Assessment of the Introduction of Smart Metering in a Developing Country

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***Abstract*— A methodology to evaluate the installation of new electricity metering technologies in a developing country is formulated, taking into account the different consumption realities of these countries customers' and those of developed ones. A geostatistical procedure is performed using a georeferenced customer database, identifying a particular urban zone in which, under certain assumptions, smart metering deployment would maximize customers demand response in terms of peak demand reduction. A model is developed to determine installation costs, under a massive deployment scenario, concluding that given low local labor costs, the main cost driver is equipment cost.**

To determine customers' demand response impacts on the electricity market and prices, a model is developed based on an advanced hydrothermal dispatch model. System marginal costs, generation profits and societal welfare are studied. Societal benefits could overcome smart metering deployment costs when market participants are faced to prices based on a marginal cost scheme. Although smart metering would provide benefits to all society, customers originating these benefits would only perceive a small part of them.

***Index Terms*— Demand Response, Advanced Metering, Smart Meters, Kernel Smoothing, Geostatistical Analysis.**

I. Introduction

In many developing countries, electricity markets have been deeply reformed, aiming at introducing market principles to increase efficiency and benefit customers directly via lower energy prices [25]. These markets are facing new challenges mainly driven by a rapid increase in energy consumption and a not-so-fast system capacity expansion, with customers fearing energy curtailment. Regulation has become reactive, with periods of great legislative effort after mayor shortage crisis arises, introducing short-term solutions to a long-term problem: the inefficient use of energy resources.

Present metering technology, used for most users, limits the promotion of more efficient customer behavior. Deployment of advanced metering technology, also known as Smart Meters, vastly tested on other nations, would allow users to adapt their energy requirements accordingly to time varying price signals, providing system relief and important benefits to all society. There has been little interest in this subject is most developing countries, mainly because new technology costs are perceived as too expensive. It does not help that often, existing tariff schemes do not provide incentives to distribution utilities to encourage users to reduce their energy consumption.

This paper proposes a methodology to study the impact of introducing smart metering in a developing country, applying it to Chile's main distribution company, Chilectra.

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II. Smart Metering

A. Traditional Meters

The great majority of electric consumers in developing countries own or lease an electromechanical meter to allow the measurement and determination of their energy bill in a given period. The meter operation is based upon a disk that rotates due to the application of a magnetic field, caused by the flow of electric current, thus being able to meter the total energy consumed. For billing purposes, electricity consumption for a given period is calculated as the difference between the current and previous meter reading [7]. This type of meter is massively used, mainly associated to residential and small commercial customers. Reading of these meters is done manually and usually on a monthly basis.

B. Smart Meters

The arrival of solid state meters has meant a major breakthrough in terms of measurement technology, replacing the old system for electronic components. This has greatly improved the accuracy, reliability and size of these devices, which can also measure – without major additional costs – a greater number of variables, such as reactive power, power factor, harmonic currents and maximum power, among others. Additionally, progress in communication technologies has allowed these meters to optionally transmit data through various means, for example, PLC, RF, GSM/GPRS, etc. [10].

There is no universal definition for the term Smart Meter but it typically refers to a solid state meter with real-time communications enabled, capable of storing at least 15-min interval measurements, and additional features that are useful both for the utility and customers. These advanced meters, together with the entire communication network and data management supporting them, forms what is it called as AMI (Advanced Metering Infrastructure) [4, 15].

Some benefits offered by these systems are: remote meter reading, remote disconnection/reconnection of customers, remote modification of contractual parameters, detection of energy theft and meter adulteration, network optimization to reduced technical losses, enabling customer demand response, and, finally, allowing the incorporation of micro-generation. Ref. [10] details different means and architectures available to provide the communication link between customers and their utilities. It concludes that the most appropriate technical-economical route on densely populated areas is through PLC transmission.

C. Costs

The review of international studies, including business case analysis of various countries that have studied or implemented a massive deployment of smart meters, provides different cost figures. They depend on the scale of the installation, the technology used and the requirements of each market. Table 1 shows typical values [14, 20, 21, 32], representing around US$ 100 per meter point, for meter plus installation and communications costs.

TABLE 1
COST PER SMART METER

Place	US$/meter
Italy	102.93
Netherlands	151.47
Victoria	114.70
Ontario	100.00
SCEd	115.62
OFGem	107.42
SDG&E	94.30

III. Framework of Analysis

The trend in developed countries is to perform full-scale smart metering deployments on a geographic area. Even though the installation of millions of customers is very costly, it is socially profitable due to a massive consumer response to direct and indirect efficiency incentives. The situation is different in developing countries, where energy requirements of customers are dramatically lower (Fig 1), compared to those countries introducing advanced metering technologies. This could anticipate a lower demand response, and part of this investigation is to determine the user group whose response could be maximized in their energy consumption requirements. A method is proposed for identifying, within the universe of residential and small commercial consumers, a city area where installation would be more convenient using geostatistical analysis techniques

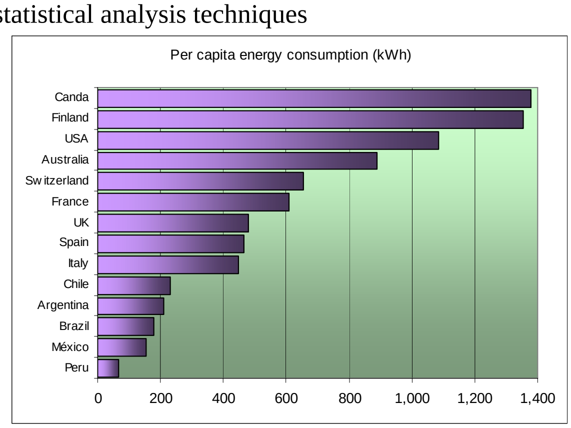

Fig. 1: Per capita energy consumption comparison.

