

## SMART METERING IN GAS – REVENUE POTENTIAL OR WASTE OF MONEY?

### Itron is bringing clarity to your investment decisions

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#### SUMMARY

*In this paper Itron introduces a consulting methodology that goes beyond the traditional feature to benefit approach, and concentrates instead on a problem-focused risk management approach. Following five easy steps, risks are identified, prioritized, their impact assessed and risk mitigation options selected that build the fundament for a risk management strategy.*

*Working with customers in Turkey, risks on regulatory compliance / rate making, supplier dependency, exchange rate exposure, timeliness of readings, outstanding receivables, meter rightsizing and tamper detection as well as their potential impact have been identified, going far beyond the usual evaluations of efficiency improvements.*

*Using Itron's new consulting service, utilities in Turkey and around the world are assessing whether changing the metering infrastructure to smart technologies is adding value or not. As proven in Turkey addressing one or two issues might be sufficient to pay for a complete roll-out.*

#### ABSTRACT

*So you are thinking about implementing a smart grid infrastructure. You have read all the relevant documentation and standards and looked at the newest and most innovative technologies. You have even talked to existing smart grid users about their experience. But with all of that information there is still this lingering question – is smart grid the right path for my utility?*

*The traditional model to support your decision process is a cost-benefit analysis. More often than not, these analyses follow a feature oriented approach. Starting from technology, the customer implementation environment is evaluated and a path is suggested to realize certain benefits offered by a specific feature.*

*Furthermore smart metering is frequently focused on efficiency improvements to the key utility operational processes. This is even truer for the gas industry: some of the major smart metering drivers for the electricity utilities such as peak load reduction or load control do not apply to gas.*

*Especially in the quickly developing countries, operational efficiency is not a key factor either – low labor costs often*

*outbalance the substantial cost of a smart meter implementation.*

*In this paper Itron introduces its consultancy service for gas utilities that follows a much broader, problem focused approach. Instead of starting from features and afterwards finding problems that can be solved with this technology, Itron's consulting services take a technological neutral standpoint and focus on the core building blocks that make up a gas utilities' business model to identify relevant external and internal risks.*

*In his article, André Wankelmuth, director of strategic market development at Itron, provides insight into Itron's methodology and puts a special focus on key findings as they relate to the Turkish market.*

#### ÖZETÇE

*Demek ki akıllı şebeke altyapısı uygulamayı düşünmektesiniz. Konu ile ilişkili tüm dokümantasyon ve standartları okuyup, en yeni ve en yenilikçi teknolojileri incelediniz. Hatta mevcut akıllı şebeke kullanıcıları ile deneyimleri hakkında görüştünüz. Edinilen tüm bilgilerle bile şu daimi soru hala mevcuttur – akıllı şebeke idarem için doğru bir yol mudur?*

*Karar sürecinizi desteklemek için geleneksel model maliyet-fayda analizidir. Çoğunlukla, bu analizler özellik odaklı bir yaklaşım takip eder. Teknolojiden yola çıkarak, müşteri uygulama ortamı değerlendirilir ve spesifik bir özellik tarafından sunulan kesin faydaları gerçekleştirmek için bir metot tavsiye edilir.*

*Ayrıyeten akıllı ölçüm, çoğunlukla idarenin ana işlevsel süreçlerinin verimlilik gelişimine odaklanır. Bu durum gaz sektöründe daha da doğrudur: azami yük azaltılması veya yük kontrolü gibi elektrik idarelerinin başlıca akıllı ölçüm faktörlerinin bazıları gazı uygun düşmez.*

*Özellikle hızlı gelişen ülkelerde operasyonel verimlilik temel etken değildir – düşük işçilik maliyetleri genellikle akıllı sayaç uygulamasının büyük maliyetinden daha ağır basar.*

*Bu bildiriye Itron; gaz idareleri için daha kapsamlı, problem odaklı danışmanlık hizmetini tanıtmaktadır. Özelliklerden*

