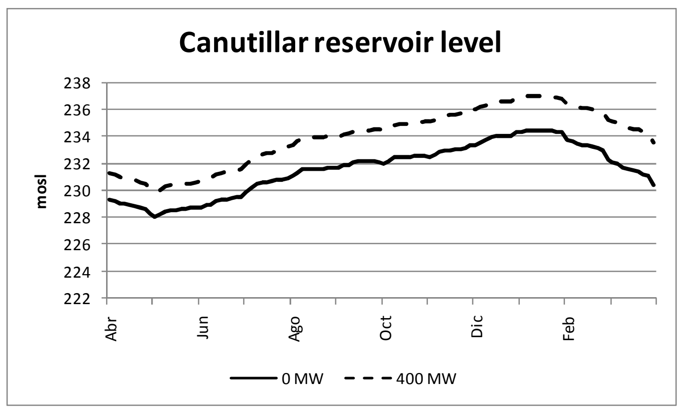

Fig. 12. Canutillar resorvoir levels for 2010

In other words, all the wind energy surpluses that can not be transmitted through the line will be stored in the reservoir.

The lower energy prices and lower generation of reservoir plant produces an important decrease on Canutillar plant revenues, about 18% according Ose2000 results.

3) Effects on the transmission expansion plan

As we can see in Fig. 10, the wind farm connection produces an important congestion in the Valdivia – Cautín section. For this reason it is necessary to increase the transmission capacity of the new circuits from 160 MW to 300 MW. The annual additional investment for this upgrade is US$ 1.3 millions approx. and the system savings for this upgrade was US$ 1.4 millions according the Ose2000 simulations. Therefore, the upgrade is necessary from the economic viewpoint.

The power flows in this new situation are shown in Fig. 13.

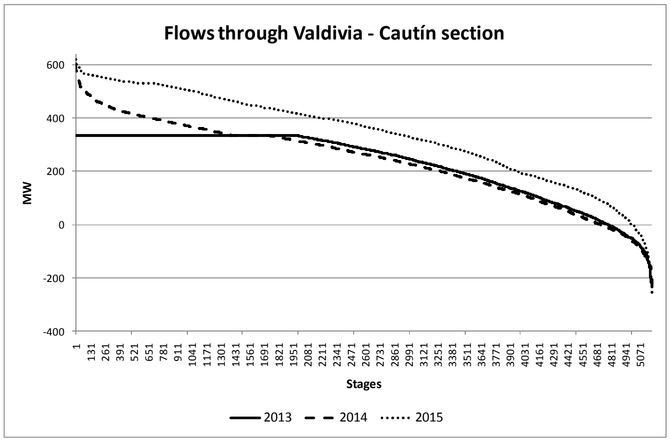

Fig. 13. Power flows through Valdivia – Cautín section with the new upgrades

In Fig. 13 we can see that the problem still exists for the year 2013. For this reason, the connection of the fourth circuit between Valdivia and Cautín in the year 2013 is evaluated. This mean an annual additional investment of US$ 1 million approx. while the system saving are US$ 1.35 millions according to Ose2000 results.

Summarizing, the effects of connecting a 400 MW wind farm will change the original transmission expansion plan. Particularly, the capacity of the new circuits must be increased from 166 MW to 300 MW and the fourth circuit is needed in operation from 2013 instead of 2014.

VI. Conclusions

Wind power farms are now starting to play an important role in the planning and operation of power systems everywhere in the world.

This paper presented a methodology to evaluate the impact of these variable energy sources on both the operation of the power system and the transmission planning activities.

In order to incorporate wind energy in a simulation program (Ose2000) based on the Stochastic Dual Dynamic Programming methodology, whose main goal is the optimal operation of a hydrothermal system such as the Chilean interconnected power system, we have undertaken a demand modeling able of represent the hourly wind variations is undertaken. This simulation is combined with a probabilistic model capable of modeling and representing the stochastic and seasonal wind variations.

The analysis included the prospects of connecting a number of wind farms and their likely impact on the transmission network, energy prices and on the reservoirs' water levels alike. This document also encompassed the suitable representation of wind variability impact, resulting in a crucial factor when it comes to the decision-making process during transmission planning.

This methodology was applied into real hydrothermal system. The operational effects produces on energy nodal prices and reservoirs was evaluated and the impact on the existent transmission expansion plan was determined for the south of the Chilean Central Interconnected System.

VII. Acknowledgment

The authors gratefully acknowledge to KAS Engineering for providing access to its Ose2000 software, and also to the Catholic University of Chile.

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IX. Biographies

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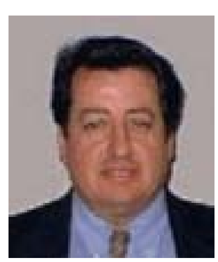

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