A. Data Used

Customers' georeferenced monthly energy consumption data during 2007 was provided by Chilectra, the Santiago distribution company. Without more detailed information, certain assumptions were needed to identify potentially more demand responsive customers. It was assumed that a certain area is more convenient if:

- Customers' consumption levels inside it are at least one standard deviation above total average. These customers have a consumption level that would provide a greater opportunity for demand response, compared with a low consumption client, probably only supplying its basic energy needs.
- Monthly consumption variability within the year is above total urban population average in at least one standard deviation. High monthly variability would provide with a greater room for demand reductions.
- There is uniformity in the two above-mentioned characteristics in the area. This will take advantage of density economies, significantly reducing installation costs.

B. Spatial Autocorrelation

The use of spatial statistical analysis techniques allows a better understanding of the information contained on known coordinate points, especially the spatial relationship between these points' features; for example, if groups of items or customers with similar attributes are concentrated. In order to identify these concentrations or clusters, the application of autocorrelation functions [2, 17] is commonly used. Positive autocorrelation of an attribute within a set of points indicate that similar data is found together. Moran's and Getis-Ord indexes were calculated for the georeferenced database. Moran's Index is given by

$$I = \frac{\sum_i \sum_j w_{ij} \cdot (z_i - \overline{z}) \cdot (z_j - \overline{z})}{\frac{\sum_i (z_i - \overline{z})^2}{n} \cdot \sum_i \sum_j w_{ij}} \quad (1)$$

It basically corresponds to an index that relates pairs of points, summing equal sign and subtracting non equal sign pairs. Moran's index varies from -1, in case of negative autocorrelation, to +1 when complete positive autocorrelation is found. It measures the degree of similarity/dissimilarity between clients and their neighbors. Getis-Ord Index is given by

$$G^* = \frac{\sum_i \sum_j w_{ij} \cdot z_i \cdot z_j}{\sum_i \sum_j z_i \cdot z_j} \quad (2)$$

Getis-Ord index is capable of distinguishing if groupings are formed by elements with values above average (Hot Spots) or below average (Cold Spots). Therefore, the index is high if clustered elements are above average and low otherwise.

For both indices, theoretical expected values and standard deviations can be calculated for independent randomly distributed data and from them determine statistical significance level. These indices are calculated over the full geographic extent of analysis, i.e. are global indices. However, the same indices can be calculated, under certain variations, in a local form [2, 22], for sub zones within the study area, for example for every cell in a 500 x 500 m grid. The application of local indices is presented in Fig. 2 for monthly energy consumption and monthly variation of Chilectra urban customers.

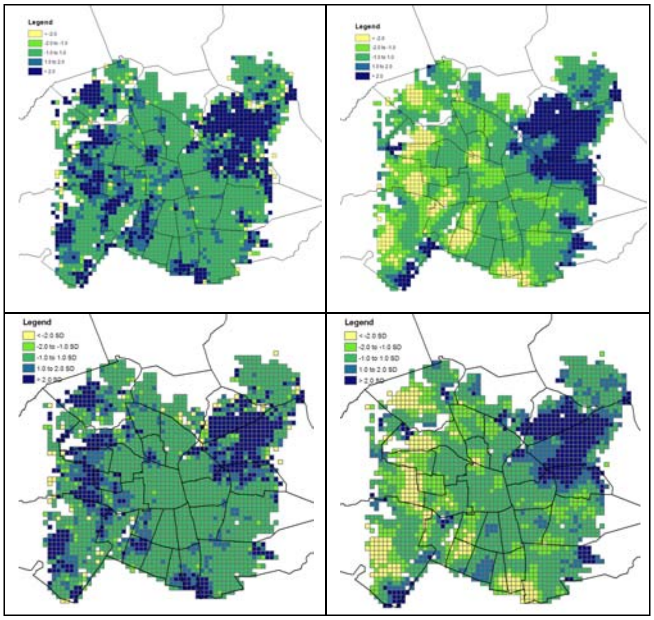

Fig. 2: Z values graphical representation for Moran's Index (1 column) and Gtis-Ord Index (2 column) for customers' monthly consumption (Row 1) and monthly variability (Row 2).

Fig. 2 suggests the existence of a direct relationship between monthly consumption and its monthly variability. Fig. 3 shows a first order polynomial fit between mentioned parameters. A clear correlation is observed between monthly consumption and its variability within the year, meaning that one can search for installation areas studying either of both parameters.