*başlayıp devamında da bu teknoloji ile çözülecek sorunları bulmaktansa; Iron'un danışmanlık hizmetleri tarafsız teknolojik bakış açısı ile yaklaşır ve gaz idarelerinin ilgili dış ve iç risklerini tanımlamak için iş modellerini düzenleyen temel yapı taşlarına odaklanır.*

*Iron'un stratejik pazar geliştirme direktörü André Wankelmuth bu makalesinde Iron'un metodolojisine ışık tutmaktadır ve Türk Pazarı ile ilgili temel bulgulara özel olarak odaklanmıştır.*

## 1. LOOKING BACK

Smart metering and smart grid have become the most important topics of conversation in the energy industry. Smart Grid is supposed to solve the challenge of the ever growing energy demand on the one end and increasing scarcity of energy resources on the other.

When a utility wants to evaluate if the implementation of a smart grid is the right path to pursue, the question comes down to the payback of that major investment: the return on invest (ROI). The traditional model to support that decision process is a cost-benefit analysis (CBA) factoring in tangible and intangible assets like increased brand value, innovation, environmental aspects.

These analyses usually follow a feature-oriented approach. Starting from a technology choice, the customer's implementation environment is evaluated and a path is suggested to realize certain benefits offered by each feature. In JRC's Reference Report on Guidelines for conducting a cost-benefit analysis for Smart Grid projects (Giordano, et al., 2012), the following 4 steps have been determined:

- "identify each technology and program that fits within the scope of smart grids;
- identify benefits of each technology / program [...];
- identify technology, installation program and management costs based on utility and customer characteristics;
- compare costs and benefits to determine investment returns [...]"

Giordano et al. expand the scope in their proposed guidelines to include societal benefits and consumer benefits, as well as qualitative impact analysis and sensitivity analysis on the quantified benefits. But at its core the proposed procedure still starts with technology and then derives benefits from the provided functionality (refer to Figure 1).

Iron has observed that many international markets have focused on a technology driven discussion that resulted in quiet detailed technical specifications, with no clear answer to the

question: "What problem do we want to solve with this technology?"

The second breakdown is manifested by the fact that especially for gas-only utilities, the business case is becoming very hard to justify. Big business case drivers for electricity utilities such as Peak Load Reduction or Demand Side Management do not apply to gas utilities, often leaving only a very narrow approach focusing on generating benefits from operational efficiency improvements. Benefits like automation of meter reading, back office savings, synergies / better management of field work orders or billing automation, etc.

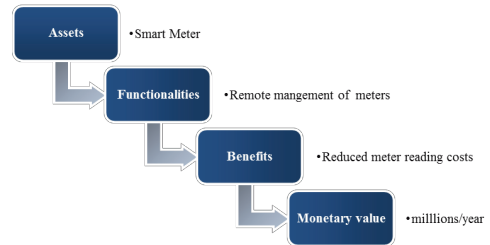


Figure 1: Methodology for performing a CBA (own representation acc. Giordano, et al., 2012)

These benefits are often not sufficient to provide a positive cost-benefit result. This is even truer for countries with low labor costs such as Turkey. Using the example of reading automation, with a price of about €0,50 per successful read and the requirement of bi-monthly reads the total cost per year add up to €3. Introducing a GPRS based smart meter to automate the process would add up to €4-6 per year on communication cost alone - even a well-negotiated telecommunication contract will be in the range of €0,30 to €0,50 per month. Asset costs and installation and maintenance costs are not even considered in this example.

Are we at a dead end for gas utilities who want to go smart? Not at all! We just need to take a different approach that is not driven by technology and take a wider angle instead of looking at operational efficiency only.

## 2. CHANGING THE APPROACH

Technology is helping to solve problems; if it does not help, there is no reason to implement it. Therefore the starting point has to be identifying the problem first and then deciding on the technology that solves that problem.