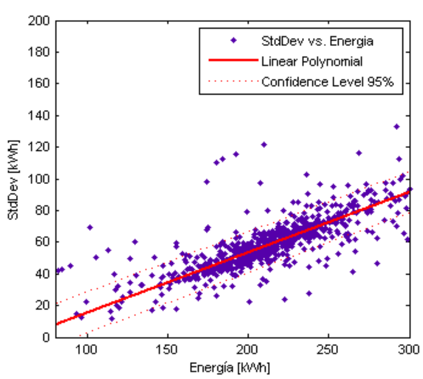

Fig. 3: Monthly energy consumption/variation correlation. (R^2=0.87)

C. *Kernel Smoothing*

Kernel density estimation was performed to every data cell in order to provide a graphically smooth surface. It is a statistical non parametrical method to estimate the probability density function of a random variable [9]. For the application required in this research, the idea is to estimate the mean value of a variable of interest as a function of its geographical position. Kernel smoothing has been applied for the geographical study of criminal data information [34], medical science [18] and marketing [12].

A Kernel is a function $K_h(X\text{-}X_o)$ that depends on positions of X y X_o, in such way that K is greater for smaller distances (X close to X_o) and vice versa (X far to X_o). K also depends on parameter h, known as the function's bandwidth. It determines how quickly K decreases with distance. Thereby, an approximation of the interest variable for the whole study area is given by the Nadaraya-Watson estimator as follows:

$$\widehat{Y}(X_0) = \frac{\sum_{i=1}^{N} K_h(X_i, X_0) \cdot Y(X_i)}{\sum_{i=1}^{N} K_h(X_i, X_0)} \qquad (3)$$

Typically, Kernel functions have Gaussian shape. One that is widely used in the literature is precisely a truncated quadratic approximation of the Gauss function, known as Epanechnikov function [9], defined as follows:

$$\frac{3}{4}(1-t^2) \qquad with \quad t = \frac{d}{h} < 1 \qquad t = 0 \;\; otherwise$$

Where d is the distance between X and X_o and h is the bandwidth. Kernel smoothing application results over monthly energy consumption are shown in Fig. 4.

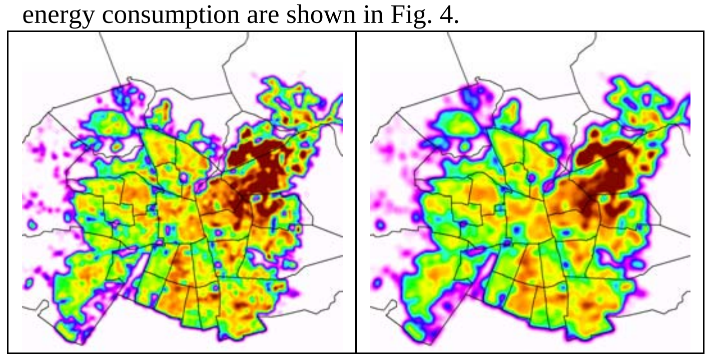

Fig. 4: Kernel smoothing applied to customers' monthly energy consumption for bandwidths of 500 m (left) and 750 m (right).

D. *Zone Delimitation*

The result of Kernel analysis is consistent with the calculation of autocorrelation indices previously carried out. Therefore, the definition of an installation zone follows, based on the support of geographical tools. One could easily proceed to delimitate the installation zone through hot spot borders at this stage. However, in order to give greater clarity to the target population and personnel in charge of installation labors, it is necessary to delimit the area in terms of the road network. To do so, installation zone limits are drawn through relevant avenues of the city (Fig. 5).

IV. Costs

The main cost variables that have been identified in international experience are the installation costs and costs associated with the investment [6, 10, 14, 23, 24, 26, 27]. For the purpose of this paper's evaluation, meter installation costs identified in regulated tariff processes of Chilectra are used [29-31]. Chile's distribution tariff regulation uses the concept of a model company, a theoretical company that is built on paper, which invests and operates the distribution system in an optimal way, under the local economic and physical restrictions [35].

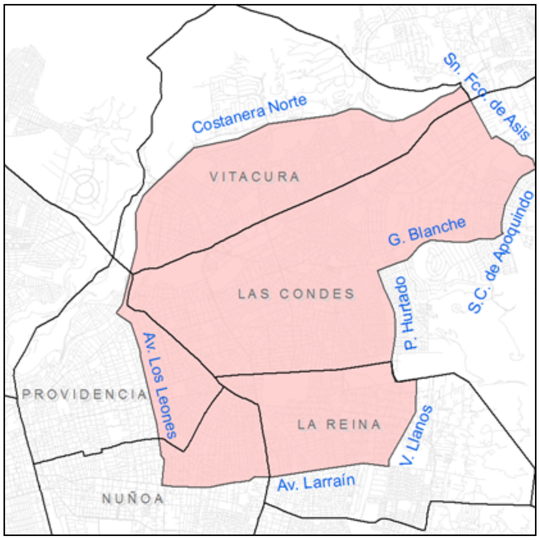

Fig. 5: Installation zone delimitation.

A. *Installation Costs*

Labor Data

• The labor time required to change a meter is 40 and 80 minutes for single and three phase meters, respectively [31].

• Installation crews are conformed by an officer and 2 assistants with a work vehicle brand Hyundai, model H100 Porter (gasoline) and work equipment with a an annual cost of approximately US$ 16.000. In addition, supervisory staff is in charge of overseeing 5 installation crews [29].

• A monthly target of 5,000 installations was assumed, considering 7 working hours a day and 20 working days per month, aiming to complete deployment in 3 years.

Transport Data

• Crews' working vehicle average speed is assumed to be 30 km/hr.

• A warehouse located at the distribution company's main office is considered, which constitutes the departure point of installation crews. Distance between warehouse and installation cells is assumed as the largest direct distance, i.e. sum of distances along X and Y axis.

Cost Model

The installation zone was divided by a 500 x 500 m grid. A procedure was applied to every cell in the grid, as illustrated in Fig. 6. Results obtained are shown in Fig. 7, which permits the comparison between meter replacement cost determined by this research and the reference one obtained from regulated tariff study determination [29]. It is concluded that when density economies are considered in the installation, a 40% cost discount can be obtained.

B. *Capital Costs*

Meter costs observed in international studies and experience were used, the same for maintenance costs and meter failure rate.

C. *Results*

Table 2 shows the consolidated results of the costs of implementing the new metering system. Total cost per metering point is approximately US$ 132, consistent with the international experience reviewed. Installation costs accounts for nearly 10% of the total cost per meter.

TABLE 2
COST RESULTS

	Total Cost (U$)	Cost per meter (US$)
Meters & Concentrators	17,333,693	91.27
Installation	2,852,873	15.02
IT Support	4,881,045	25.70
Total	25,067,611	131.99

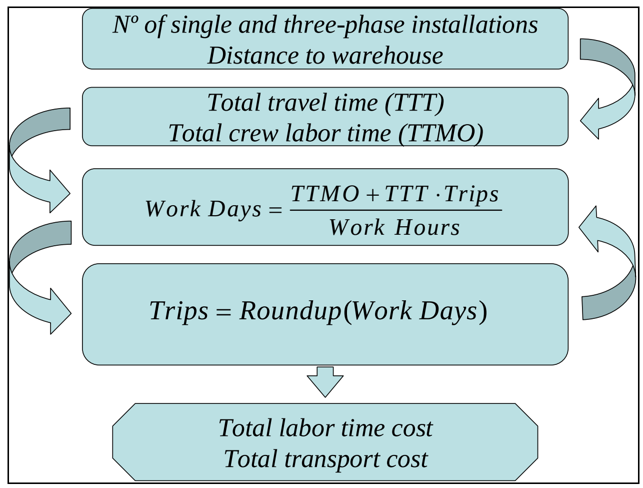

Fig. 6: Installation cost model.

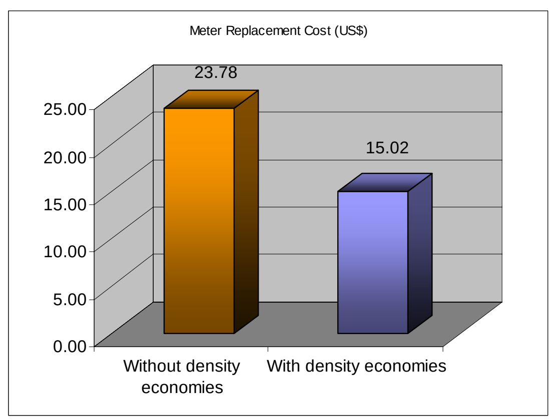

Fig. 7: Meter replacement costs comparison.

V. Assessment of Benefits

A. *Meter Reading, Billing and Customer Service*

The proposed smart metering system measures clients remotely through the electric grid via PLC communication technology, therefore there is no longer need to send reading personnel to customers' premises. Additionally, more accurate information is available, thus reducing measuring claims and providing a more reliable and expedite billing process. A 100% saving in meter lecture costs per each customer inside the installation zone was assumed, and a 75% reduction of customer service and billing costs. Thus, each smart meter installed would provide $2,222 and $2,832 savings per single-phase and three-phase customer, respectively.

B. Meter Losses

Traditional meter power losses will be avoided; values used are 1.092 W per single-phase and 3.422 W per three-phase meter. These power losses, due to their nature, are considered constant along time, thus a 100% load factor is assumed. Therefore, annual energy loss is calculated as the product between power loss and the hours in the year. For solid state meters, power losses are considered to be 0.5 and 1.5 W [5] for single-phase and three-phase, respectively.

C. Starting Watts Losses

Electromechanical meters have a particular drawback, based on their construction principles. In order to move the disc to start measuring consumption, the force applied to it by the magnetic field should overcome certain threshold in order to defeat its inertia. The power required to begin to move the disc is called Starting Watts and according to manufacturers typically is near to 25 W, while for solid-state meters is about 5 W [5]. Thus, all consumption below 25 W is not measured or billed b y traditional meters. It was found that on average, each customer annually consumes 5 kWh of energy that is not billed. Because this phenomenon typically occurs at times of low demand, it was not considered for power billing purposes.

D. Meter Maintenance

Electronic meters require no maintenance and calibration cycles like their electromechanical counterparts, the later requiring a yearly meter sampling, following rigorous inspection rules. Since the amount allocated to this activity is directly dependant on the number of customers, the value of this activity is reduced in proportion to the number of smart meters installed.

E. Non-Technical Losses

One of the major concerns that lead distribution utilities to adopt smart metering technologies are non-technical losses incurred in their networks [11, 33], which involve high costs. According to the Chilectra 2008 tariff study [30] these losses are assumed as 2% of energy sales at low voltage. A reduction of one third of the losses was assumed attributable to the installation zone.

F. Meter disconnection/reconnection

Smart metering technologies most important features are related with the capability to perform remote tasks. In particular, a very attractive functionality is the ability to disconnect and reconnect clients without the need to send a working crew to perform this task. Even though this cost is entirely paid by customers, it will be accounted to determine the levels of savings that could be seen. For purposes of assessing this contribution, design demand for this service was assumed as determined in [31] as the demand for it through the entire study horizon, in proportion to the meters installed. Cost of this service as in [29] is of $6,481 and $15,675 per single-phase and three-phase customer, respectively.