Iron takes a risk management approach to this challenge looking at the end-to-end utility's business model (adapted from Kunreuther (2014)) as shown in Figure 2.



Figure 2: Risk management approach – own representation adapted from Kunreuther (2014)

Starting from a completely neutral technology standpoint, Itron looks at each building block of the business model from customer segments, revenue streams and key activities to key partners and cost structure. Furthermore Itron tries to identify all potential internal and external risks that might impact the business model (refer to Figure 3 for the main challenge areas for gas utilities).

Having identified the key risks Itron prioritizes according to potential impact and likelihood of occurrence. For the top risks, an assessment of the minimum and maximum financial impact is performed based on Itron's more than 100 years of industry expertise and experience from smart metering roll-outs all over the world.

Only in step four after identifying and qualifying the risk will Itron be looking at the technology components and at their ability to address, solve or at least minimize the dedicated risks. After selecting the right technology components, a potential end-to-end solution is designed that establishes the core for successful mitigating the risk using smart metering technologies. Each strategic option is then commercially assessed via a comprehensive net present value (NPV) analysis (financial model using the time value of money to appraise long-term projects).

This process clearly outlines whether there is a pay back and whether it makes sense to invest in smart technologies or not. The net present value and the calculated internal rate of return (profitability of the investment) are fundamental in supporting the selection process for the right option.

Step six and seven are mainly driven from the side of the utility, with Itron taking a more supporting and consulting role.

The gas utilities industry is changing dramatically highlighting the importance of managing risks: "[...] The utility sector used to be considered a crisis-proof industry. This no longer applies. Economic and political framework conditions have become less predictable. To us, systematically recording, assessing and controlling risks is more important than ever before [...]" (RWE Aktiengesellschaft, 2012, p. 88). This increased risk

scenario is not limited to European markets either. Itron's customer Brazilian gas utility for example is not only looking at managing market risks, operational risks and financial risks, but also supply risks, environmental and regulatory risks: "[...] This Brazilian gas utility has a standing committee that monitors, discusses, and adopts measures to minimize exposure to risk affecting operations and / or performance. [...] As a support tool, it structured the online risk management system that it has been using for five years." (Brazilian gas utility, 2012, p. 40).



Figure 3: Gas Utility Challenges and Risks

Global support for like the statements above encourage Itron to continue working and enhancing this approach to create extended value for our customers. Whereas some challenges generally apply for gas utilities around the world, the specifics are dependent on each customer's situation and need to be looked at individually.

What is becoming very quickly apparent is the fact that utility challenges are much broader than looking at operational efficiency only. Itron has identified a comprehensive set of key gas utility challenges at stake (refer to Figure 3).

Safety and security is a major topic for two reasons: 1) The main value proposition to consumers is the secure and safe supply of energy. Nobody wants to cook and heat with gas if there is a safety hazard. 2) The gas infrastructure (pipes and meters) is the central, most costly and valuable asset in a distribution service operator's business. Because of these reasons, leak detection, ensuring system integrity and anticipation of ageing patterns for piping and metering assets are some of the main challenges in these categories keeping utilities' managers awake at night.

Network delivery performance challenges include the provision of adequate capacity for peak demands (e.g. during a cold winter day), but at the same time the challenge to not oversize the infrastructure and guarantee a high asset utilization. Furthermore, constant monitoring of pressure stability and gas quality is required for proper network delivery performance.

Especially in developing nations (not only there, but in developed countries as well) and due to rising energy prices

across the globe, revenue protection is a major challenge. How can utilities ensure that the revenues for the services provided can be recognized in order to get a return on the huge investments made for the smart grid infrastructure? Questions along the lines of assuring cash flows, the reduction of outstanding receivables and the reduction of internal and external apparent losses need to be addressed.

Very well known of course is also the discussion about how to engage and satisfy the end consumer. What new services can be offered? Improvement of supply and payment convenience, reduction of customer complaints, budget control support and delivering meaningful information to consumers are major topics to be taken into account.

Profitable operation and management of a regulated business with changing framework conditions is undoubtedly a very important aspect as well. Thus regulatory compliance in respect to rate making, fair and accurate billing and reduction of the company's CO2 footprint are major themes to be assessed.

Managing scarce energy resources is the major challenge of our century. In the risk category 'resource management', Itron looks at the energy resource gas itself, but also at the utilities' resources in a broader sense. Themes of interest are the reduction of gas losses, security of supply (ensure availability and new customer connection), customer and employee retention, unbalanced trade conditions or price volatility impact.

Looking at all themes above, it is fair to summarize that there are many more challenges than just operational efficiency improvements that have to be considered when evaluating the benefits of smart technologies. With its proven evaluation technique and methodology, Itron has gained insight into these themes and has built a point of view on how smart technologies can help to manage these risks.

### 3. APPLYING THE METHODOLOGY - HOW DOES IT LOOK IN PRACTICE?

Let us take an example to illustrate how the methodology works.

#### Step 1: Identify risks

Reading the annual report of Brazilian gas utility, a gas utility in Brazil, on average 1.4 months of outstanding receivables can be identified. In Turkey outstanding receivables of up to 2.8 months have been observed. It is obvious there is a problem of bill to cash that has to be addressed.

Efficiency improvements in data collection using smart meters will reduce the time between metering and bill issuance, but not

the time from sending the bill until the revenue is recognized. The risk has to be addressed differently.

#### Step 2: Prioritize risks

As only a single risk is used in this example, prioritization is irrelevant. Nevertheless outstanding receivables have a direct cash impact and with an average of 2.8 months outstanding, the likelihood of this risk manifesting is very high.

#### Step 3: Risk assessment

For the sake of illustration let us take two months (60 days) of outstanding receivables as a baseline. In an utility with 1,000,000 end customers and \$700 M yearly revenue, 60 days outstanding receivables amount to about \$115 M ( $\$700 \text{ M} / 365 * 60$ ) or \$115 per customer. Using a technology that limits the outstanding receivables to 5 days, a one-time benefit of about \$105 M could be realized. This alone could already pay for the investment needed to change the meter base to smart meters.

#### Step 4: Risk management options

One specific technology (among many) addressing the identified challenge is "Pay-As-You-Go". The payment period (e.g. 1 month) is programmed in the smart meter. At the end of the payment period, the meter gives a warning and the consumer has a five day grace period to pay the total volume of gas that was consumed. If the consumer doesn't pay the total outstanding volume on the meter, the valve of the meter will close until the total outstanding volume is paid (refer to Figure 4 bottom picture). The outstanding receivables are reduced to 5 days.

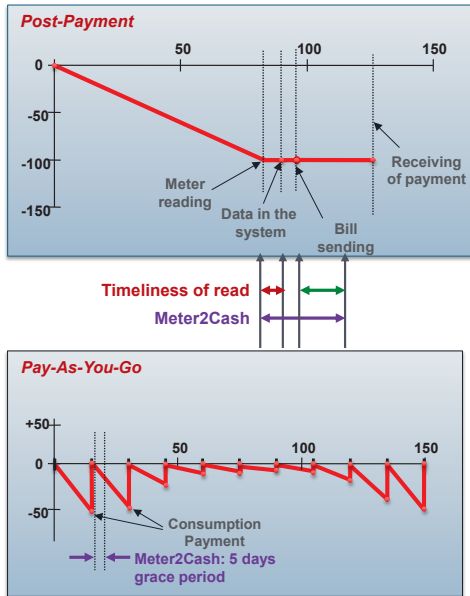


Figure 4: Meter2Cash cycle conventional post payment and PayGo (Pay-As-You-Go)

Whether it makes sense to include the “Pay-As-You-Go” technology in a final end-to-end solution depends on the complete problem landscape that needs to be assessed.