G. Meter reading verification

All human work is subject to error, and certainly reading meters is one of them. When such an error arises, the distribution utility must send personnel by customer's request to check the meter reading and study whether it is an error or not. It was supposed that the distribution company pays for this service, i.e. customer is always right. Again it was considered the design demand as the demand for this service for the entire study horizon, taken from [31] in proportion to the number of customers in the installation zone. Unit costs considered are $ 2,404 and $ 6981 for single and three phase customers, respectively [29].

H. Results

Table 3 shows the result of the benefits identified by meter.

TABLE 3
ANNUAL BENEFITS PER METER

Benefits	US$
Metering, Billing & Customer Service	4.24
Meter Losses	0.83
Meter Maintenance	0.40
Reduced Theft	3.50
Disconnection/Reconnection	2.80
Meter Lecture Verification	0.40
Total	12.17

VI. Demand Response Market Effects

A customers' electricity consumption pattern change, either through tariffs or other incentive mechanism, generates impacts on the operation of the system due to a change in price conditions faced by different actors [33]. A demand peak reduction means less dispatch of expensive generation capacity, such as those operating with diesel. Similarly, energy displacement from peak to valley will generate an increase in prices during these hours.

In order to study the effects of customers' pattern consumption changes, a thermal re-dispatch model was developed. The model takes as input the output data determined by OSE2000, a sophisticated multi-node multi-dam stochastic hydrothermal optimization model used by Chilean authorities to determine regulated tariffs. OSE2000 takes as input historical hydrologies since 1960, in terms of water inflows to each reservoir, series and run-of-river generation plants. Thus, resulting dispatch and marginal cost correspond to expected values of the stochastic optimization.

A. Data Used

The following data used was obtained from input/output data from OSE2000 model, which was used for preliminary node prices determination for October 2008:

- Hydroelectric generation for each hydrological sequence.
- Variable operation costs, failure rates, generation

expansion plan and maximum generation power.

- Energy demand projection and monthly demand blocks, i.e. height and duration of peak and valley blocks.

B. Developed Model

A thermal re-dispatch model was developed, which considers as initial condition the hydroelectric generation determined by the OSE2000 model. Model output permits the study of the impact on interest variables due to a modification of demand blocks structure. The mathematical formulation is:

$$Min \quad \sum_i \sum_j \sum_k \sum_g CV_g \cdot PGen_{i,j,k,g} \cdot HB_{j,k}$$

subject to

$$\sum_g PGen_{i,j,k,g} = \frac{ETerGen_{i,j,k}}{HB_{j,k}} + aux_{caso,k} \cdot DR_{i,k}$$

$$0 \le PGen_{i,j,k,g} \le PGenMax_g$$

where

$$DR_{i,k} = \begin{cases} MW_i & if\ k=2 \\ \dfrac{MW_i \cdot HB_{k+1}}{HB_k} & if\ k=1 \end{cases}$$

$$ETerGen_{i,j,k} = ETotGen_{i,j,k} - EHidGen_{i,j,k}$$

with

CV_g : *Generator g variable operation cost*

$PGen_{i,j,k,g}$: *Power generated by g in year i, month j, block k*

$PGenMax_g$: *Maximum power of g*

$HB_{j,k}$: *k block duration in month j*

$ETerGen_{i,j,k}$: *Energy generated by thermal plants in year i, month j, block k*

$ETotGen_{i,j,k}$: *Total energy generated in year i, month j, block k*

$EHidGen_{i,j,k}$: *Energy generated by hydro plants in year i, month j, block k*

$DR_{i,k}$: *Power reduced / increased in year i, block k*

MW_i : *Power reduction attributed to demand response*

$aux_{caso,k}$: *Auxiliar variable which allows to modelate different cases*

Basically, it consists of a thermal dispatch problem in strict merit order. The thermal demand is assumed to be the difference between system demand and hydroelectric generation determined by the OSE2000 model for each simulation, year, month and demand block. Departing from an optimal solution in terms of hydrothermal dispatch (long-term dam use), the interest is to determine which units are less dispatched on peak hours due to a peak shaving caused by customers' demand response. In a similar way, one needs to know which units will take an increase of valley demand due to a load displacing effect. Thus, changes of system marginal costs for small demand perturbations can be identified. The model determines $PGen_{i,j,k,g}$ for each analysis case studied and for every simulation. System marginal cost is determined as the variable cost of the last dispatched unit. Variable $aux_{caso,k}$ is defined to simulate different demand response cases further explained in E.

C. Model Validation

Fig. 8 shows quarterly marginal costs projected by OSE2000 model and by the model developed in this paper. It shows the existence of a clear correlation between the quarterly average marginal cost of the model developed and the one predicted by OSE2000. There are some differences though, because the model does not include restrictions on the transmission system and a weekly modeling of maintenance schedules.