4. FINDINGS FOR TURKEY

Geographically Turkey enjoys a very favorable position being located between Europe, Middle East and Asia with gas pipelines from main energy producers such as Russia, Azerbaijan and Iraq traversing the country.

With a strong growth in GDP in the past years (4.5% between 2002 and 2009) and the actual growth in 2013 still reaching 2.1%, Turkey shows that it can withstand adverse global economic environments.

Due to its strong economic growth, Turkey’s energy demand is increasing quickly. Natural gas plays a dominant role (17% CAGR since 1988) in industrial use, electricity generation and residential use for cooking, heating and hot water. This trend is expected to continue in the future. Interest rates at a historical low rate of 4.5% and forecasts extend this rate even more.

With the Natural Gas Market Law 4646 issued in 2001, Turkey’s Energy Market Regulatory Authority (EMRA) started the liberalization of the Turkish energy market. Intended to

foster the uptake of natural gas, infrastructure distribution and supply activities have been privatized. This allows for increased market competition, followed by a diversification in offerings, a reduced monopolistic dependency and improvement in end customer service, quality and pricing.

Rate making / regulatory compliance risk

In the privatization process the Turkish regulator EMRA assigns licenses to distribute gas in a certain area based on a tendering process with the successful bidder obtaining a guarantee for a fixed distribution margin for a period of eight years. After the initial eight year period, the tariff is calculated based upon the investments made by the distribution service company with both capital and operational expenditures being considered in the calculation (refer to Figure 6).

Regulators aim to limit the profit of distribution service operators as they operate in a local monopoly but at the same time regulators want to ensure a fair return on the investment done by the operator. The revenue calculation in Turkey as defined by EMRA follows a regulatory asset base (RAB) approach with a revenue income cap (Perrin & Chosson, 2013, p. 7). Other European countries like France or the Netherlands follow incentive-based approaches or a mixture of both like e.g. in Greece, Italy or Spain.

In principle RAB schemes calculated the so called “revenue requirement” (capped revenue) based on the non-depreciated assets the company acquired multiplied by the allowed rate of return. The annual depreciation, operating expenses and taxes are then added to the sum (refer to Figure 5).

$$R = B \times r + d + E + T$$

- R Revenue requirement
- B rate base, capital or assets the utility dedicates for service provision
- r allowed rate of return
- d annual depreciation expense
- E operating Expenses
- T all taxes not counted as Opex and not charged to customers

Figure 5: Rate calculation principle for regulatory asset base approaches with revenue cap

In principle the same approach is used by the regulator EMRA in Turkey: The asset base (ODVT and SHDVT) is multiplied by the rate of return (RMGO) and amortization (I) and operating expenses (IG and DG) are added to the equation (refer to Figure 6)

$$GG_t = (ODVT_t + SHDVT_t) * RMGO + I_t + (IG_t - DG_t) + ISG_t$$

GG Annual revenue requirement  
 ODVT Adjusted asset base  
 SHDVT Non-network adjusted asset base  
 RMGO real rate of return

$I_t$  Amortization for investments in the tariff year  
 $IG_t$  Adjusted operating expense  
 $DG_t$  Side revenue  
 $ISG_t$  Adjusted working capital

Figure 6: EMRA rate calculation

When looking at the formula in Figure 6, it seems that it is irrelevant to work on efficiency improvements as operating expenses (OPEX) are recognized in the tariff as well. Itron found out in a specific case analyzed that the allowed annual revenue calculated was very similar for a scenario with more capital expenditure (CAPEX) heavy smart meters going in hand with optimized OPEX as for a less CAPEX intense scenario with more manual OPEX heavy processes. But the impact on the bottom line net income (= Allowed revenue – costs of goods sold – sales, marketing and general expenses) was extensive: depending on the scenario, the net income was double to triple as high for the case with higher automation compared to the lower automation case.