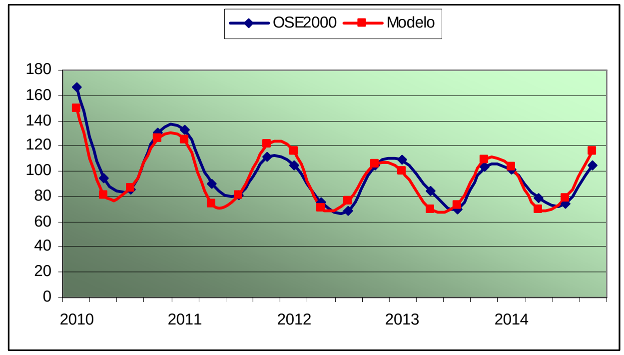

Fig. 8: Model validation; quarterly marginal costs.

D. Demand response modeling

Several researches estimate customers' price elasticity given different tariff schemes through a variety of methodologies [3, 8, 13, 19, 28]. However, such studies present results for certain particular realities, thus taking these values does not guarantee a realistic simulation of the customers' expected demand response for the case studied. In fact, ref. [1] models a fixed demand reduction to study the impact of demand elasticity in hydrothermal systems. Because of this, it is chosen to perform a sensitivity analysis considering different customers' response to various tariffs schemes. A 2.5, 5, 7.5 and 10% peak demand reduction on the installation zone was studied, assuming a 64% load factor for customers inside it. Four cases of possible demand response were studied:

Case 1 – Load displacing from peak to valley hours

A decrease of peak demand block height is considered for every month in the year over the entire study horizon. It is assumed that reduced energy consumption on peak is recovered in valley hours.

Case 2 – Peak shaving

Identical to Case 1, with the exception that energy not consumed on peak is not recovered in valley hours.

Case 3 – Load displacing from peak to valley hours during high power demand months

Peak demand block is shaved only on months where peak hours are modeled, namely: April, May, June, July, August and September. It is assumed that reduced energy consumption on peak is recovered in valley hours during those months.

Case 4 – Peak shaving during high power demand months

Same as previous case, but without considering energy recovery in valley hours.

E. Results

Results are presented for every case studied and for each demand response scenario. A 20 year time horizon was considered along with a 10 % discount rate.

Marginal Costs

Energy-weighted average system marginal costs were determined for a 5 year period, in order to identify demand response impacts on system costs. Fig. 9 show the results for peak and valley blocks for each case and demand response scenario studied. Note that both vertical axes are equally scaled, allowing to observe relative changes between peak and valley blocks. It is seen in all cases that, on average, peak blocks' marginal costs decrease more than the increase on valley blocks. In cases 2 and 4, valley block costs have no variation since in this cases energy is not recovered.

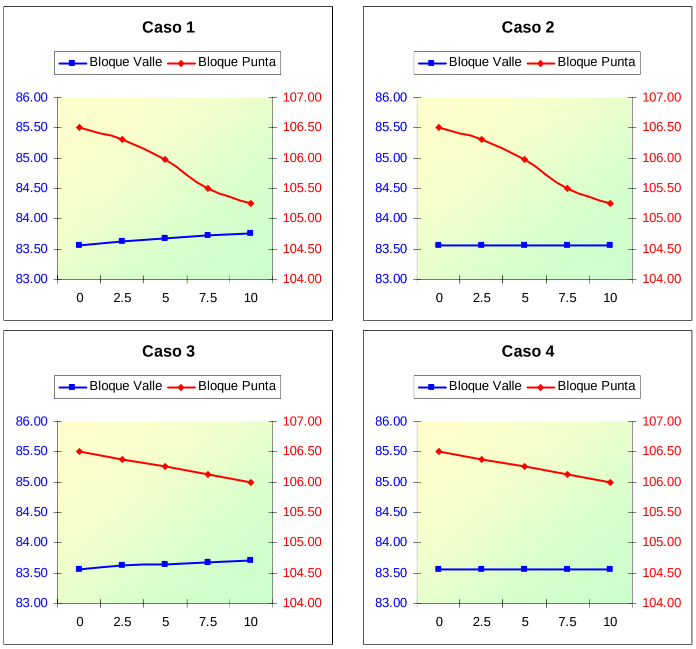

Fig. 9: System marginal cost impacts for each case and demand response scenario.

Generation Operation Costs

The present value of system generation costs was determined for each case and demand response scenario. Table 4 shows the results, considering a base case present cost of MMUS$ 9,357. All cases show a decrease in the total costs of generation along the horizon of study, which is logical due to the reduced use of peaking power plants. It is also clear that the strategies that lead to energy displacement from peak to valley (Cases 1 and 3) do not have an impact as significant as the strategies that lead to energy conservation (Cases 2 and 4).

TABLE 4
OPERATION COSTS SAVINGS [MMUS$]

	Demand Response			
Case	2.5%	5.0%	7.5%	10.0%
1	1.58	3.13	4.64	6.12
2	8.04	16.06	24.04	31.99
3	1.13	2.25	3.35	4.43
4	6.19	12.37	18.54	24.70

Generation Profit on Marginal Cost Market

Revenues collected at marginal costs represent those which the generation sector would receive if all energy would be sold on a monthly spot market. Considering the evolution of costs and revenue in the generation park, it is possible to determine the extent to which operating margins in that segment are affected. Table 5 shows how generation profit changes. It can be seen that generation profits decrease in every case, which lead one to conclude that revenues decrease more than costs do.