One surprise finding in the analyzed case was that the initial agreement (refer to explanation about privatization process above) was very favorable and that the revenue cap would be reduced by about 50% after the initial period although heavy CAPEX was factored into the period before the official rate was applied. This finding enables the customer to anticipate and prepare for the time ahead requiring the implementation of focused cost avoidance measures.

**Supplier dependency, exchange rate exposure**

EMRA’s target is to increase the amount of gas imported by privately owned companies to more than 20% and foster competition. This shall be achieved by demanding distribution service companies to obtain less than 50% of their gas from a single source. In practice Botas is still the main source of gas in Turkey as changes are only slowly starting to materialize.

Long term gas supply contracts that are often still linked to oil indices are in their nature take or pay contracts. This bears two risks: First, gas market prices have been significantly lower than oil prices (€10-12 per MWh (RWE Aktiengesellschaft, 2012, p. 39)) which constitutes a risk of about USD 288 M for a distribution volume of 2 Bn m<sup>3</sup> (€11 / 100 m<sup>3</sup> x 1.31 x 2 Bn m<sup>3</sup>) for long term contracts linked to the price of oil versus gas market prices. Secondly, consumption below 80% of the contracted volume has to be paid regardless if the volumes have been delivered or not. From experience with cases in Latin America where supplier dependency was even lower, Itron could demonstrate that this is a risk of about 3% of the costs of goods sold. So for a utility distributing 2 Bn m<sup>3</sup> per year the risk amounts to about USD 26 M.

A better forecasting accuracy supports a stronger negotiation position on supply contracts, especially when market pricing is not linked to the oil index. The basis for proper forecasting is provided by a granular view of what amount of gas is consumed and what amount of gas was injected into the grid. This balancing of input and output is only possible having clear cut-off dates for which consistent sets of data are available across the whole meter park.

**Timeliness of readings, outstanding receivables**

Why is it difficult to have clear cut-off dates with consistent data? The reason lies within the manual reading process. The essential drawback of manual reads is that no data logging takes place in between each manual read. Thus no consistent set of data across the whole meter park at a defined cut-off date can be achieved. Refer to the left side of Figure 7. As only punctual data is available from the first and second reads and readings for different customers do not take place at the same time, consumption data from last read to cut-off date (green line) has to be estimated.



Figure 7: Timeliness of readings and clean cut-off date using walk-by smart technology

Besides a potential benefit of reducing labor costs via automation, smart technologies send granular data like last 30 daily index values or more are stored in a smart meter's or module's memory, making a clean cut-off possible. Figure 7 on the right side shows an example using a walk-by system. Readings are still taken at defined punctual dates, but in taking the read more granular (e.g. daily) data is collected from the smart meter. Latest at the date marked with "2" in the diagram, a clean cut-off is possible for the date marked "1".

In some instances the bills can be even printed on site, thus achieving a consistent cut-off date is not relevant from a billing point of view. From both a profit and loss point of view and an accurate forecasting point of view, a detection of losses (technical or apparent) through a clean cut-off is essential.

In cases where bill printing is not possible on site (either due to a technological or regulatory point of view), the timeliness of readings become important again, as it reduces read to cash cycle time (refer to Figure 8 time between meter read and bill generation). The timeliness of reading defined as the time it takes from taking the meter read until the data is in the system can be almost instant, for example if the handheld is equipped with a GPRS modem sending data to the head-end over the air. The time frame between "1" and "2" (refer to Figure 7) becomes zero if e.g. smart meters with fixed network architectures are used, that send in daily data.