TABLE 5
GENERATION PROFIT CHANGE [MMUS$]

	Demand Response			
Case	2.5%	5.0%	7.5%	10.0%
1	- 6.36	- 35.12	- 78.53	- 98.48
2	- 26.22	- 66.86	- 125.98	- 157.99
3	- 0.60	- 9.39	- 16.77	- 25.87
4	- 18.80	- 34.21	- 52.72	- 69.21

Generation Profit on Contract Based Market

A contract based market corresponds to one in which distributor utilities sign long term energy supply contracts with generation companies, typically indexed to fuel costs. The revenues of the generation sector remains constant for Cases 1 and 3, since the same amount of energy is sold at auction determined price. Obviously, for other cases they decrease due to diminished energy consumption. Table 6 shows how generation profit changes on contract based markets. It is noted that in this case, costs decrease at a higher rate than revenues, thus yielding a profit increase for the generation park.

TABLE 6
GENERATION PROFIT CHANGE

	Demand Response			
Case	2.5%	5.0%	7.5%	10.0%
1	1.58	3.13	4.64	6.12
2	1.98	3.94	5.86	7.76
3	1.13	2.25	3.35	4.43
4	1.46	2.91	4.35	5.77

Energy saving incentives

Chilean regulation allows generator companies to negotiate temporary reductions/increases of energy consumption with groups of customers subject to price regulation. A generator company publishes an offer in which it stipulates the incentive value in $ per kWh, the offer's duration, and the maximum energy consumption reduction subject to payment for each customer in terms of its determined reference consumption.

In theory, under perfect competition in energy savings offerings, the optimal equilibrium incentive price is the difference between expected marginal cost in the period and the value paid by customers, determined by auctioned long term supply contracts. Under these conditions, social welfare is maximized passing all benefits to final users.

It is assumed that generators offer this optimal price incentive to customers during the months of March, April, May and June. Considering offers carried out during 2008, generators aim to reduce a 4, 3, 2 and 1% of regulated customers' monthly energy consumption during previously cited months, respectively. This is because hydrological uncertainty is present during these months, thus rising marginal costs due to strategic water conservation. It is supposed that the offering intention is to reduce peak power supply, thus energy to power translation is done by using regulated customers load factor, assumed to be 64%. For sake of simplicity, a 100% load factor is assumed during peak hours. Results are shown in Table 7.

TABLE 7
PV OF INCENTIVES COST [MMUS$]

Case	Demand Response				
	0%	2.50%	5%	7.5%	10.0%
Without Smart Meter	44.35	41.26	38.16	35.07	32.04
With Smart Meters	32.66	31.01	29.38	27.75	26.20
Smart Customers	11.75	10.12	8.51	6.90	5.36
Dumb Customers	20.91	20.89	20.87	20.85	20.84
Benefit	11.69	10.25	8.78	7.32	5.83

Aiming at the same target, benefits in terms of incentive payment savings is evident. This is because smart metering allows paying for reductions in consumption at times when it is really necessary. Actual metering makes it necessary to pay for reductions regardless of the time it happened i.e. valley hours, which is indeed a waste of resources. Benefits identified in Table 7 clearly belong to the generation park, nevertheless they will not be considered since the inefficiency of the mechanism is not sustainable in the long run.

VII. Project Valuation

This section consolidates the results of previous ones, in order to identify the convenience of the installation of new metering technologies.

A. Customer Costs and Benefits at Distribution Level

Under perfect regulation of the distribution sector, full costs and benefits are transferred to customers. Under this scenario, considering all costs and benefits identified in previous sections, evaluation would look as indicated in Fig. 10. Costs hugely outweigh benefits, mainly due to high capital costs.

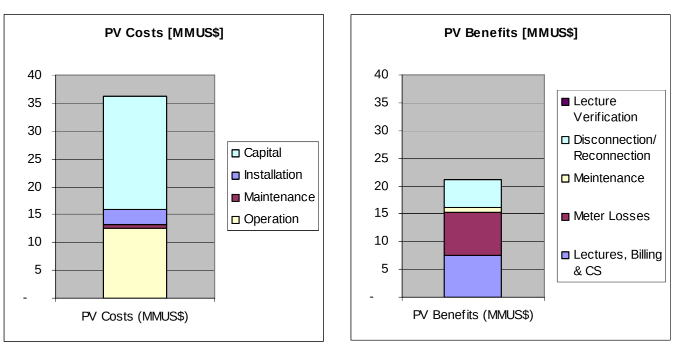

Fig. 10: Present values of costs and benefits.

B. Marginal Cost Market

Project's Net Present Value (NPV) is analyzed for all system users and for customers subject to installation in a marginal cost based market. Present values of costs and benefits identified in A. are taken into account, to which demand response benefits are summed for different cases and scenarios.

Customer NPV with DR

Fig. 11 shows project's NPV for all system customers. Under most scenarios, the project is profitable for all system customers.

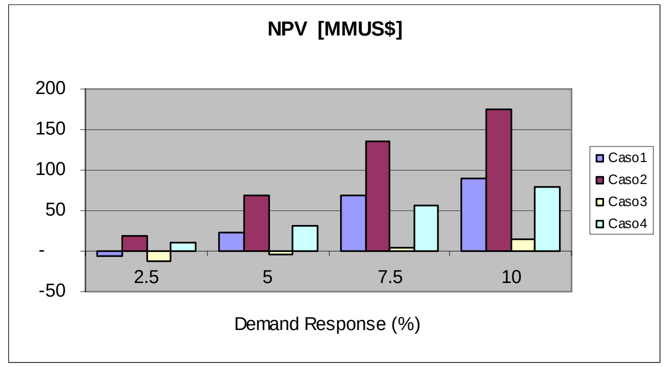

Fig. 11: Customers' NPV in marginal cost based market.

Zone Customer NPV with DR

Fig. 12 shows project's NPV for installation zone customers. Benefits are exceeded by costs. One can conclude that in a marginal cost based market, the project is profitable, but not for users originating the benefits which, by the way, are funding the project.

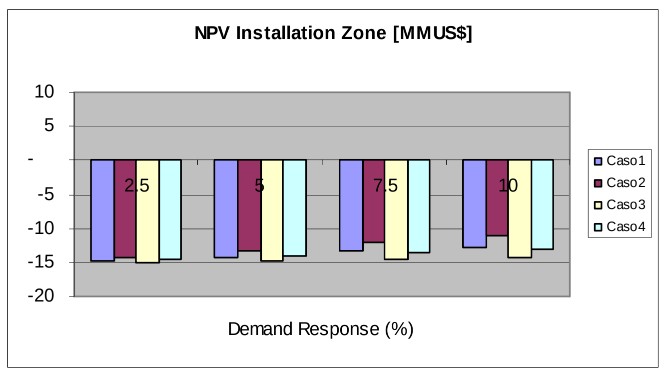

Fig. 12: Installation zone customers' NPV in marginal cost based market.

C. Contract Based Market

Project's Net Present Value (NPV) is analyzed for all system users and for customers subject to installation in a long term contract based market. Present values of costs and benefits are considered, to which incentive payment present value is summed.

Customer NPV with incentive payments

This case examines the project's NPV to all users, which considers energy saving incentive payment to users with smart meters. However, because it is impossible to achieve reduction target only by them, traditional inefficient payment to "dumb" users is considered. Fig. 13 shows the project is profitable for all cases. Note that the greater the demand response, the smaller the benefit to users because there are fewer payments from generator companies. Remember that in a market at a fixed price, the users demand response constitutes free savings the generator park.

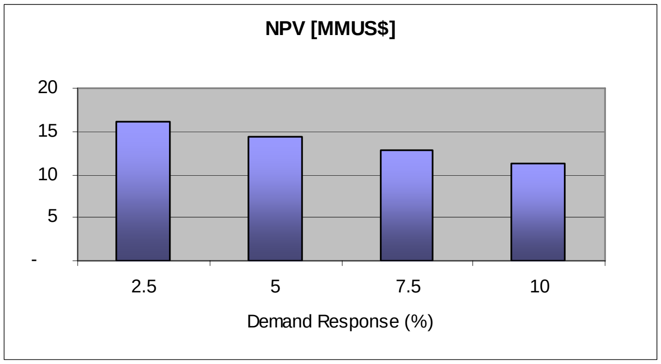

Fig. 13: Customers' NPV in contract based market.

Zone Customer NPV with incentive payments

Analysis is now focused on the installation zone customers. Cost and benefits from A are considered to which present value of efficient incentive payments is summed. Fig. 14 shows project's NPV for this scenario. The project is unattractive from the perspective of users within the installation zone. Again, it is noted that energy saving incentive payments are greater whereas tariff demand response is low and vice versa.

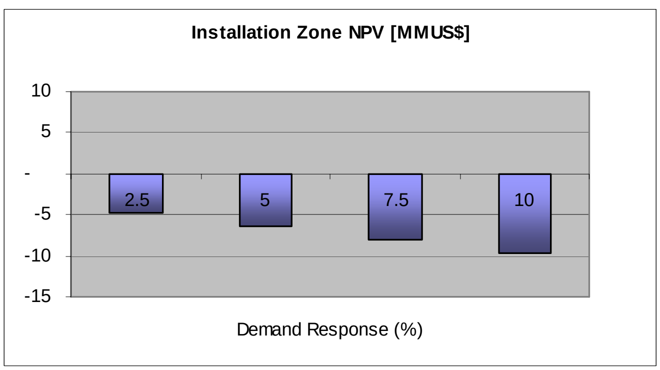

Fig. 14: Installation zone customers' NPV in contract based market.

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The analysis of contract based market allows one to conclude that inefficient incentive payments, like the one implemented in Chile, may finance an expensive project like smart metering implementation in the area studied.

VIII. Conclusion

A methodology of technical-economical evaluation of the introduction of smart meters in a developing country is proposed, and evaluated for Chile.

In particular, an area selection methodology was developed aimed at finding a delimited geographical zone within a city, in which customers' demand response could be maximized due to an introduction of smart metering technologies.

Smart metering implementation costs were estimated, considering installation, capital, and operation and maintenance costs. Distribution level benefits were identified and assessed along with operational impacts on power generation sector due to demand response effects. Also, efficient energy savings incentive payments from generators were determined and compared to a non efficient scenario in which payments are realized independent of when consumption is reduced.

It is found that the installation of smart meters in the determined zone generates benefits to society as a whole, but not to customers within the area of installation, who originates the benefits and pays for the meters. Under these results, it is highly unlikely that customers would be willing to finance this project, but due to societal benefits, regulators should study alternative centralized financial solutions.

The analysis could be pursued further if customers' demand response modeling was available, considering empirical evidence on their consumption behavior when facing time varying price signals. To assess system reliability benefits, it would be of interest to study the impacts on loss of load probability when flexible, price sensitive demand is modeled.

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