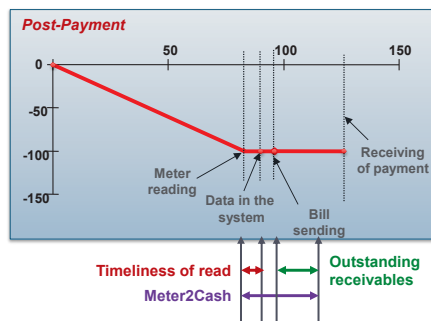


Figure 8: Meter-to-Cash Cycle: Importance of timeliness of readings and outstanding receivables

Another important aspect to influence the meter-to-cash cycle is the time between sending the bill and the moment the money is received in the bank account – the time of receivables outstanding. For customers that are not on direct debit accounts, this time can be up to 60 days or more and a certain percentage cannot be recovered at all, and are required to be written off as impairment of receivables. For a utility each day of receivables outstanding represents 0.247% of revenue (yearly revenue / 365 days). If the time between meters being read and having the data in the system for bill generation is two days and the average is 45 days of receivables outstanding, the outstanding receivables add up to 12.88% of revenue.

Minimizing these outstanding receivables often generates a one-time cash effect high enough to fund a smart roll-out project without considering other benefits.

### Meter rightsizing

Service points differ in consumption depending on the use of gas for cooking-only (low) cooking and hot water (mid) or cooking, hot water and heating (high). Apart from the core usage type, consumption will also differ based on customer segment residential, light commercial, or industrial.

The size of the meter measuring unit needs to be aligned with the main operating range to provide accurate data. Caliber mismatches can cause undercounting for low and high flow rates. Smaller engines age quicker when frequently operated at max flow. Bigger engines are less accurate at low flows and have a higher starting flow.

Looking only at monthly reads (refer to Figure 7) only an assessment of the average consumption is possible. With more granular data, peak usages on specific days of the week or specific times of use can be identified. This enables utilities to have a much more accurate assessment of caliber matching.

Assuming 3 to 5% of an installed base of around 1 M meters (equals 30k to 50k meters) are not properly matched to the application (e.g. small engine meter running almost all the time at Qmax) and assuming a 5-10% undercounting compared to the right-sized meter on a yearly distributed gas volume of 2 Bn m<sup>3</sup>, the impact can be calculated at around \$167 k per year to \$555 k. As the meter charge for bigger calibers is higher, an additional 0.32-0.54% revenue \$3.2 M to \$5.4 M can be generated.

### Tamper detection

Pipes and metering assets are key to a utility business model. The pipes are needed to transport and distribute the gas and the metering assets make sure that the main revenue and margin source (m<sup>3</sup> supplied) get accurately measured. If this baseline is not ensured, all planned investments to improve profitability will fail.

Due to an increase in energy prices and “so called” fuel poverty in many countries, tampering of gas meters in order to get free gas is on the rise. Tamper methods observed by Itron in the field range from metrological seal forging, meter reversal and removal, register clamping and drum blocking with hot wires to more sophisticated methods of magnetic or electromagnetic interference tampering or interval tampering by disconnecting the meter from the grid for a certain period of time.

Preventing tampering through meter design is to a certain degree possible e.g. by using non-magnetic materials or back-run protection in the measuring unit. When prevention is not possible or sufficient, advanced detection mechanisms help to identify gas theft attempts. Smart meters provide the added possibility of taking preventive or corrective action. Detection is possible in a direct manner via advanced sealing mechanisms, alarms provided by smart meters or indirect via data mining on the data collected.

Using smart technologies, the meter can be read remotely without entering the house, rendering an up-front information unnecessary. Due to data logging smart metering solutions can record interval tampering on meter level and a more advanced analysis can be performed on the system level including the evaluation of tamper sensor information, thereby allowing easy detection of even sophisticated tampering behavior.

The losses due to tampering events observed by Itron vary between 4% of unaccounted for gas in developed nations and 7% in developing nations. The impact for a utility assuming conservative 3-5% apparent losses on a yearly residential distribution volume of 1 Bn m<sup>3</sup> is a margin effect in the range of \$1.7 M to \$2.8 M.

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